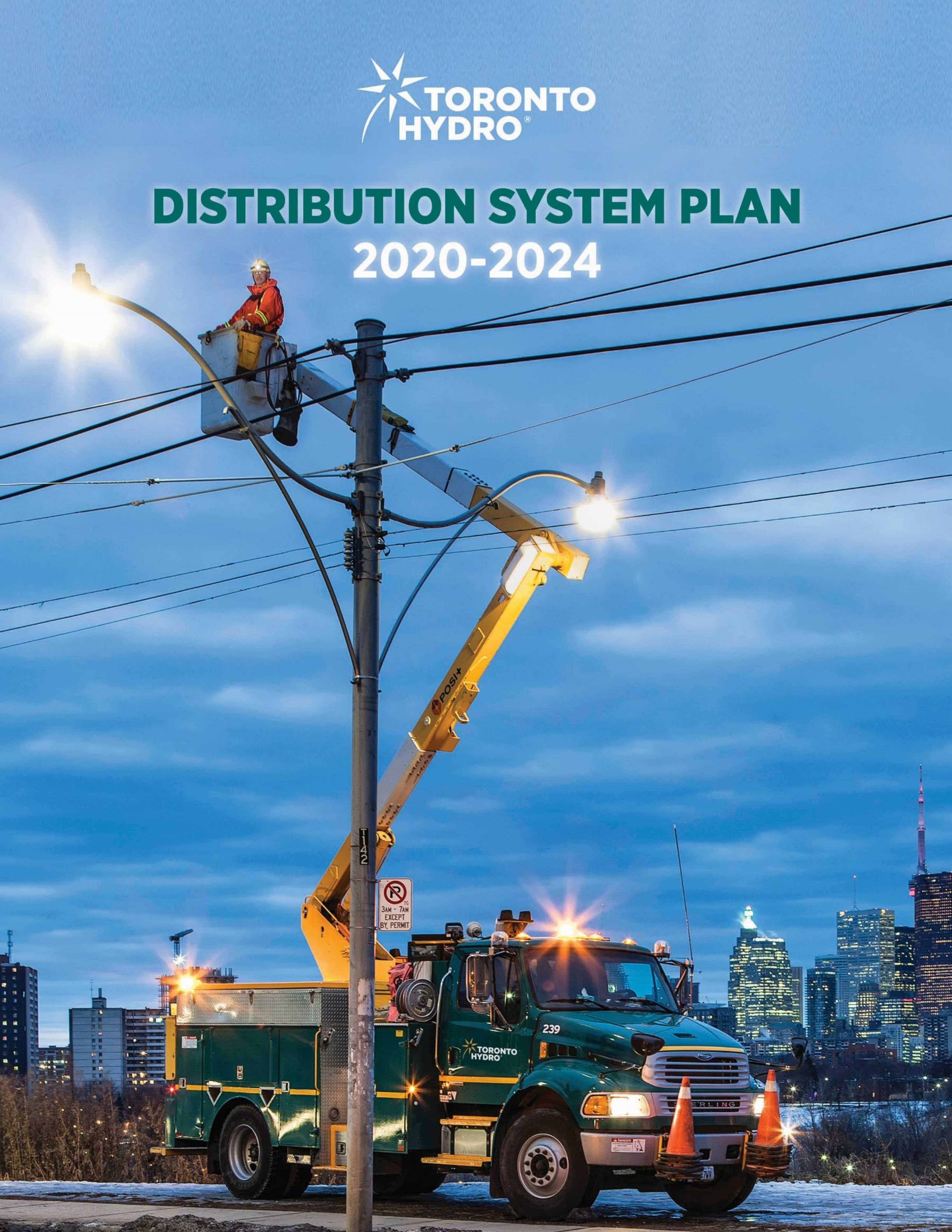
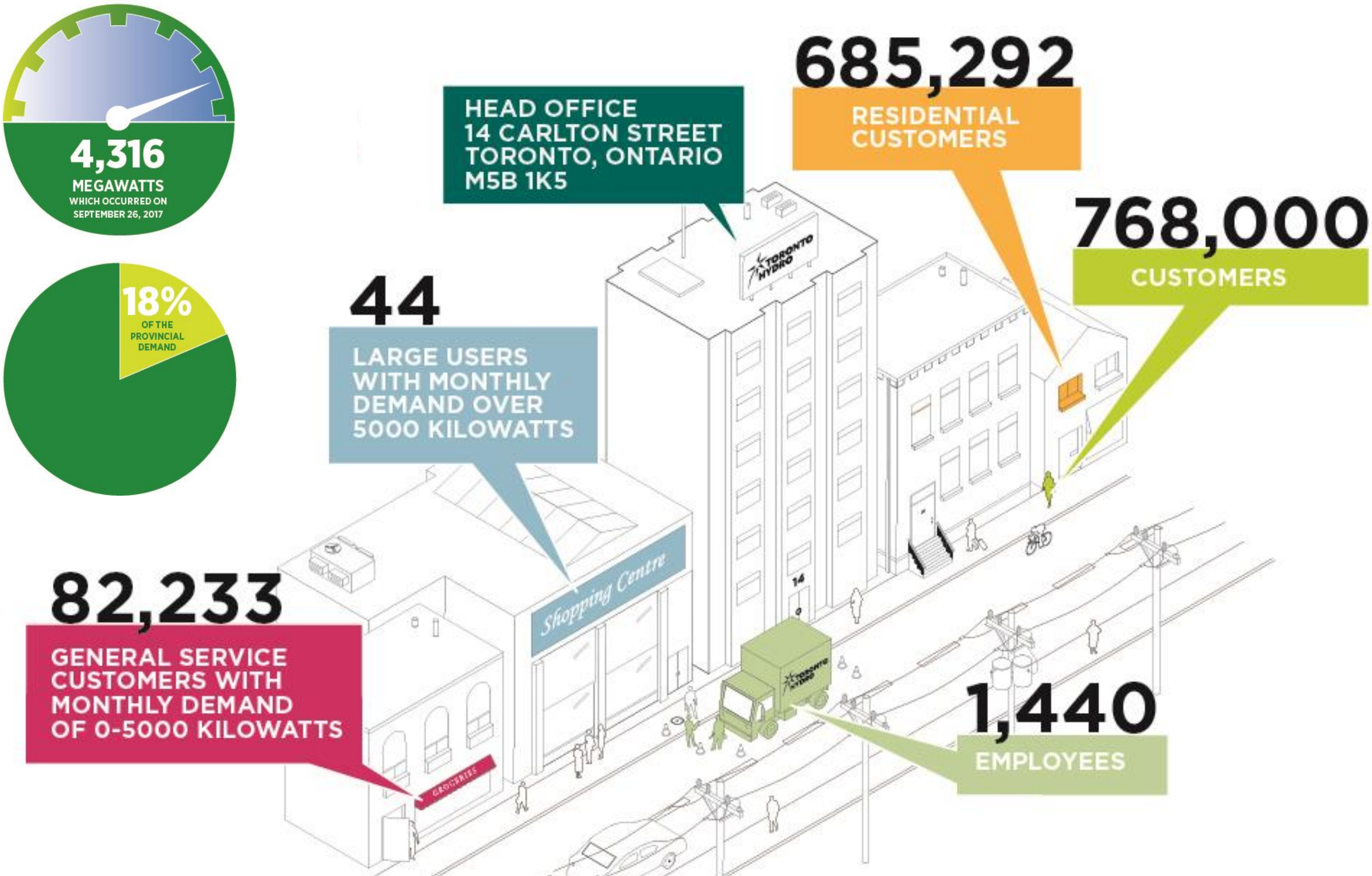
TORONTO HYDRO

DISTRIBUTION SYSTEM PLAN
2020-2024




4,316
MEGAWATTS
WHICH OCCURRED ON
SEPTEMBER 26, 2017
18%
OF THE
PROVINCIAL
DEMAND
HEAD OFFICE
14 CARLTON STREET
TORONTO, ONTARIO
M5B 1K5
685,292
RESIDENTIAL
CUSTOMERS
768,000
CUSTOMERS
44
LARGE USERS
WITH MONTHLY
DEMAND OVER
5000 KILOWATTS
82,233
GENERAL SERVICE
CUSTOMERS WITH
MONTHLY DEMAND
OF 0-5000 KILOWATTS
1,440
EMPLOYEES
Shopping Centre
GROCERIES

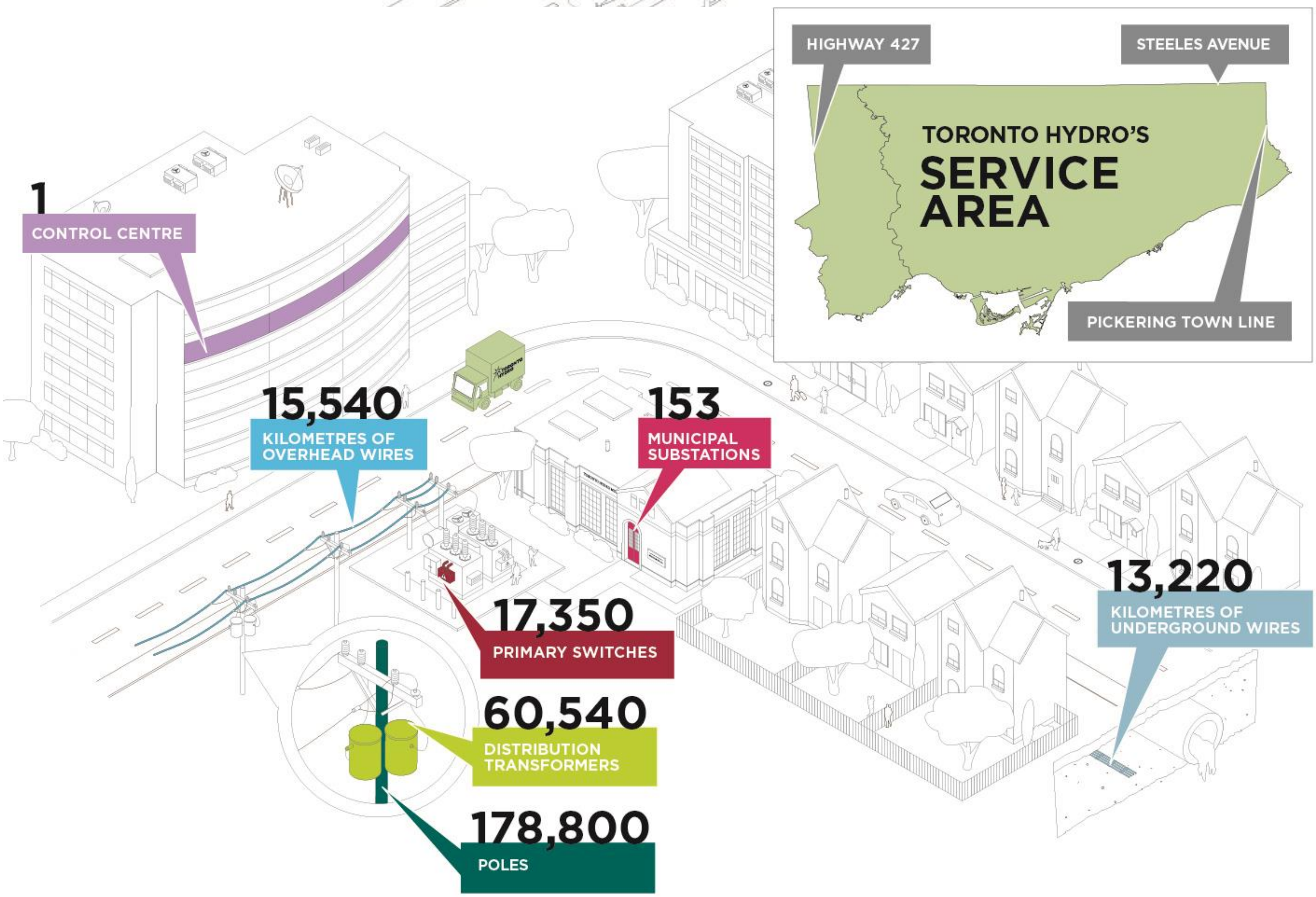

HIGHWAY 427
STEELES AVENUE
TORONTO HYDRO'S
SERVICE
AREA
PICKERING TOWN LINE
1
CONTROL CENTRE
15,540
KILOMETRES OF
OVERHEAD WIRES
153
MUNICIPAL
SUBSTATIONS
17,350
PRIMARY SWITCHES
13,220
KILOMETRES OF
UNDERGROUND WIRES
60,540
DISTRIBUTION
TRANSFORMERS
178,800
POLES

Table of Contents

Table of Contents – Detailed

A Distribution System Plan Overview

A1 Introduction

Toronto Hydro's Distribution System Plan ("DSP") provides a detailed and comprehensive view of the utility's capital investment plans and supporting information for the 2020-2024 period. The capital programs described and justified in this plan address urgent and necessary work related to the distribution system assets that safely power the City of Toronto, as well as the general plant assets that keep the utility's "24/7" operations running and responsive to customer needs and requests.

This plan continues the utility's effort to renew a significant backlog of deteriorated and obsolete assets at risk of failure, and to adapt to the continuously evolving challenge of serving, and operating within a dense, mature, and growing major city. Toronto Hydro is on track to successfully complete its previous plan for 2015-2019, with adjustments for typical changes and evolving circumstances, including the final rates approved by the Ontario Energy Board ("OEB") for that period. Efforts to date have resulted in gradual improvements to reliability, the overall age of the system, and other performance indicators.

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

The 2020-2024 DSP strikes a balance between these pressing needs and customer preferences for (i) keeping prices as low as possible, (ii) maintaining average reliability, (iii) improving reliability for customers experiencing below-average service, and (iv) balancing other priorities (e.g. customer service) with the need to contain rate increases. The resulting five-year capital expenditure plan represents the minimum level of investment needed to ensure this balance is achieved, while avoiding the accumulation of asset risk and associated declines in performance over the long-term.

Toronto Hydro developed the DSP in full accordance with Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications, and in alignment with the principles and objectives of the OEB's *Renewed Regulatory Framework* ("RRF"), including the updated guidance in the OEB's

Handbook for Utility Rate Applications (2016). In additional to the expenditure plan and forecast information for 2020-2024, the DSP provides historical and bridge year information for 2015-2017 and 2018-2019 respectively, including information on expenditures and accomplishments, material variances, and measured performance during the previous 2015-2019 plan period. In developing this DSP, Toronto Hydro built upon the experience of its first five-year DSP (covering the 2015-2019 period) and the OEB's findings in the 2015 Custom IR Application, refining successful elements (e.g. detailed investment program justifications) and making substantial enhancements to certain fundamental elements (e.g. the quality and role of Customer Engagement in planning).

A2 DSP Organization

The 2020-2024 DSP consists of the following five major sections:

- **Section A – Distribution System Plan Overview:** Provides an overview of the key elements of the 2020-2024 DSP, including brief summaries of the 2020-2024 Capital Expenditure Plan and its drivers and outcomes; the Asset Management principles, processes, and methodologies that underpin the plan; and the Customer Engagement results that informed the plan.
- **Section B – Coordinated Planning with Third Parties:** Describes how Toronto Hydro's DSP aligns with broader regional planning efforts, including information regarding the applicable consultation processes.
- **Section C – Performance Measurement for Continuous Improvement:** Provides information with respect to the selected measures that will be adopted by Toronto Hydro to track performance of the DSP over the course of the planning horizon.
- **Section D – Asset Management Process:** Describes Toronto Hydro's asset management processes, the current state of the assets and system performance challenges, and the utility's asset lifecycle optimization and risk management practices and methodologies. The processes, tools, and information in this section were used to derive the 2020-2024 Capital Expenditure Plan.
- **Section E – Capital Expenditure Plan:** Describes how Toronto Hydro leveraged various substantive inputs – including Customer Engagement findings – to develop the 2020-2024 Capital Expenditure Plan and its customer-focused objectives. This section also contains detailed justifications and business cases for the 20 capital programs that constitute the plan.[1]

A2.1 Concordance with the Chapter 5 Filing Requirements

The structure of Toronto Hydro's DSP generally concords with the headings of the OEB's Chapter 5 Filing Requirements. This concordance is summarized in Table 1 below.

[1] The vintage of asset data and station load forecasts used within the DSP are from mid-late 2017, with the exception of Asset Condition data that was updated as of January 2018.

Table 1: Concordance between DSP Sections and Chapter 5 Headings

DSP Sections	Filing Requirement Headings
Section A	5.2.1 – Distribution System Plan Overview
Section B	5.2.2 – Coordinated Planning with Third parties
Section C	5.2.3 – Performance Measurement for Continuous Improvement
Section D	5.3 – Asset Management Process
Section E	5.4 – Capital Expenditure Plan

Minor exceptions to the concordance between the Chapter 5 filing requirements and DSP headings are as follows:

- In the latest Chapter 5 requirements, issued in July 2018, the OEB relocated its filing requirements for detailed historical period data on interruptions and MEDs from Chapter 2 to Chapter 5 (section 5.2.3). Due to the timing of these updates, Toronto Hydro's direct response to these requirements remains outside the DSP in Exhibit 1B, Tab 2, Schedule 4. In addition to this stand-alone schedule, salient observations about historical reliability performance are integrated throughout the DSP, including in Section C, and are relied upon to justify forecast expenditures.
- Toronto Hydro addresses the requirements in section 5.2.4 of Chapter 5 (i.e. "Realized efficiencies due to smart meters") within the Metering capital program (Section E5.4 of the DSP).
- In the latest Chapter 5 requirements, the OEB relocated the "System capability assessment for renewable energy generation" requirements from 5.4 to 5.3. Due to the timing of these updates, Toronto Hydro's response to these requirements remains in the Capital Expenditure Plan section of the DSP (Section E3).

A2.2 Capital Programs and Drivers

The 2020-2024 Capital Expenditure Plan in the DSP consists of 20 unique capital programs. These program are allocated to each of the OEB's four major investment categories, as defined in Table 2, based on their trigger drivers, which represent the primary reason a program must be carried out.

Table 2: Capital Investment Categories

System Access	• Modifications (including asset relocation) the utility is obligated to perform to provide a customer (including a generator) or group of customers with access to electricity services via the distribution system.
System Renewal	• The replacement and/or refurbishment of system assets to extend the original serviceable life of the assets and thereby maintain the ability of the distribution system to provide customers with electricity services.
System Service	• Modifications to the system to ensure that it continues to meet operational objectives while addressing anticipated future customer electricity service requirements.
General Plant	• Modification, replacements, or additions to assets that are not part of the distribution system, including land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day to day business and operations activities.

Each capital program is defined by a single trigger driver and a number of secondary drivers. The trigger drivers for Toronto Hydro's 2020-2024 DSP programs are summarized in Table 3, below. Although safety is not listed as a trigger driver, it is a significant secondary driver for many programs – especially those that are triggered by asset Failure or Failure Risk in the System Renewal category. Secondary drivers may be as, or more, consequential than the trigger drivers. Details on the trigger and secondary drivers for each program are provided in the detailed program justifications in Sections E5 through E8 of the DSP.

Table 3: Investment Category Trigger Drivers

Category	Driver	Description
System Access	***Customer Service Requests***	• The fulfilment of Toronto Hydro's obligation to connect a customer to its system. This includes both traditional demand customers and distributed generation ("DG") customers. The obligation to connect holds as long as there are no safety concerns for the public or employees and there is no adverse effect on the reliability of the distribution system. The utility undertakes expansion or enhancements to the system when a connection cannot be made with existing infrastructure.

Category	Driver	Description
	Mandated Service Obligation	• Compliance with all legal and regulatory requirements and government directives.
System Renewal	***Functional Obsolescence***	• The asset and/or its installation is no longer aligned to Toronto Hydro's processes and practices such that it can no longer be maintained (e.g. lack of vendor support) or utilized as intended to support the utility's operations.
	Failure	• Asset or critical component failure has taken place and Toronto Hydro must respond reactively as part of its capital investment activities.
	Failure Risk	• There is imminent risk of failure due to age or condition deterioration. The potential failures will result in significant reliability impacts to customers as well as potential safety risks to crew workers or to the public.
System Service	***Reliability***	• Maintain or improve reliability at a local, feeder-wide, or system-wide level.
	Capacity Constraints	• Expected changes in load will constrain the ability of the system to provide consistent service delivery and handle demand requirements.
General Plant	***Operational Resilience***	• The ability to mitigate and recover from disruptions to core business functions.
	System Maintenance and Capital Investment Support	• Required investments to support day to day business operational activities; sustaining operations by providing its employees with a safer environment to operate in an efficient and reliable manner.

A3 Development of the 2020-2024 DSP

Toronto Hydro's 2020-2024 DSP, including the 2020-2024 Capital Expenditure Plan, was an output of its outcomes-oriented, customer-focused business planning activities. The plan was derived from the utility's distribution system asset management ("AM") processes and other operational planning activities, discussed in detail in Section D of the DSP. A high-level view of business planning as it relates to the Capital Expenditure Plan is shown in Figure 1, below.

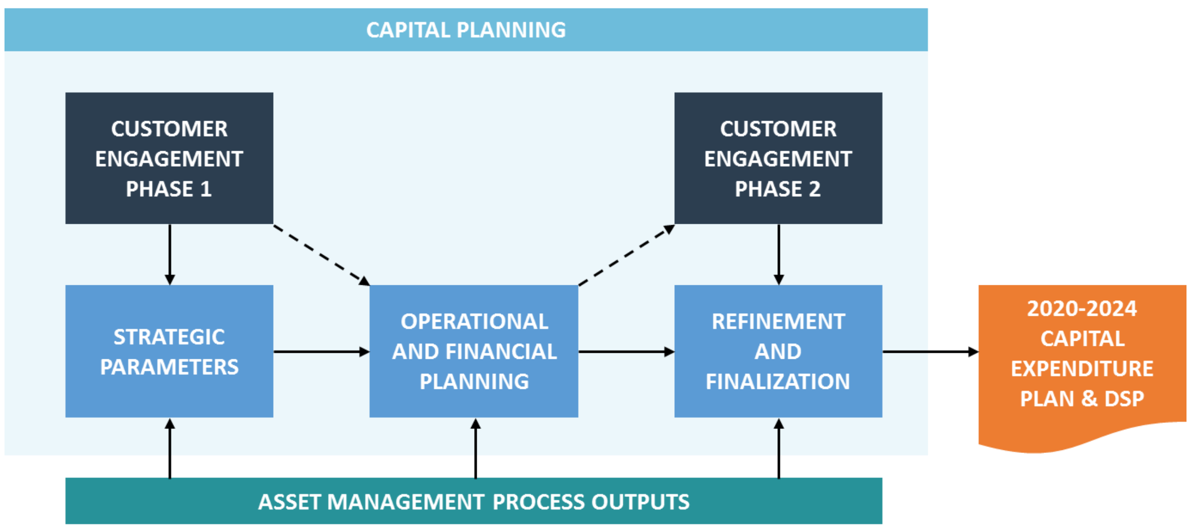


Figure 1: Capital Planning in Business Planning

Toronto Hydro began business planning by engaging customers (i.e. Phase 1 of Customer Engagement) and using the feedback received and various other qualitative and quantitative inputs to set the initial strategic parameters for the business planning horizon. These parameters included an upper price limit – reflecting most customers' preference for keeping rates as low as possible – an upper capital budget limit – approximating a minimum sustainment level of capital investment – and an Outcomes Framework that aligns with customers' priorities, the utility's corporate strategic pillars and the *Renewed Regulatory Framework*. The specifics of these parameters are discussed in detail in Section E2.

The strategic parameters guided the operational and financial planning activities that produced the Capital Expenditure Plan for 2020-2024. Over the course of these iterative planning activities, the utility worked to develop and optimize its program-level capital (and OM&A) expenditure plans to align with its short- and long-term AM objectives, while remaining within the financial constraints and considerations set-out in the strategic parameters. This exercise led to a $75 million per year reduction between the initial plan proposals and the penultimate plan.

Toronto Hydro took its penultimate plan back to customers for feedback on how effective the utility was in interpreting the Customer Engagement results and using them to inform the proposed plan. Overall, a majority of customers expressed support for either the proposed plan or doing more. Customers were particularly supportive of two programs related to preventing network vault floods and fires. The utility took this feedback into account as it made its final refinements and adjustments to the DSP.

In the result, Toronto Hydro produced an optimized and customer-aligned Capital Expenditure Plan with an average investment of $562 million[2] per year over the 2020-2024 period. The final plan produced an average annual bill impact (base rates, without riders) for residential customers of 3.0 percent for distribution, below the limit set in the strategic parameters and communicated to customers in the second phase of Customer Engagement. The program outcomes in Sections E5 through E8, as well as the Custom Performance Measures and AM objectives for the plan as whole (discussed in Sections C and E2), have been developed and calibrated to reflect customer feedback, ensuring the performance and accomplishments of the DSP are tracked over the 2020-2024 period in relation to outcomes that are meaningful to customers.

[2] This figure includes inflation and other allocations, and excludes Renewable Enabling Improvement ("REI") expenditures funded through provincial rate relief.

A4 Key Elements and Objectives of the DSP

This section provides a high-level overview of the key elements driving the level and mix of capital investment in the 2020-2024 DSP, including major system challenges, and customer needs and preferences. It also includes an overview of the outcome objectives for the 2020-2024 DSP and how Toronto Hydro intends to measure its performance in relation to these outcomes.

Figure 2 illustrates the overall level of capital expenditures planned for the 2020-2024 period, grouped by the OEB's specified investment categories. As illustrated, the largest need for capital investment continues to be in the System Renewal category, which is driven by asset failure and failure risk related to age, condition, and obsolescence.

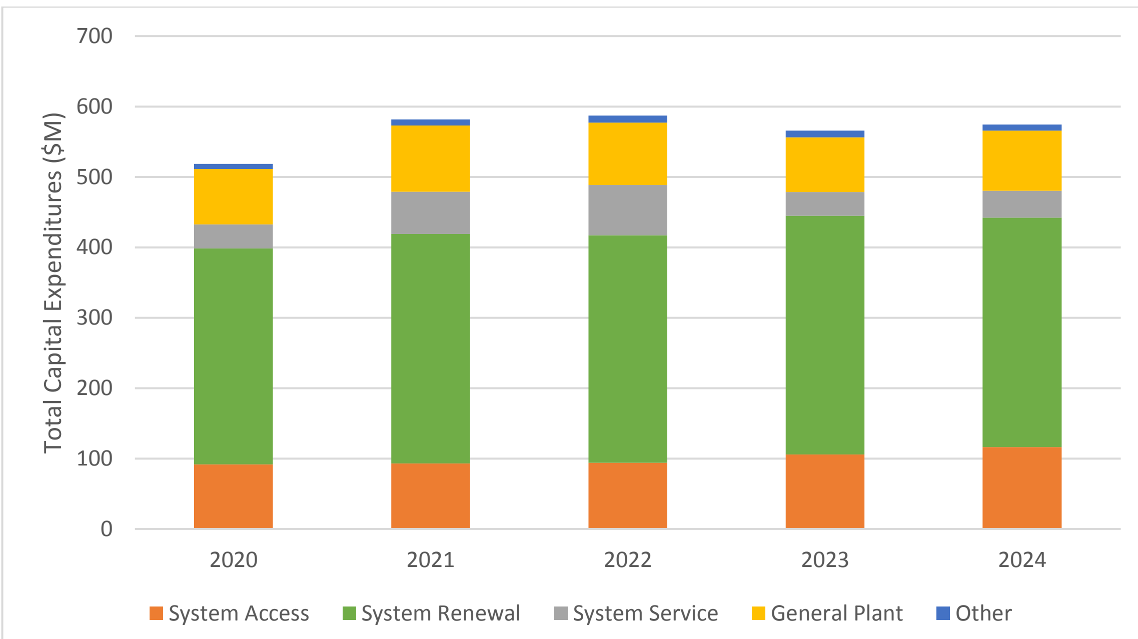


Figure 2: 2020-2024 Capital Expenditure Plan by Investment Category

A4.1 Capital Investment Needs

This section provides an overview of the system and operational investment needs facing Toronto Hydro during the 2020-2024 forecast period. For a comprehensive discussion of Toronto's existing distribution system assets, configurations, climate, and utilization please refer to Section D2.

A4.1.1 System Challenges: Deteriorating and Obsolete Assets

The most significant driver of investment in Toronto Hydro's DSP is asset failure and failure risk due to a continuing backlog of deteriorating and obsolete assets. A key system-wide indicator of the magnitude of this challenge is the percentage of Assets Past Useful Life ("APUL"). As seen in Figure 3, below, approximately a quarter of the utility's asset base is operating beyond useful life, and an estimated 9 percent will reach that point by 2025, indicating that a significant proactive renewal program is necessary to prevent this backlog from increasing. An increase in the APUL backlog would likely result in a corresponding deterioration in reliability, safety and other outcomes driven by asset failure and failure risk.

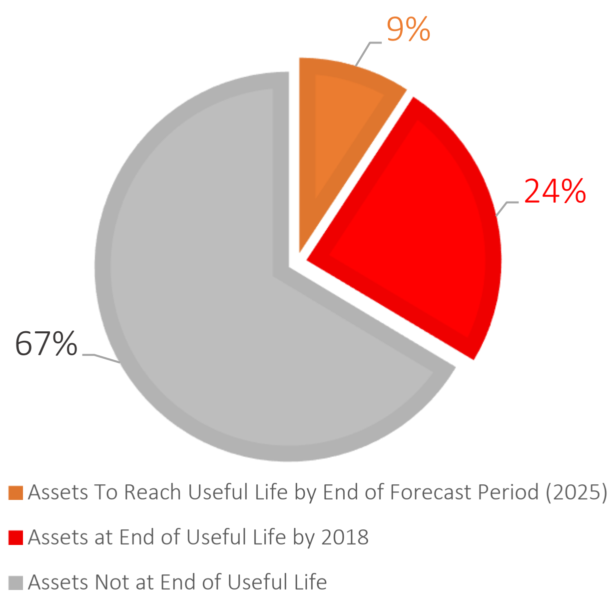


Figure 3: Percentage of Assets Past Useful Life

Asset Condition Assessment ("ACA") demographic results also indicate substantial asset investment needs for a number of critical asset classes over the plan period. Among the subset of asset classes analyzed using Toronto Hydro's ACA methodology, major civil assets like poles and vaults, which are the backbone of a safe and viable distribution system, and major stations electrical assets, which have the highest potential reliability impact on the system, are showing the greatest signs of material deterioration.

As explained in the System Renewal program justifications in Section E6, Toronto hydro is proposing a pace of renewal investment in a number of core programs that is the minimum required to prevent these age and condition-related risks from worsening over the 2020-2024 period. For instance, without the proposed proactive intervention in the overhead asset class, Toronto Hydro projects that the percentage of pole top transformers having reached or exceeded useful life will increase from 14 percent as of 2017 to approximately 40 percent by 2024, and the number of poles with material deterioration could nearly triple to over 30,000.

The utility also continues to face challenges related to higher-risk, obsolete, legacy assets, and asset configurations such as rear lot plant, box construction, non-submersible network equipment, and direct-buried cable. Legacy assets are specific asset types, configurations, or sub-systems that do not meet current Toronto Hydro standards, often featuring obsolete components with limited or no suppliers or skilled labour to support maintenance, repair, or replacement. Due to asset-specific defects or deficiencies, these assets typically carry elevated reliability, safety, or environmental risks. For example, direct-buried cable and non-submersible network protectors are highly susceptible to moisture-related damage and continue to be significant contributors to reliability and safety risk. Another example is transformers at risk of spilling PCB-contaminated oil. Toronto Hydro's pole-top and underground transformer replacement strategies for 2020-2024 are driven in part by the utility's efforts to effectively eliminate this critical environmental risk over the period.

Toronto Hydro has seen improvements in the frequency and duration of outages caused by defective equipment. However, defective equipment continues to be, by far, the largest contributor to outage frequency (i.e. SAIFI), at 36 percent, and outage duration (i.e. SAIDI), at 44 percent. In light of the age, condition, and legacy asset risks discussed above, Toronto Hydro concludes that a shift to a more reactive renewal approach would result in a decline in reliability over the short- and long-term, with potentially significant impacts for customers in areas served by legacy assets such as direct-buried cable and rear-lot plant. A reactive renewal approach would also be more costly over the long-term.

A4.1.2 System Challenges: Climate Change and Adverse Weather

On top of the reliability challenges posed by a backlog of deteriorating and obsolete equipment, Toronto Hydro anticipates that increasingly frequent adverse and extreme weather events will put additional reliability pressures on the system, making the resiliency of the system and the utility's operations a greater concern over the medium- to long-term than in past planning cycles.

Climate change is a significant factor influencing Toronto Hydro's planning and operations. By the year 2050, Toronto's climate is forecast to be significantly different than the already changing climate seen today. For example, in Toronto, daily maximum temperatures over 25°C are expected to occur 106 times per year as opposed to 66 times per year currently. Daily maximum temperatures over 40°C, which have historically been an anomaly, are projected to occur up to seven times per year by 2050.[3] A warmer climate will also allow the atmosphere to hold more moisture, which is expected to lead to more frequent and severe extreme weather events such as ice storms and extreme rainfall events. These extreme events can cause major disruptions to Toronto Hydro's distribution system.

Not only are these weather conditions projected to occur more frequently and with greater severity in the future due to climate change, but trends from the past 20 years suggest that these changes are already affecting the system. Figure 4 below depicts cumulative rainfall and the number of high wind days in Toronto over the past 20 years. With respect to rainfall, seven of the 10 highest rain fall years have occurred in the last 10 years. Similarly, six of the 10 years with the greatest number of days of wind gusts above 70 kilometres per hour have also occurred in the last 10 years.

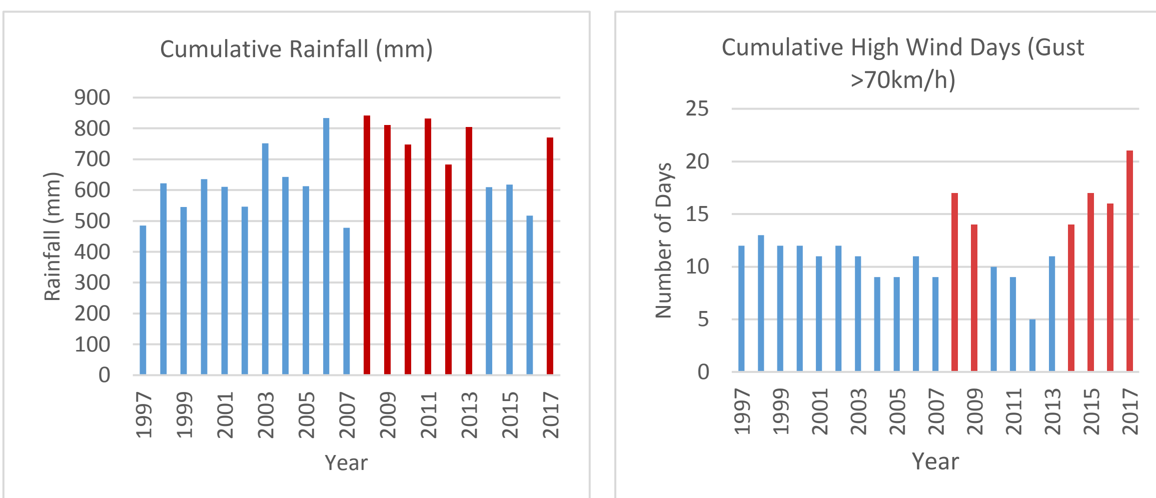


Figure 4: Cumulative Rainfall (left) and Number of High Wind Days (right) in Toronto[4]

[3] See Appendix D to Section D – Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment by AECOM (June 2015)
[4] Weather data compiled using Toronto Lester B. Pearson INTL A for January 1997 to June 2013 and Toronto INTL A for July 2013 to December 2017. Available from: Government of Canada, Weather, Climate and Hazard Historical Data online: <http://climate.weather.gc.ca/historical_data/search_historic_data_e.html>

Recent extreme weather events (see Table 4, below) have repeatedly and pervasively affected Toronto Hydro's customers. Extreme weather events in 2017 resulted in a 72 percent increase in the number of customer interruptions attributed to tree contacts compared to the average of the previous five years. Similarly, in 2018, Toronto Hydro experienced four extreme storms during the first half of the year.

These circumstances drive Toronto Hydro to continue emphasizing plans and programs that facilitate and improve its system resiliency and ability to respond to these events. This is reflected in the fact that all of the utility's investment categories include at least some investments that support this objective. System Renewal work – and especially the renewal of legacy asset types – will contribute to system hardening by improving asset health and introducing updated equipment design and construction standards that are better suited to the changing operating environment. Grid modernization efforts in the System Access,[5] System Renewal, [6] System Service,[7] and General Plant[8] categories will help the utility respond to major events more effectively. Neglecting to make these investments during the 2020-2024 period could leave the utility ill-prepared for the effects of climate change, leading to a potential decline in service and higher costs related to reactive and emergency scenarios.

Table 4: Extreme Weather Events since the Beginning of 2017

Event	Description
Freezing Rain (February 2017)	• Approximately 2-6 mm of freezing rain followed by additional heavy rain. • Estimated 9,200 customers out at peak; all customers restored within 24 hours of the start of the freezing rain event.
High-water/flooding (May - June 2017)	• Heavy rainfall in southern Ontario exceeded the yearly average for an entire summer. • Numerous incidents of high-water/flooding reported across Toronto. • No customers were directly impacted during this 55-day incident due to the utility's proactive damage assessment and DPM mitigation measures, including flood mitigation efforts.

[5] For example, replacing end-of-life meters with next-generation smart meters.
[6] For example, replacing end-of-life stations assets with assets equipped with modern SCADA-enabled remote monitoring and control capabilities.
[7] For example, installing remote sensing capabilities in network vaults to detect floods before they damage equipment.
[8] For example, creating a fully functional dual control centre (refer to Section E8.1).

Event	Description
Wind Storm (October 2017)	• Strong wind gusts approaching 100 km/h in some areas and lasting approximately 3 hours. • Estimated 43,000 customers out at peak. • 90 percent of customers restored within 11 hours of event; all customers restored within 48 hours of the end of the event.
Wind storm (April 2018)	• Sustained 65km/h winds, with gusts approaching 90km/h. • Estimated 24,000 customers out at peak; all customers restored within 48 hours of the end of the event.
Ice Storm (April 2018)	• Approximately 10-20 mm of freezing rain, 20-25 mm rain, sustained winds of 70 km/h with gusts up to 110 km/h. • Estimated 51,000 customers out at peak. • 99 percent of customers restored within first two days of response; all impacted customers restored within 5 days of the start of the event.
Wind Storm (May 2018)	• High winds reported throughout service territory with gusts reaching approximately 120 km/h. • Estimated 68,000 customers out at peak. • 96 percent of customers restored within 48 hours of the start of the event.
Flash Storm (June 2018)	• High winds reported throughout service territory with gusts reaching approximately 90-100/h. • Estimated 16,500 customers out at peak. • 86 percent of customers restored within the first 12 hours and 97 percent of customers restored within the first 24 hours of the event.

A4.1.3 System Challenges: City Growth and Capacity Constraints

By 2020, Toronto Hydro expects to be distributing electricity to approximately 768,000 customers with a peak load of 4,316 MW. This continues a steady trajectory of customer growth and it is expected to continue. Despite this growth, overall system peak load (which is temperature-dependent) has remained relatively steady in recent years at approximately 5,000 MVA. Meanwhile, Toronto continues to experience concentrated load growth in certain areas of the City, primarily due to the high number of large condominium developments. Figure 5 illustrates how this type of growth continues to outpace nearly all North American cities. This concentrated growth is mainly observed in the downtown area, but also along major transit corridors such as Yonge Street and Sheppard Avenue (and in the near future other corridors, such as Eglinton Avenue and Finch Avenue).

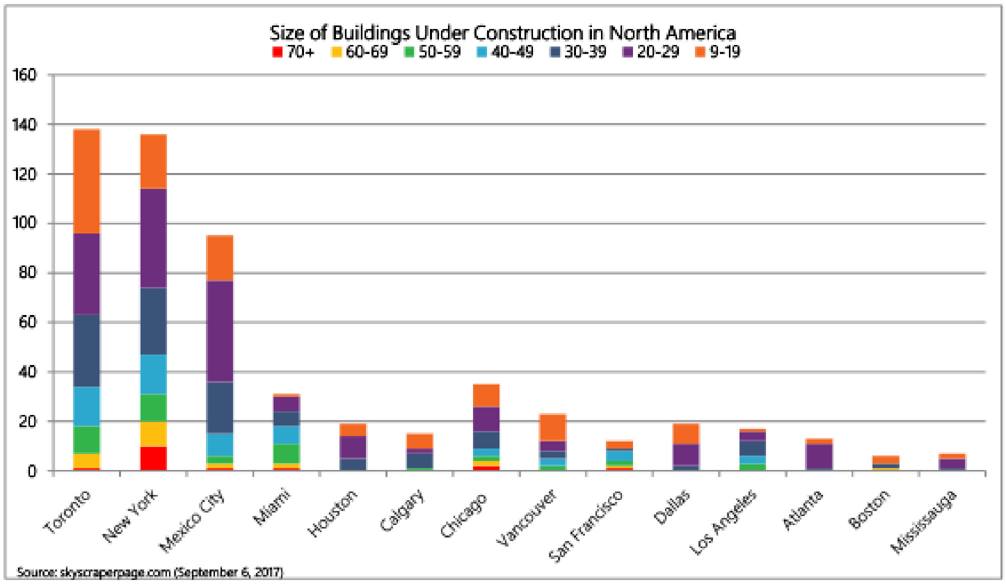


Figure 5: Number of Floors for High-Rise & Mid-Rise Buildings under Construction[9]

This growth is pushing certain distribution equipment to capacity. Infrastructure renewal and upgrades are urgently required to support that growth while maintaining reliability and safety outcomes. Investments in the System Access and System Service categories are driven by this projected level of demand. For example, Toronto Hydro projects increases in the costs associated with connecting customers and upgrading customer connections during the 2020-2024 period. Toronto Hydro must also continue investing proactively in its Load Demand (Section E5.3) and Stations Expansion (Section E7.4) programs to ensure adequate station bus capacity and feeder positions is available on the system. Failure to make these investments could have a detrimental effect on the utility's ability to connect future customers cost-effectively, without affecting reliability performance for existing customers. Furthermore, the failure to maintain and improve system operational flexibility will hamper the utility's ability to efficiently execute capital and maintenance work. Toronto Hydro's planned capacity-related investments for the 2020-2024 period are fully

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

aligned with the regional plans developed in coordination with the IESO and Hydro One as summarized in Section B, Coordinated Planning with Third Parties.

Another relevant aspect of economic growth in the City of Toronto is the number of large, third-party infrastructure renewal and expansion projects that require Toronto Hydro to relocate its existing infrastructure. Toronto Hydro is obligated by the *Public Service Works on Highways Act*[10] ("PSWHA") and section 3.4 of the Distribution System Code ("DSC") to accommodate these third-party requests in a fair and reasonable manner. For the 2020-2024 period, the utility is expecting greater needs in this area due to a larger number of committed relocation and expansion projects by Metrolinx, the Toronto Transit Commission, and the City of Toronto.

A4.1.4 System Challenges: Technology Advancement

Technology advancements are a major challenge in the electricity distribution sector globally. The challenge is in many ways greater for distributors in major urban centres. The most prominent example of that challenge may be the complexity of integrating distributed energy resources on heavily loaded feeders in dense built-out areas that serve customers sensitive to power quality.

Interest in generation projects within Toronto Hydro's service territory has been steady in recent years, and is anticipated to continue into the future. Toronto Hydro has connected approximately 1,800 distributed generation connections. The utility is regularly approached by its customers to discuss utility options for or capacity to facilitate net metering and battery energy storage. Inquiries regarding conventional generators have also increased as micro-turbine based installations become more economically viable and commercial and industrial customers attempt to increase site reliability and operational cost savings.

Toronto Hydro is obligated to facilitate the safe, timely, and cost-efficient connection of distributed energy resources to its grid, and the connection of renewable energy generation projections remains a key public policy-aligned objective. The utility's Generation Capacity and Capability Assessment (described in Section E3.3) has identified a number of potential barriers to connecting the forecasted 581 MW of incremental distributed generation anticipated by 2024, including short-circuit capacity constraints, islanding risks, and system thermal limits. Toronto Hydro's Customer Connections (E5.1), Generation Protection, Monitoring, and Control (E5.5), and Energy Storage Systems (E7.2) programs all contain necessary investments specifically targeted at connecting and facilitating distributed

[10] R.S.O. 1990, c. P-49.

energy resources. Furthermore, the utility's grid modernization efforts (e.g. proliferation of modern SCADA-enabled equipment and creation of a dual control centre), which permeate all investment categories, will help prepare the utility to manage the increasingly complex interactions and inputs in electricity generated and consumed.

While smart grid systems, infrastructure automation, and other technological advancements by Toronto Hydro and its customers offer significant opportunities, they also increase the exposure of the grid and those connected to it to greater risk of attack by hostile actors. This global challenge is particularly acute in major economic centres, such as Toronto.[11] Mitigating these technology-driven security risks is a critical and urgent challenge for Toronto Hydro in the 2020-2024 period and drives material investment in the General Plant category, including contributing to an overall increase in IT investment needs.[12]

A4.1.5 Customer Billing and Business Operations Needs

In addition to stations and feeder-level investments, Toronto Hydro must maintain its metering and non-distribution system assets to ensure accurate and timely customer billing and to keep the utility's "24/7" operations running and responsive to customer needs and requests.

Both front- and back-end assets related to customer billing are reaching end-of-life and will require replacement during the 2020-2024 period. On the front-end, this includes a necessary ramp-up in the utility's Residential and Small C&I Meter Replacement activities to address end-of-life meters with expiring seals.[13] Toronto Hydro cannot, as a matter of law, bill customers using meters with expired seals. The bulk of these meters will have their seals expire in 2024, and by 2025, 90 percent of these meters will be operating beyond their expected useful life, resulting in unacceptably high risks to billing accuracy, customer satisfaction and financial stability. To prevent these risks from materializing, Toronto Hydro must replace these meters in a staged manner beginning in 2022. Besides being a compliance-driven investment, the replacement of first generation smart meters with next generation technology will allow Toronto Hydro to capture the benefits of grid

[11] The OEB recently issued a regulatory response through its Cyber Security Framework (December 6, 2017) : <https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf>.
[12] For more information on Toronto Hydro's proposed investments to assist with cyber security, please refer to Exhibit 2B, Section E8.2, Exhibit 2B Section E8.4, and Exhibit 4A, Tab 2, Schedule 17.
[13] Refer to the Metering program (System Access) in Section E5.4 for more information and a full options analysis.

modernization capabilities such as "last gasp" functionality, which will support outage restoration, communication, and the development of customer-specific reliability measures.

On the back-end, Toronto Hydro's Customer Information System ("CIS") has been out of vendor support for over two years. The CIS is the foundation of a range of customer service functions and business processes including billing. Without vendor support, the application is increasingly exposed to reliability and cybersecurity risks, and customizations (e.g. the provision of self-service options through *mytorontohydro.com*) will continue to be challenging to administer and maintain. For these reasons, Toronto Hydro must upgrade to a fully supported CIS during the 2020-2024 period.

Beyond billing-related investments, Toronto Hydro must maintain business continuity by investing in the operational assets that allow the utility to carry-out its day-to-day business, execute work in the field, and remain responsive to customers. General Plant expenditures for 2020-2024 are largely related to routine, asset lifecycle, and condition driven investments that are necessary to ensure the safe and reliable operation of the utility's fleet, facilities, and IT infrastructure.[14]

A4.2 Addressing Customer Needs and Preferences

Toronto Hydro undertook extensive Customer Engagement as part of business planning for this application. The utility augmented its routine, ongoing customer engagement by engaging Innovative Research Group ("Innovative") to design and implement a planning-specific Customer Engagement process, which was structured in two phases.[15]

In **Phase 1**, Innovative used a range of techniques to assess customers' needs and preferred outcomes. The results of this phase directly informed the strategic parameters for the business plan and informed decision-making throughout the planning process that produced the penultimate Capital Expenditure Plan. Innovative initially identified the following customer priorities, which were foundational to the development of the utility's Outcomes Framework (described in the A4.3 below):

1) Delivering reasonable electricity prices;
2) Ensuring reliable electrical service;
3) Ensuring the safety of electrical infrastructure;
4) Providing quality customer service;

[14] Refer to Facilities Management and Security (E8.2), Fleet and Equipment (E8.3) and Information Technology and Operational Technology Systems (E8.4) programs for more information.
[15] Innovative's final report can be found at Exhibit 1B, Tab 3, Schedule 1, Appendix A

5) Helping customers with electricity conservation and efficient usage; and
6) Enabling the electrical system to support the reduction of Greenhouse gases.

After identifying and categorizing the priorities above, Innovative gathered feedback on how customers ranked these priorities. Feedback from customers was that price, reliability, and safety were their top three priorities, with lower volume and mid-size customers clearly ranking "reasonable electricity prices" as the top priority, and larger customers ranking reliability as the top concern. In Innovative's view, the overall feedback could be characterized by the following common issues:

1) Keeping distribution price increases as low as possible;
2) Maintaining long-term performance for customers experiencing average or better service;
3) Improving service levels for customers experiencing below average service or who have special reliability needs; and
4) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.

In response to this feedback, and as mentioned in Section A3 above, the utility sought to minimize rate increases by establishing an upper price limit and an upper capital budget limit that approximated the minimum sustainment level of capital investment required. Toronto Hydro used these strategic parameters and the full breadth of customer feedback to develop program-level expenditure plans that addressed customers' priorities.

Perhaps the most important example of this is how Toronto Hydro has restrained the pace of System Renewal investment to a minimum level. Customers are generally satisfied with the service they receive from Toronto Hydro, and the utility's objective for the 2020-2024 is not to deliver a step-change improvement in system-wide reliability. The utility expects that its renewal plan, in conjunction with supporting investments in other categories, can maintain current levels of system average reliability for current customers and future customers, while allowing the utility to make targeted improvements in critical performance areas such as PCB oil spill risks and worst performing feeders. Each of Toronto Hydro's System Renewal programs in Section E6 describes how this pacing has been set in relation to leading indicators of performance such as asset condition.

Toronto Hydro's plans are also responsive to other needs and preferences identified by customers, such as the power quality concerns of large customers, and the preference of most customers for improved access to usage and billing information online. For a detailed discussion of how Toronto Hydro's 2020-2024 DSP addresses customer needs and preferences, see Section E2.3.

In **Phase 2** of Customer Engagement, Innovative found that a majority of customers across all classes either supported sticking with the plan Toronto Hydro had developed or improving service (even if it cost more). Customers were asked to provide feedback on the pacing and prioritization of programs in areas where Toronto Hydro felt it could adjust pacing to achieve greater benefits. For core investments addressing safety and reliability, customers were generally supportive of the proposed pace or an accelerated approach. Customers were generally less supportive of doing more than planned when it came to more innovative investments, with the exception of investing in monitoring and control capabilities.

The utility took customers' support for the overall plan and the Customer Engagement process as confirmation that the plan achieves an appropriate balance between addressing long-term system needs and risks, delivering the outcomes that customers need and prefer, and keeping price increases as low as possible. Given the particularly strong support across customer classes for programs that address the risk of network vault floods and fires (i.e. Network Unit Renewal and Network Condition Monitoring & Control), Toronto Hydro made minor adjustments to the pace of these programs to address these issues at an accelerated pace over the 2020-2024 period.

A4.3 Outcomes and Performance Measurement

Toronto Hydro used the list of customer priorities identified in Phase 1 of Customer Engagement (summarized in A4.2 above) to develop a customer-focused Outcomes Framework for this Application and the 2020-2024 DSP. This framework aligns with both the utility's corporate strategic pillars and the outcomes and performance categories of the *Renewed Regulatory Framework* ("RRF"). The resulting framework is focused on six key outcomes: Customer Service, Reliability, Safety, Environment, Public Policy (which includes enabling the system to support the reduction of greenhouse gases), and Financial (which includes delivering reasonable electricity prices).[16]

This framework transitioned into the lens through which Toronto Hydro developed its business plan, and is reflected in the investment planning decisions made by the utility. Some of these decisions

[16] Refer to Exhibit 1B, Tab 2, Schedule 1 for more details on the structure of this framework and its alignment with the RRF and Toronto Hydro's strategic pillars.

translated into measures in Toronto Hydro's Custom Performance Scorecard for the 2020-2024 period, while others appear as priorities at the investment program level.

Toronto Hydro is proposing 15 custom measures for the 2020-2024 plan period with associated targets. These measures are shown in Table 5, below. These measures are incremental to the measures contained in the Electricity Distributor Scorecard ("EDS") and the Electricity Service Quality Requirements ("ESQR"), for a total of 44 unique measures to be reported to the OEB annually.

Table 5: 2020-2024 Custom Performance Scorecard Measures

Toronto Hydro Outcome	OEB Reporting Category	Toronto Hydro's Custom Measures	Target
Customer Service	Customer Satisfaction	Customers on eBills	Improve
Safety	Safety	Total Recorded Injury Frequency	Maintain
		Box Construction Conversion	Improve
		Network Units Modernization	Improve
Reliability	System Reliability	SAIDI - Defective Equipment	Maintain
		SAIFI - Defective Equipment	Maintain
		FESI 7 System	Improve
		FESI-6 Large Customers	Maintain
	Asset Management	System Capacity	Maintain
		System Health (Asset Condition) – Wood Poles	Monitor
		Direct Buried Cable Replacement	Improve
Financial	Cost Control	Average Wood Pole Replacement Cost	Monitor
		Vegetation Management Cost per Km	Monitor
Environment	Environment	Oil Spills Containing PCBs	Improve
		Waste Diversion	Monitor

The utility's forecasted measures and targets related to the Custom Performance Scorecard have been developed on the basis of the proposals, plans and associated rates contained in this Application. The utility selected these specific custom measures as they are strongly representative of the key drivers of expenditures during the period and customers' preferred outcomes. For example, the choice of adding SAIDI and SAIFI metrics for outages caused by Defective Equipment reflects the materiality of asset failure and failure risk as drivers of the utility's substantial System Renewal program. The target of "maintain" for these metrics reflects customers' reliability preferences for short- and long-term. Further complimenting these measures are the Feeders

Experiencing Sustained Interruptions ("FESI") measures, which have been added reflect the need to deliver targeted reliability improvements to customers experiencing below-average reliability. For a complete discussion of the utility's Custom Performance Scorecard measures, please refer to Section C of the DSP.

A4.4 Expected Sources of Cost Savings during the Plan Period

Throughout the plan period, and in the course of executing its DSP, Toronto Hydro will continue to evaluate its operational efficiencies and seek ways to reduce and avoid costs, while increasing value for ratepayers. The capital program narratives in Sections E5 through E8, and the OM&A narratives in Exhibit 4A, Tab 2, provide several examples of the investments and initiatives that will support the utility's efforts to control costs and increase productivity. The following list highlights some of these activities.

- **Grid Modernization:** Many of Toronto Hydro's planned investments in the 2020-2024 period will support the ongoing modernization of the grid, through the introduction of technologies that support remote monitoring, sensing, protection, and control. A key example of this is the Network Condition Monitoring and Control program (Section E7.3). Like all of the capital programs that introduce remote switching and monitoring capabilities, this program is expected to improve the productivity of field employees and system controllers when operating the system and responding to outages (for example, by allowing system controllers to perform switching operations remotely instead of relying on field crews for manual switching). In this program specifically, Toronto Hydro also anticipates cost savings related to network system maintenance, as the need for inspections will be reduced by the ability to monitor network vault condition remotely. The modernization of the network will also support more cost-effective customer connections by providing real-time load monitoring that will allow the utility to lift some of the connection capacity limitations on existing secondary networks. Further information on grid modernization benefits can be found throughout all investment categories, including the Metering program (Section E5.4), Stations Renewal (Section E6.6), System Enhancements (Section E7.1), and IT/OT Systems (Section E8.4).
- **Capacity Improvements:** Capacity improvements from the utility's Load Demand (Section E5.3) and Stations Expansion (Section E7.4) programs are expected to allow for more

flexibility in scheduling planned outages for maintenance at the affected stations and for the delivery of Toronto Hydro's capital plans generally.

- **Standardization:** By eliminating obsolete asset types across the system through programs such as Area Conversions (Section E6.1) and Stations Renewal (Section E6.6), Toronto Hydro expects to improve operational efficiency in a number of ways, including by improving safe and efficient employee access to the system, reducing costs associated with refurbishing and supporting non-standard assets, optimizing procurement and supply chain by reducing the number of different equipment standards on the system, and reducing line losses on 4 kV feeders. Upgrading feeders from 4 kV to 13.8 kV or 27.6 kV feeders is also expected to improve the capacity to connect customers, resulting in more cost-efficient connections.
- **Area Rebuilds:** When planning projects, Toronto Hydro uses cost-benefit and risk evaluation principles to identify opportunities to bundle multiple assets of different types into area rebuild projects. This approach reduces the risk of needing to travel and set-up in a project area on multiple occasions in a short timeframe, thereby reducing the overall cost of replacing the relevant assets and the frequency of disruption to customers. By taking this approach in programs such as Overhead System Renewal (Section E6.5) and Underground System Renewal – Horseshoe (E6.1), the utility aims to mitigate the overall cost of its System Renewal program over time.
- **Conservation First:** In addition to traditional expansion investments, the Stations Expansion (Section E7.4) program includes a continuation of Toronto Hydro's Local Demand Response activities introduced in the 2015-2019 DSP. These investments involve installing battery storage and implementing targeted demand response incentive programs to reduce peak demand by 10 MW, allowing the utility to defer an estimated $135 million of expansion investments at Cecil TS and Basin TS.
- **Safety and Environmental Costs:** Employee and public safety is paramount for Toronto Hydro and a significant driver of capital investment during the 2020-2024 period. By investing in the sustainment and improvement of safety outcomes, the utility supports secondary financial benefits, such as a decrease in Workplace Safety Insurance Board premiums resulting from the utility's safety record. For further details, please refer to Exhibit 4A, Tab 2, Schedule 15. Similarly, by endeavouring to eliminate the risk of PCB-contaminated

oil spills, Toronto Hydro reduces the risk of potentially material costs associated with non-compliance with Federal and Provincial environmental legislation and City bylaws.

- **Enhanced Work Coordination:** Some maintenance activities require an outage to be taken to create a safe work zone in accordance with Toronto Hydro's Work Protection Code. Initiatives undertaken in 2016 included the development of an annual feeder scheduling program and enhanced work coordination to allow crews to carry out more maintenance work per outage. For maintenance activities that require an outage (e.g. overhead switch maintenance), this initiative entails cost control benefits given the need for fewer switching and isolation operations overall.
- **Facilities Asset Management System:** Toronto Hydro has introduced a robust facilities management system that records assessments and maintenance plans for all assets located in Toronto Hydro's work centres and stations. This repository system identifies the condition of all facilities-related assets (e.g. poor, fair, good) owned by Toronto Hydro, ensuring that the utility is only replacing assets that are at end-of-life and in poor condition.
- **Procurement:** Toronto Hydro continues to rely on a mix of internal and external resources to carry-out its large capital and maintenance programs. The majority of the costs associated with the utility's capital work program are determined through a competitive procurement process. While labour market pressures and increasing congestion in the City of Toronto are expected to result in higher construction cost escalation during the coming years, the utility's competitive procurement strategy nonetheless helps to ensure that Toronto Hydro can secure the necessary resources to execute its capital plan at reasonable costs.

In addition to the above initiatives, Toronto Hydro's overall risk-based approach to system renewal and enhancement is expected to drive value, including cost savings, over the long-term by ensuring that decisions on when to replace assets are informed by quantitative analysis and measurement. For example, by using tools like the Feeder Investment Model ("FIM"), which provides a probabilistic, total lifecycle assessment of costs and risks, the utility is able to balance the benefits of deferring capital investments as long as possible and the additional costs (including customer interruption costs) associated with asset failure and reactive replacement. In the context of Toronto Hydro's large asset renewal backlog, economic risk-based approaches allow the utility to target assets that carry the greatest amount of risk cost based on age, condition, configuration, loading, and other considerations, ensuring that priorities are set in a manner that maximizes value-for-money over the long-term. For more information on Toronto Hydro's asset management lifecycle optimization and risk management approaches, please see Section D3.

A4.5 Third-Party Studies and Reports

The 2020-2024 DSP is supported by a several expert studies and reports.

Table 6: Third-Party Studies Filed in Support of the 2020-2024 DSP

Study	Vendor	Description/Reference
Distribution System Plan Asset Management Review	UMS Group	UMS Group was retained to review and evaluate the maturity of Toronto Hydro's asset management processes and capabilities as they relate to the formulation of the DSP. UMS Group found that Toronto Hydro "exceeds the North American average level of maturity in all areas, reaching into "Best Practice" for some." The study can be found at appendix A to Exhibit 2B, Section D.
Econometric Benchmarking of Historical and Projected Total Cost and Reliability	Power System Engineering Inc. ("PSE")	PSE was retained to apply econometric modelling to benchmark the utility's historical and projected costs and reliability. The purpose of this review was to assess the reasonableness of Toronto Hydro's revenue forecasts and inform the appropriate stretch factor in the utility's Application. PSE compared Toronto Hydro's historical and projected total costs against its benchmark costs i.e. the Toronto Hydro's expected costs in any given year based on the econometric model. PSE's results indicated that (i) the historical average total costs for the utility, from 2015 to 2017, are 18.6 percent below benchmark expectations. Specifically, Toronto Hydro's total annual costs were approximately $157 million below benchmark values in 2017; and (ii) the projected total cost levels during the 2020-2024 period are 6.0 percent below benchmark expectations. Toronto Hydro's total annual costs are expected to be approximately $32 million below benchmark values in 2024. Based on their findings, PSE states that Toronto Hydro is not a poor total cost performer and recommends a stretch factor of 0.3 percent. The study can be found at Exhibit 2A, Tab 4, Schedule 2.

Study	Vendor	Description/Reference
Unit Costs Benchmarking Study	UMS Group	UMS Group was retained to perform a capital and maintenance unit cost benchmarking exercise. The utility provided UMS with actual, all-in capitalized unit costs for major asset classes for the 2014-2016 period. UMS performed a normalized comparison of these results to those of peer utilities across North America. Overall, UMS found that Toronto Hydro performed well relative to unit cost distribution of its peers, with one asset class in the third quartile and the remainder of the asset class unit costs in the second quartile. The study can be found at Appendix B to Exhibit 1B, Tab 2, Schedule 1.
Climate Change Vulnerability Assessment	AECOM Consultants Inc.	To better understand the risks related to increases in extreme and severe weather due to climate change, in June 2015, Toronto Hydro completed a vulnerability assessment following Engineers Canada's Public Infrastructure Engineering Vulnerability Committee ("PIEVC") protocol. The assessment identified areas of vulnerability to Toronto Hydro's infrastructure as a result of climate change. Following this study, a climate change adaptation road map was developed, along with initiatives relating to climate data validation, review of equipment specifications, and review of the load forecasting model. This information informed the development of Toronto Hydro's 2020-2024 DSP. The study can be found at Appendix D to Exhibit 2B, Section D.
Standards Review – 2018 Update	Power System Engineering, Inc.	Toronto Hydro retained PSE to update its 2014 Independent Review of the utility's standard design and construction practices, major material specifications, and procedural standards processes. Toronto Hydro's revised Standards were found by PSE to be thorough, well documented, and consistent with what is seen in the industry. The study can be found at Appendix B to Exhibit 2B, Section D.

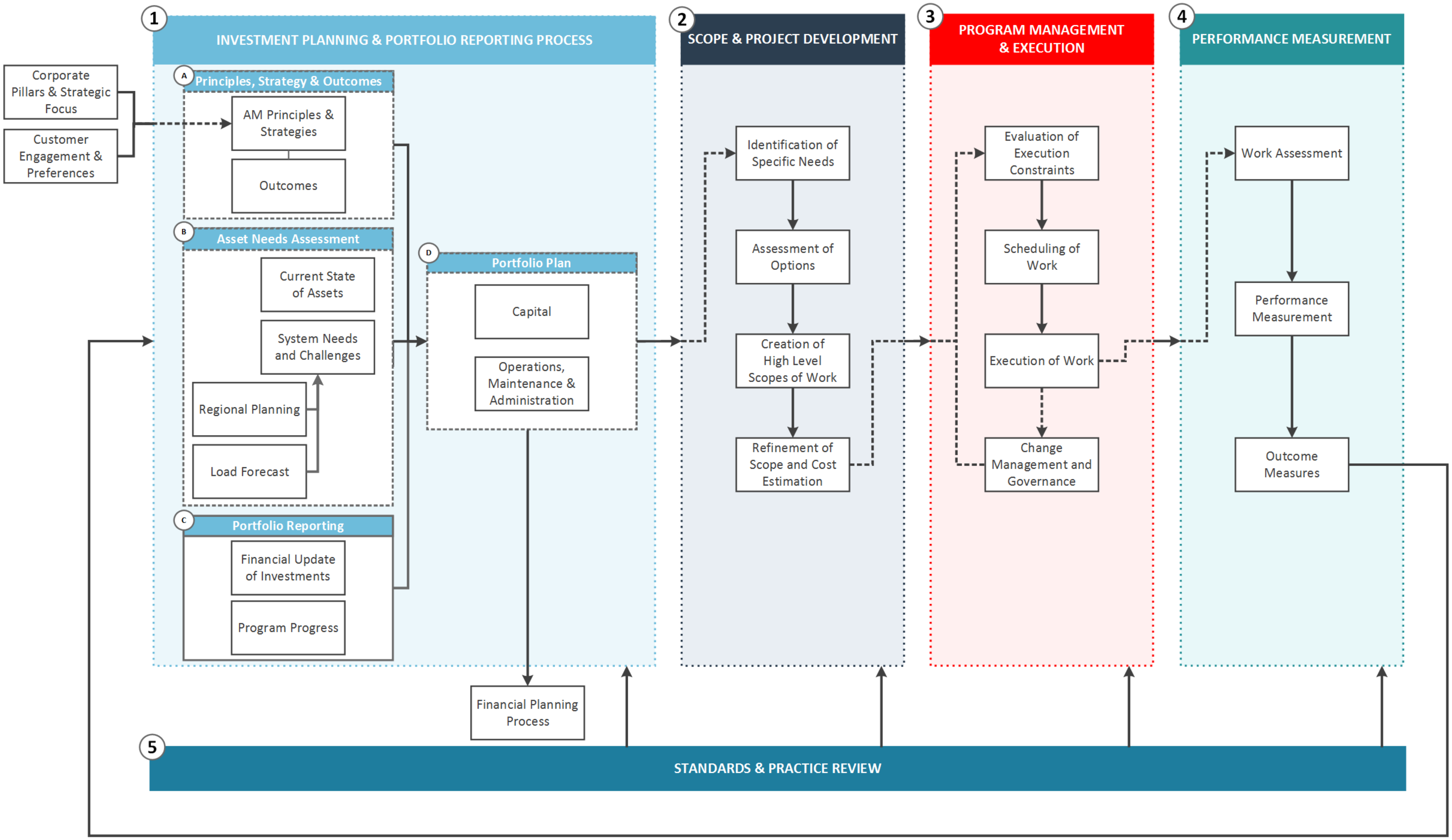
Study	Vendor	Description/Reference
IT Cost Benchmarking	Gartner Inc.	To assess the reasonableness of the utility's level of overall IT/OT expenditures, Toronto Hydro procured an independent benchmarking study by Gartner Consulting concluded that the utility's total IT expenditures per user in both 2017 and 2020 benchmark competitively against industry peers. Gartner also concluded that, in both years, the distribution of Toronto Hydro's IT investments "by cost category, investment category, and functional area are all comparable to the peer group, with some variation but no significant issues identified." The study can be found at Appendix A to Exhibit 2B, Section E8.4.
Jurisdictional review and economic case for a dual distribution control center in Toronto Hydro territory	London Economics International LLC	To assess Toronto Hydro's investment in a dual control centre, the utility retained London Economics International ("LEI") to undertake a review of comparator utilities (see Section E8.1, Appendix A). LEI completed a review of various utilities in North America that have distribution operations with more than one control centre. These facilities were fully functional and were able to take over full operational functions from the primary control centre. The review confirmed that utilities serving a critical load in North America invest in more than one fully functioning control centre to support resiliency, increase reliability, and ensure quick recovery from terrorist threats and natural disasters, for example earthquakes and floods. The study can be found at Appendix A to Exhibit 2B, Section E8.1.

A5 Asset Management Process and Enhancements

Toronto Hydro's distribution system AM Process, explained in detail in Section D and depicted in Figure 6 below. The objective of Toronto Hydro's AM Process is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders, while meeting all of the utility's mandated service and compliance obligations. This requires continuously balancing near-term customer preferences with the need to ensure predictable performance and costs over the long-term for both current and future customers.

The AM Process consists of the following five major elements which support everything from strategy and planning to construction and performance measurement.

The **Investment Planning & Portfolio Process ("IPPR")** is Toronto Hydro's system investment planning cycle, which includes both long-term and short-term planning horizons. Toronto Hydro's 2020-2024 Capital Expenditure Plan is derived from this process, which is itself built on the application of the utility's robust asset lifecycle optimization and risk management practices, described in detail in Section D3. This process produces an optimized mix of capital programs for the planning horizon, including the forecast program expenditure levels and associated volumes of work and performance objectives. The IPPR includes annual maintenance planning to support the mutual optimization of capital investment and system maintenance expenditures.



1 **Figure 6: Asset Management Process Overview**

As of 2016, the utility performs all of the activities in the IPPR on an annual basis. Toronto Hydro made this enhancement to further strengthen the alignment between: (i) the projects selected for execution within an annual capital plan; and (ii) the utility's overall five-year expenditure plan and outcome objectives. It will also help improve the sensitivity of the planning process to new and evolving information, including ongoing customer and stakeholder engagement, changes in system performance, public policy developments, and other dynamic factors.

The **Scope and Project Development** component of the AM Process involves the development of discrete projects within each investment program. This process involves four components: identification of specific needs, assessment of options, development of high-level project scopes of work ("scopes"), and refinement of scopes and cost estimates. This phase of the AM Process also relies on the application of Toronto Hydro's asset lifecycle optimization and risk management practices to ensure the development of high value projects that support the utility's outcome objectives.

The **Program Management and Execution** stage of the AM Process involves creating, delivering, and governing an executable work program. The major processes include evaluation of execution constraints, scheduling of work, execution of work, and the change management process that accounts for any required project changes.

Performance Measurement is the final stage of the AM Process. This stage monitors the performance of the investment program, to determine to what extent projects have contributed to expected outcomes. These results feedback into the annual IPPR process so that Toronto Hydro can modify programs and refine objectives if necessary.

The **Standards and Practice Review** is an ongoing activity that influences the other stages of the AM Process. It is driven by the need to evaluate particular standards and products to improve work execution. The review encompasses the necessary specifications and processes related to: (i) introducing standards and assets into the system; (ii) installation requirements; (iii) replacement considerations; (iv) identifying new assets to better meet system needs and customer preferences; (v) carrying out work in a consistent manner; and (vi) supporting improved safety on the system.

Toronto Hydro is continually monitoring and improving AM decision-support systems, enterprise systems and various inputs that support effective asset management. Recent Improvements to Toronto Hydro's AM Process over the 2015-2019 period are highlighted in Figure 7 below. For more information on these improvements, please refer to Section D of the DSP.

In addition to the distribution system AM Process, Toronto Hydro has similar robust AM processes for facilities, fleet, and IT assets. The AM approach for facilities and IT are summarized in Sections D4 and D5, while the AM strategy for fleet can found in the Fleet and Equipment capital program in Section E8.3.

New Inspection Forms
Building off the experience gained with the first iteration of the ACA (2008) and the implementation of mobile inspections (2012), Toronto Hydro completed a full review and implementation of new inspection forms to capture in greater detail, and in a more effective and standardized manner, asset conditions for distribution and stations assets.

Investment Planning & Portfolio Reporting (IPPR)
Implemented a bundled and enhanced annual planning process for reviewing and updating investment strategies and plans. This process will continue to mature throughout the 2015-2019 DSP period as Toronto Hydro gains additional experience with the enhanced outcomes framework.

Development of an Outcomes Framework
Developed and implemented a customer-focused outcomes framework that aligns Toronto Hydro's business planning processes, including IPPR, with the utility's corporate strategic pillars, the OEB's RRF outcomes, and the outcomes that ultimately matter most to Toronto Hydro customers as expressed through customer engagement.

Reliability Centered Maintenance (RCM) Updates
Completed a full review and update of Reliability Centered Maintenance analyses.

Implementation of New Analytics
Implemented new analytics (i.e. data blending and visualization) tools and a data warehouse containing data relevant to asset management and investment planning decision-making from a variety of systems across the organization (e.g. ERP, GIS, CIS, OMS, metering).

ACA Methodology Transition
To improve the quality and rigour of the ACA, including the use of condition modelling over longer-term planning horizons, the utility began a transition away from a weighted average methodology to the Common Network Asset Indices Methodology (CNAIM) – a leading approach for deriving and projecting asset health developed and adopted in the United Kingdom by the regulator (i.e. OFGEM) and distributors.

CIC Study *(ongoing)*
A Toronto-specific customer interruption cost (CIC) study is underway to engage and better understand customer reliability experiences and to obtain data for the purposes of assessing specific investments through an economic lens that includes quantified customer impacts.

Enterprise Resource Planning (ERP) System *(ongoing)*
Implementation of a new Enterprise Resource Planning (ERP) system is underway, including new Enterprise Asset Management functionality.

Freeze-Thaw Resilience Product Trials *(ongoing)*
Trials for products that can be applied to underground assets to improve freeze-thaw resistance and reduce permeability to moisture are underway, with the potential to improve reliability and extend asset life in specific applications.

ISO55000 Alignment Review *(proposed)*
Completion of an alignment review comparing Toronto Hydro's AM Process, tools, and approach to the international standard for Asset Management.

Figure 7: Recent Enhancements of the AM Process (2015-2019)

A6 Capital Expenditure Plan

Table 7 shows the level of spending for the System Access, System Renewal, System Service, and General Plant investment categories, as well as the System O&M expenditures over the historical period from 2015 to 2019 and over the forecast period from 2020 to 2024. A detailed discussed of expenditure variances and trends over the 10-year 2015-2024 period is provided in Section E4.

Table 7: Historical (2015 to 2019) and Forecast (2020 to 2024) Expenditures ($ Millions)

Category	Actuals			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
System Access	58.3	79.0	65.5	100.8	97.1	91.8	93.3	93.9	106.0	116.4
System Renewal	304.1	266.1	250.3	229.4	253.4	306.6	325.7	323.1	339.0	325.5
System Service	37.9	53.3	72.4	41.4	41.8	34.2	60.1	71.3	33.6	38.5
General Plant	79.4	109.5	98.9	70.0	40.2	78.8	93.7	89.0	77.7	85.2
Other	11.6	3.7	10.7	6.3	2.4	7.0	9.0	9.8	9.5	8.7
Total Capex	**491.4**	**511.6**	**497.8**	**447.8**	**434.9**	**518.4**	**581.8**	**587.1**	**565.7**	**574.4**
System O&M	116.1	126.5	126.3	126.9	131.0	130.4				

Tables 8 through 11, below, provide a high-level summary of the 20 capital programs that constitute the 2020-2024 DSP by investment category. Detailed analysis for each program is included in Sections E5 through E8 of the DSP, including analysis of historical expenditures and accomplishments, justifications for 2020-2024 expenditures, and options analysis.

Table 8: System Access Program Summaries

Program Index and Name		2020-2024 Cost ($M)	Summary
E5.1	***Customer Connections***	**223.4**	**Description**: Investments the utility must make to provide load and generation customers with access to its distribution system. **Objectives**: Meet mandated service obligations for customer service requests by providing new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system. **Forecast/Pacing**: Forecasted expenditures based on gross cost and customer contribution trends. Growth in residential and commercial development within the City of Toronto is expected to continue.

Program Index and Name		2020-2024 Cost ($M)	Summary
E5.2	***Externally Initiated Plant Relocations and Expansion***	**46.1**	**Description**: Work the utility must undertake to relocate its infrastructure in order to accommodate construction by third parties. In some instances, the program includes work that increases feeder capacity where efficiencies can be achieved by pairing expansion work with the required relocation work. **Objectives**: Resolve third-party relocation requests in a fair and reasonable manner. **Forecast/Pacing**: Only committed projects are included in the forecast. The utility proposes to continue the variance account for externally driven capital during 2020-2024.
E5.3	***Load Demand***	**87.5**	**Description**: Expansions, enhancements and other work to alleviate emerging connection constraints, operational constraints, and reliability risks in areas of high load demand. **Objectives**: Reduce the number of highly loaded feeders in high-growth areas to support the utility's reliability and customer service objectives and to support efficient delivery of other capital and maintenance programs. **Forecast/Pacing**: The expenditure plan reflects specific needs identified through Toronto Hydro's Distribution Capacity and Capability Assessments. See Section E5.3 for more details.
E5.4	***Metering***	**130.8**	**Description**: Various investments in customer metering infrastructure driven by legal and regulatory metering requirements and to facilitate accurate customer billing. **Objectives**: Maintain compliance with legal and regulatory metering requirements under the *Electricity and Gas Inspection Act*, the *Weights and Measures Act*, and the IESO's Market Rules. **Forecast/Pacing**: Increases in this program are mainly driven by a ramp-up in 2022 of low-volume customer meter replacement, which is required to address the end-of-life meter population.

Program Index and Name		2020-2024 Cost ($M)	Summary
E5.5	***Generation Protection, Monitoring, and Control***	**13.6**	**Description**: Eliminating connection constraints and installing monitoring and control equipment to enable the connection of forecasted distributed generation projects. **Objectives**: Enable the safe and reliable connection of all forecasted distributed generation facilities to the system (including renewable energy generation) in support of provincial public policy objectives and in alignment with mandated service obligations. **Forecast/Pacing**: Planned expenditures are based on an assessment of the enhancement investments required to safely accommodate projected distributed generation projects during the 2020-2024 period.

1 **Table 9: System Renewal Program Summaries**

Program Index and Name		2020-2024 Costs ($M)	Summary
E6.1	***Area Conversions***	**220.8**	**Description**: Conversion of two unique legacy 4.16 kV designs known as rear lot construction and box construction to updated standard 13.8 kV and 27.6 kV lines. **Objectives**: Maintain reliability, reduce the risk of long-duration outages, mitigate safety risks for employees and the public, and alleviate other customer service and operational deficiencies related to these obsolete assets through a proactive replacement strategy. **Forecast/Pacing**: Toronto Hydro has paced the program to remove all box construction by 2026, and plans to maintain the current historical pace of rear lot conversion over the 2020-2024 period by converting an estimated 2,350 customers to front lot.

Program Index and Name		2020-2024 Costs ($M)	Summary
E6.2	***Underground System Renewal - Horseshoe***	**460.3**	**Description**: (1) Neighborhood rebuilds of underground circuits consisting of high-risk direct-buried cable and other assets at risk of failure. (2) Targeted removal of transformers at risk of spilling PCB-contaminated oil. **Objectives**: Maintain reliability, continue reducing the population of high-risk direct-buried cable, and continue reducing the risk of PCB-contaminated oil spills. **Forecast/Pacing**: To meet its objectives, including maintaining pace with the rate of cable aging, the utility plans to replace approximately 215 circuit-km of the highest risk direct-buried cable, and replace transformers at-risk of spilling PCB-contaminated oil in conjunction with cable-driven rebuild projects and through spot replacements.
E6.3	***Underground System Renewal - Downtown***	**122.0**	**Description**: Proactive renewal of obsolete lead cable at risk of failure, deteriorating cable chambers, and poor performing Underground Residential Distribution equipment. **Objectives**: Maintain reliability, while preventing asset-related public and employee safety risks from accumulating, by proactively addressing the highest-risk underground assets in congested, high-traffic urban areas. **Forecast/Pacing**: To meet its objectives, the utility plans to replace the highest risk 2 percent of existing paper-insulated lead covered cable, 20 percent of asbestos-insulated lead covered cable, and an estimated 185 cable chambers or chamber roofs in deteriorating condition.
E6.4	***Network System Renewal***	**92.4**	**Description**: (1) Continue the proactive renewal of high-risk, obsolete, Automatic Transfer Switches (“ATS”) and Reverse Power Breakers (“RPB”), non-submersible network units prone to flooding, and vaults in deteriorated condition. (2) Reconfigure and re-cable sub-optimal grid networks. **Objectives**: Maintain reliability, reduce the risk of catastrophic equipment failure, support environmental objectives, and mitigate public and employee safety risks by proactively replacing deteriorating and functionally obsolete underground network system assets in highly congested urban areas. **Forecast/Pacing**: To meet its objectives, the utility plans to (1) replace all remaining ATS and RPB units in the 2020-2024 period, and (2) reduce the risk of network vault fires and flooding by replacing approximately 240 non-submersible network units by 2024.

Program Index and Name		2020-2024 Costs ($M)	Summary
E6.5	***Overhead System Renewal***	**265.7**	**Description**: (1) Neighborhood rebuilds of overheard circuits driven largely by pole condition, pole-top transformer age, feeder performance, and overall risk analysis. (2) Targeted removal of transformers at risk of spilling PCB-contaminated oil. **Objectives**: Maintain reliability, prevent asset-related failure risk from increasing, and reduce the risk of PCB contaminated-oil spills. **Forecast/Pacing**: Upwards of 34,000 poles are projected to have at least material condition by 2024. Pole-top transformers past useful life are projected to increase from 14 percent to 40 percent. The utility plans to meet its objectives by replacing approximately 13,000 poles in this program between 2018 and 2024 and by targeting transformers at risk of spilling oil with PCB.
E6.6	***Stations Renewal***	**141.5**	**Description**: Proactive replacement of critical transformer station (“TS”) and municipal station (“MS”) assets at risk of failure. **Objectives**: Maintain reliability, improve system resiliency, and reduce safety and environmental risks by addressing the increasing backlog of critical stations assets that are in deteriorating condition, beyond useful life, and otherwise at risk of failure. **Forecast/Pacing**: The program addresses a variety of major stations assets at a pace intended to maintain or improve the level of failure risk associated with each asset type population, as indicated by condition scores and observations, age, criticality, obsolescence, and other considerations.
E6.7	***Reactive and Corrective Capital***	**317.2**	**Description**: (1) The urgent and non-discretionary replacement of failed assets and assets with high-risk deficiencies. (2) Targeted, corrective interventions on worst performing feeders. **Objectives**: (1) Maintain reliability and mitigate immediate safety and environmental risks by addressing failed and critically defective assets in a timely manner. (2) Prevent increases in the number of feeders experiencing especially poor reliability by monitoring and executing short-term improvements on worst performing feeders where feasible. **Forecast/Pacing**: Due to the continuing backlog of aging, poor condition and obsolete assets, and the increasing frequency and intensity of adverse weather events and conditions, Toronto Hydro is forecasting moderate increases in the expenditures in this program in 2020-2024.

1 **Table 10: System Service Program Summaries**

Program Index and Name		2020-2024 Costs ($M)	Summary
E7.1	***System Enhancements***	**27.7**	**Description**: Targeted contingency enhancements to reduce the impact of asset failures and other outage causes, including adding tie-points to feeders, installing remote switching points, and installing protection equipment upstream from customer-owned stations equipment. **Objectives**: Maintain current levels of reliability while improving system resiliency in the face of increasingly frequent adverse weather events. **Forecast/Pacing**: Toronto Hydro is scaling back on the pace of investment in this area in 2020-2024 in light of progress already made in 2015-2019 and to reflect customer preferences for maintaining current levels of reliability.
E7**.2**	***Energy Storage Systems***	**10.5**	**Description**: Installing battery storage systems in targeted locations to enable renewable generation connections, support grid performance, and facilitate customer-specific battery solutions. **Objectives**: Support the utility's objectives of connecting renewable generation projects and improving grid performance (e.g. power quality) in poor performing areas. **Forecast/Pacing**: Forecast renewable enabling energy storage projects are based on anticipated connection constraints in the 2020-2024 period. A modest grid performance energy storage plan will be prioritized based on a needs and benefits analysis of specific feeder segments. Toronto Hydro is also planning to offer customer-specific battery storage solutions in accordance with "beneficiary pays" principles.

Program Index and Name		2020-2024 Costs ($M)	Summary
E7.3	***Network Condition Monitoring and Control***	63.0	**Description**: Modernizing the network system by installing SCADA-enabled monitoring and control technology throughout the network system. **Objectives**: Supports multiple objectives, including maintaining reliability, improving the resiliency of the network system in the face of increasing flooding risk, preventing vault fires and related safety and environmental risks, improving outage restoration capabilities, reducing network maintenance costs, and improving the utility's ability to connect new customers to the network system. **Forecast/Pacing**: Toronto Hydro forecasts 90 percent coverage of the network system with SCADA enabled monitoring and control capabilities by 2024 – an objective that received strong support from customers in Customer Engagement.
E7.4	***Stations Expansion***	136.4	**Description**: Expansion and demand response investments to mitigate capacity constraints at the station level. **Objectives**: Ensure sufficient system capacity is available to maintain reliability, connect customers, and support efficient operations, while deferring expansion investments through demand response initiatives where appropriate. **Forecast/Pacing**: The 2020-2024 proposed investments are informed by, and fully align with, Integrated Regional Resource Plan (IRRP) activities conducted in coordination with the IESO and Hydro One. Overall, Toronto Hydro is investing what is necessary prevent system capacity from deteriorating over the 2020-2024 period.

1 **Table 11: General Plant Program Summaries**

Program Index and Name		2020-2024 Costs ($M)	Summary
E8.1	***Control Operations Reinforcement***	40.2	**Description**: Create a fully functional dual control centre at a separate physical location from the existing primary control centre. **Objectives**: Improve Toronto Hydro's operational resiliency, including the utility's ability to safely operate the distribution grid in emergency scenarios, in line with industry practices for utilities serving a critical load. **Forecast/Pacing**: Toronto Hydro plans to install and operationalize this dual control centre during the 2020-2024 period.

Program Index and Name		2020-2024 Costs ($M)	Summary
E8.2	***Facilities Management and Security***	**60.4**	**Description**: Condition-based investments and improvements to physical security at critical operating centres and stations buildings. **Objectives**: Support all DSP outcomes by maintaining infrastructure that supports critical operations of the distribution system and ensuring safety and business continuity by improving security at operation centres. **Forecast/Pacing:** 2020-2024 investments in this program are largely driven by lifecycle cost and risk minimization principles informed by asset condition information and studies. Increases in this program are driven by required investments in deteriorating stations buildings and necessary upgrades to security systems.
E8.3	***Fleet and Equipment Services***	**42.5**	**Description**: Routine investment in the utility's fleet of vehicles to maintain safe and reliable operation in accordance with lifecycle cost optimization principles. **Objective**: Minimize vehicle downtime, repairs, and safety risks by cost-effectively investing in a reliable fleet of vehicles. **Forecast/Pacing**: The program is paced to address light and heavy duty vehicles that will be due for replacement during the 2020-2024 plan period in accordance with lifecycle optimization analysis. Toronto Hydro will assess vehicle condition before taking any vehicle out of service. Over the 2020-2024 period, Toronto Hydro will replace a higher number of heavy duty vehicles, as compared to the 2015-2019 period, due to their age and condition.

Program Index and Name		2020-2024 Costs ($M)	Summary
E8.4	***IT/OT Systems***	**281.4**	**Description**: Replacing and upgrading information and operational technology in accordance with the utility's IT Asset Management strategy and methodologies. **Objectives**: Support Toronto Hydro's business functions and priorities, including effective and reliable service to customers, safe and efficient management and operation of the distribution system, compliance with legal and regulatory requirements, and sustainment of the utility's long-term financial viability, by making necessary and targeted investments in core IT/OT infrastructure, while keeping related costs in alignment with industry norms. **Forecast/Plan**: Increased investment in the 2020-2024 period is driven by overall hardware and software needs, including replacement of end-of-life and unsupported assets, and enhancements necessary to adapt to evolving risks, regulatory requirements, and customer needs and preferences. A study performed by Gartner confirmed that the utility's overall IT costs, including by category and function, are competitive and comparable its peer group.

B Coordinated Planning with Third Parties

B1 Overview of Coordinated Planning Approach

Toronto Hydro participates in infrastructure planning on a regional basis to ensure regional issues and requirements are effectively integrated into the utility's planning processes. Toronto Hydro participates in the planning processes that produce the Toronto Region Integrated Regional Resource Plan ("IRRP"), led by the Independent Electricity System Operator ("IESO"), and in the Regional Infrastructure Plans ("RIP") for the Metro Toronto Region and Greater Toronto Area ("GTA") North Region, led by Hydro One Networks Inc. ("Hydro One"). Toronto Hydro's Distribution System Plan ("DSP") has been informed by the results of the completed regional plans and continues to coordinate with the aforementioned parties with respect plans that are under development. The following sections describe the coordinated planning approach, results from the ongoing Regional Planning Process, and the IESO's comments on the DSP's proposed renewable energy generation ("REG") investments.

B1.1 Coordinated Planning Approach

Planning for the electricity system in Ontario is generally done at three levels:

- Bulk system planning;
- Regional system planning; and
- Distribution system planning.

These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Bulk system planning typically looks at the broader power system. The bulk power system transfers large quantities both within Ontario (as between major generation sources and load centres) as well as between the provincial grid and neighbouring power systems external to the province via the interconnections. The IESO has accountability for the integrated planning of the bulk power system.

Regional planning looks at supply and reliability issues at regional and local levels, largely considering portions of the power system that supply various parts of the province. There are portions of the power system which can be electrically grouped together due to their bulk supply points and their electrical inter-relationships whereby common facilities may impact many connected customers.

Regional planning focuses on the facilities that provide electricity to transmission connected customers such as distributors and large directly-connected customers. This typically includes the transformer stations supplying the load and the transmission supply circuits to these stations. It also includes the 115/230 kV auto-transformers and their associated switchyards. From a resource perspective, regional planning considers local generation and Conservation and Demand Management ("CDM") that could be developed to address supply and reliability issues in a region or local area.

Local Distribution Companies ("LDCs") conduct wires (and resource) planning at the distribution level and coordinate with the Transmitter and the IESO mainly on transmission supply facilities. Toronto Hydro has coordinated new or enhanced transmission supply facilities for some of its stations. These are discussed in more detail in Section B2.

Regional planning can overlap with bulk system planning and distribution system planning. Overlaps with distribution system planning occur largely at the transformer load stations which deliver power to distributors, and at large directly-connected customers. Planning for the construction of transformer load stations, can sometimes take place at the distribution level. Another example where regional planning may require coordination with distribution planning occurs when a distribution solution may address the needs of the broader local area or region, for example, by providing load transfer capability between transformer stations.

Toronto Hydro consults with various stakeholders as part of the Regional Planning Process. Sections B1.2 to B1.5 describe the key stakeholder consultations within this process. Section B2 describes the process itself.

B1.2 Customer Consultations

The Regional Planning Process includes the formation of a Local Advisory Committee ("LAC"), led by the IESO. The IESO invited the City of Toronto, First Nations, and Métis communities, stakeholders, community groups and the general public to provide input on the development of the plan. In all, there are 18 members of the Toronto LAC. The inaugural meeting occurred in January 2016, and as of December 2017, six meetings have been held. Details, including meeting summaries, can be found at the following IESO link:

- http://www.ieso.ca/get-involved/regional-planning/gta-and-central-ontario/central-toronto-engagement

B1.3 Transmitter Consultations

Toronto Hydro consults with Hydro One through IRRP and RIP; the latter is led by Hydro One.

The Metro Toronto RIP, that covers Toronto Hydro's service area, was completed in January 2016 and is discussed in section B2.2 below. The GTA North RIP, that covers a neighbouring region important to Toronto Hydro's operations, was completed in February 2016 and is discussed in Section B2.3 below.

Hydro One launched a new RIP cycle in June 2017, starting with a Needs Assessment update. The Toronto Region Needs Assessment Report was completed in October 2017, and is provided as Appendix A.[1]

B1.4 Other Distributor Consultations

Toronto Hydro is not an embedded LDC, and does not supply any embedded LDCs. Therefore, the utility's planning consultations with other LDCs typically occur in the context of regional planning.

B1.5 IESO Consultations

Toronto Hydro actively consults with the IESO as part of Integrated Regional Resource Plan ("IRRP"). The most recent IRRP was published in 2015 and updated in 2017. The status of this plan is discussed in Section B2.1 below. The IESO launched a new IRRP process for the Toronto Region in the spring of 2018. Toronto Hydro is the host distributor for that IRRP and is actively consulting with the IESO, Hydro One and the public.

[1] The GTA North Region Needs Assessment was completed in March 2018 and is provided in Appendix B, and discussed in Section B2.3.

B2 Regional Planning Processes

The regional planning process is an important input to distribution system planning and the regional planning process is informed by Toronto Hydro's plans. The regional planning process for Toronto is characterized by:

- a large load that is dynamic in the city area;
- a significant number and density of transmission lines and stations;
- the presence of large generation; and
- a customer base that has experienced, and is sensitive to, major events that disrupt continuity of service.

To facilitate infrastructure planning, the IESO divides Ontario into planning regions. As planning considerations change, the boundaries of these regions are revised. In recent years, Toronto Hydro's service area was split between Central Toronto and Northern Toronto. Metro Toronto was also a descriptor of the planning region. More recently, regional planning considers Toronto Hydro Service area, the City of Toronto on a consolidated basis: the Toronto Region. Planning documents and reports that have been developed, issued, and relied upon during the 2015-2018 period, and that inform the utility's plans, make refer to the region using these various names.

B2.1 Toronto Integrated Regional Resource Plan

The Toronto Region used to be divided into two sub-regions for ease of planning: Central Toronto and the Northern sub-regions. The IRRP currently in development pertains to the Toronto Region. The IESO is the lead, working with Hydro One (the transmitter and Toronto Hydro (the sole LDC).

The purpose of the IRRP is to ensure that the electricity service requirements of the central Toronto community are served by an appropriate combination of demand and supply options that reflect the priorities of the community. Planning activities include forecasting the expected growth in electricity demand for 25 years, investigating the costs and benefits of conservation, distributed generation, and transmission and distribution options in meeting the future electricity needs of customers in the central Toronto area**.** The result of the planning process is an integrated plan, with a long-term perspective, which recommends a balance of options that account for costs, reliable electricity service, and mitigation of environmental impacts. The plan was completed in April 2015, and an

Addendum to the IRRP was completed in February 2017. The impact of the regional plan on the DSP is discussed in Section E2.2.3.3. An IESO link to the IRRP is provided below:

- http://www.ieso.ca/en/get-involved/regional-planning/gta-and-central-ontario/central-toronto-sub-region

The regional planning cycle is underway for the Toronto Region and an IRRP is expected to be posted in the fall of 2019.

B2.2 Metro Toronto Regional Infrastructure Plan

The Metro Toronto RIP was completed in January 2016. The plan is provided as Appendix C.[2]

The plan was the final phase of the regional planning process following the completion on the Central Toronto Sub-Region's IRRP by the IESO in April 2015 and the Metro Toronto Northern Sub-Region Needs Assessment Study by Hydro One in June 2014.

The Metro Toronto RIP provides a consolidated summary of needs and recommendations for Toronto over the near- and mid-term (five to ten years). The impact of the Metro Toronto RIP on the DSP is discussed in Section E2.2.3.3.

In response to the IRRP process that restarted earlier that year, in June 2017, Hydro One began the process of updating with the Needs Assessment, which will support the next IRRP and RIP. The Needs Assessment Report was completed in October 2017 and can be seen at the following link:

- https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/Needs%20Assessment%20-%20Toronto%20Region%20-%20Final.pdf

B2.3 GTA North Regional Infrastructure Plan

The GTA North Regional Infrastructure Plan (RIP) was completed in February 2016. The plan is attached as Appendix D.[3]

[2] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/RIP%20Report%20Metro%20Toronto.pdf

[3] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtanorth/Documents/Needs%20Assessment%20Report%20-%20GTA%20North%20Region.pdf

The RIP was the final phase of the regional planning process for the GTA North Region which consists of the York Sub-Region and the Western Sub-Region. It followed the completion of the York Sub-Region Integrated Regional Resource Plan by the IESO in April 2015 and the Western Sub-Region Needs Assessment Study by Hydro One in June 2014. Because Toronto Hydro also receives supply from GTA North Region, Toronto Hydro is a participant of the process.

Participants of the RIP included:

- Enersource Hydro Mississauga Inc.;
- Hydro One Brampton Networks Inc.;
- Hydro One Networks Inc. (Distribution);
- Independent Electricity System Operator;
- Newmarket-Tay Power Distribution Ltd.;
- PowerStream Inc.; and
- Toronto Hydro.

Toronto Hydro provided input to the GTA North Western Sub-Region Needs Assessment. The purpose of the Needs Assessment report is to assess if there were regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a "wires" only solution is necessary, such needs will be addressed between the relevant LDCs and Hydro One and other parties as required. No need for coordinated regional planning was identified. Impacts to the DSP are described in Section E2.2.3.3.

Hydro One launched a new GTA North regional planning cycle in December 2017, starting with a Needs Assessment update. The Needs Assessment Report for the GTA North Region was finalized in March of 2018, is provided in Appendix B, and is available at the link below:

- https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtanorth/Documents/Needs%20Assessment%20Report%20-%20GTA%20North%20Region.pdf

B3 IESO Comments on Renewable Energy Generation

B3.1 IESO Comment Letter

In compliance with section 5.2.2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (2018),[4] Toronto Hydro formally requested a letter of comment from the IESO with respect to the utility's planned renewable energy generation ("REG") investments. Toronto Hydro received the IESO Letter of Comment on July 20, 2018. This letter can be found in Appendix E to Section B.

B3.2 Toronto Hydro's Response to IESO Letter

The IESO found that Toronto Hydro's REG investment plan is substantially consistent with the IESO's information regarding REG applications to date and that the investments in Toronto Hydro's plan support and enable the connection of additional REG.

The IESO also confirmed that an IRRP is currently underway for the Toronto Region to be completed in 2019, and that following the IRRP completion, Hydro One is expected to conduct an RIP.

The IESO also found that although Toronto Hydro's plans are not included within the most recent RIP, the utility's plans to address barriers to connect additional DG within Toronto Hydro's service area is consistent with regional planning principles; and that the IESO does not foresee a need for coordination with other parties other than Hydro One.

[4] Previously, section 5.1.4.2 of the OEB's *Filing Requirements for Electricity Transmission and Distribution Applications (2013).*

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Toronto Region

Date: October 18, 2017

Prepared by: Toronto Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Toronto Region and to recommend which needs may require further assessment and/or regional coordination to develop wires options. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

The Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION	Toronto (formerly Metro Toronto)		
LEAD	Hydro One Networks Inc. (“HONI”)		
START DATE	June 26, 2017	**END DATE**	October 18, 2017

1. INTRODUCTION

The first cycle of the Regional Planning process for the Toronto Region was initiated in Q2 2014 and completed with the publication of the Regional Infrastructure Plan (“RIP”) on January 12, 2016. The RIP provided a description of needs and recommendations of preferred wires plans to address near-term and mid-term needs that may emerge over the next ten years. The RIP also identified some long-term needs that will be reviewed during this planning cycle.

The purpose of this Needs Assessment is to identify any new needs and reaffirm needs identified in the previous Toronto Region RIP.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. The trigger for this NA was several new needs emerging in the Toronto Region as discussed in this report.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Toronto Region and includes:

- New needs identified by Study Team members; and,
- Review and reaffirm needs/plans identified in the previous RIP

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment (“SA”), Integrated Regional Resource Plan (“IRRP”) and RIP, based on updated information available at that time.

An updated load forecast for the region was provided by Toronto Hydro-Electric System Limited (“THESL”) for the purposes of this NA. In addition, THESL is currently undertaking a study to develop a new load forecast, expected to be completed by Q4 2017. The updated load forecast will be taken into account during the next phases of regional planning, i.e. IRRP and/or RIP. Hydro One Distribution, Alectra Utilities, and Veridian reaffirmed their load forecast developed during the RIP phase and the Study Team deemed this to be adequate for this NA.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies (“LDC”), the Independent Electricity System Operator (“IESO”), and Hydro One provided input and relevant information for the Toronto Region regarding capacity needs, system reliability, operational issues, and major assets/facilities approaching end-of-life (“EOL”).

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the study period. The assessment reviewed available information including load forecasts, system reliability and operation issues, and major high voltage equipment identified to be at the end of their useful life and requiring replacement/refurbishment.

A technical assessment of needs was undertaken based on:

- Station capacity and transmission adequacy;
- System reliability and operation; and,
- Major high voltage equipment reaching the end of its useful life with respect to replacing it with similar type equipment versus other options to determine the most optimal, resilient, and economic outcome.

6. RESULTS

I. Aging Infrastructure

In the Toronto Region, high voltage equipment at 13 stations and 3 transmission line sections have been identified to be at the end of their useful life and require replacement/refurbishment in the near and medium term. Refer to section 7.1.1 for more details.

II. 115kV Connection Capacity

A transformation capacity need to serve the potential load growth in the East Harbor / Port Lands area has been identified in the medium term. A transformation capacity need for Basin TS was also identified in the medium term. It is forecasted to slightly exceed its LTR in 2027. Refer to section 7.1.2 for more details.

III. System Reliability & Operation

Load restoration needs for the loss of circuits, C14L+C17L, C5E+C7E, and K3W+K1W have been identified. Refer to section 7.1.3 for more details.

IV. Needs Identified in Previous Toronto Region RIP

The study team reaffirms that the needs and their respective plans identified in the previous Toronto Region RIP (which are not yet underway) are still valid. Updates to the plans have been provided where relevant. Refer to sections 7.2.1 to 7.2.9 for more details.

7. RECOMMENDATIONS

The Study Team's recommendations are as follows:

a) Hydro One and THESL will coordinate a plan to address the following needs (further regional coordination is not required):

- EOL assets discussed in section 7.1.1.1 and 7.1.1.2

b) Further regional coordination is required for the following needs:

- EOL assets discussed in section 7.1.1.3 (EOL equipment replacement at Bermondsey TS, John TS, Main TS, and Manby TS) and 7.1.1.4 (EOL equipment replacement for C5E/C7E, H1L/H3L/H6LC/H8LC, and L9C/L12C)
- Additional transformation capacity need in the East Harbor / Port Lands area and Basin TS transformation capacity need discussed in section 7.1.2
- Load restoration need for the loss of circuits C14L+C17L, C5E+C7E, and K3W+K1W, discussed in section 7.1.3.
- Needs identified in previous Toronto RIP/IRRP (mostly the long term needs), discussed in sections 7.2.5 to 7.2.9 (transformation capacity need for 230/115kV Leaside autotransformers and voltage collapse of 115kV Leaside subsystem; line capacity need for 115kV Leaside TS x Wiltshire TS corridor; transformation capacity need for 230/115kV Manby TS autotransformers; line capacity need for 115kV Manby West x Riverside Junction; and, line capacity need for 115kV Don Fleet JCT x Esplanade TS)

c) The Study Team reaffirms the remaining needs that were identified in the previous RIP, discussed in sections 7.2.1 to 7.2.4. Their associated plans are valid and are in progress.

TABLE OF CONTENTS

List of Tables and Figures

1 INTRODUCTION

The first cycle of the Regional Planning process for the Toronto Region (formerly Metro Toronto) was completed in January 2016 with the publication of the Regional Infrastructure Plan (“RIP”). The RIP provided a description of needs and recommendations of preferred wires plans to address near and medium term needs. The long term needs were recommended for further review during the next regional planning cycle.

The purpose of this Needs Assessment (“NA”) is to identify new needs and reconfirm the needs identified in the previous Toronto Region regional planning cycle. Since the first regional planning cycle, several new needs in the region have been identified. The majority of these needs are a result of aging infrastructure which need to be replaced within the near to medium term.

This report was prepared by the Toronto Region Technical Study Team (“Study Team”), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. The report captures the results of the assessment based on information provided by the lead transmitter, Local Distribution Companies (“LDC”) and the Independent Electricity System Operator (“IESO”).

Table 1: Toronto Region Technical Study Team Participants

Company
Alectra Utilities Corporation (formerly Enersource Hydro Mississauga, PowerStream Inc.)
Hydro One Networks Inc. (Distribution)
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator (“IESO”)
Toronto Hydro-Electric System Limited (“THESL”)
Veridian Connections Inc. (“Veridian”)

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. The NA was triggered due to several new needs in the Toronto Region as discussed in this report.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Toronto Region and includes:

- New needs identified by the Study Team; and
- Needs already identified in the RIP report or IRRP report

The Study Team may identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), Integrated Regional Resource Plan ("IRRP"), and/or RIP.

An updated load forecast for the region was provided by Toronto Hydro-Electric System Limited ("THESL") for the purposes of this NA. In addition, THESL is currently undertaking a study to develop a new load forecast, expected to be completed by Q4 2017. The updated load forecast will be taken into account during the next phases of regional planning, i.e. IRRP and/or RIP. Hydro One Distribution, Alectra Utilities, and Veridian reaffirmed their load forecast developed during the RIP phase and the Study Team deemed this to be adequate for this NA.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Toronto Region includes the area roughly bordered geographically by Lake Ontario on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east. It consists of the City of Toronto, which is the largest City in Canada and the fourth largest in North America. Please see Figure 1 for the map.

The Toronto Region is comprised of the City of Toronto. Electrical supply to the Region is provided by thirty-five 230kV and 115kV transmission and step-down stations as shown in Figure 2. The eastern, northern and western parts of the Region are supplied by eighteen 230/27.6kV step-down transformer stations. The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS) and fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations.

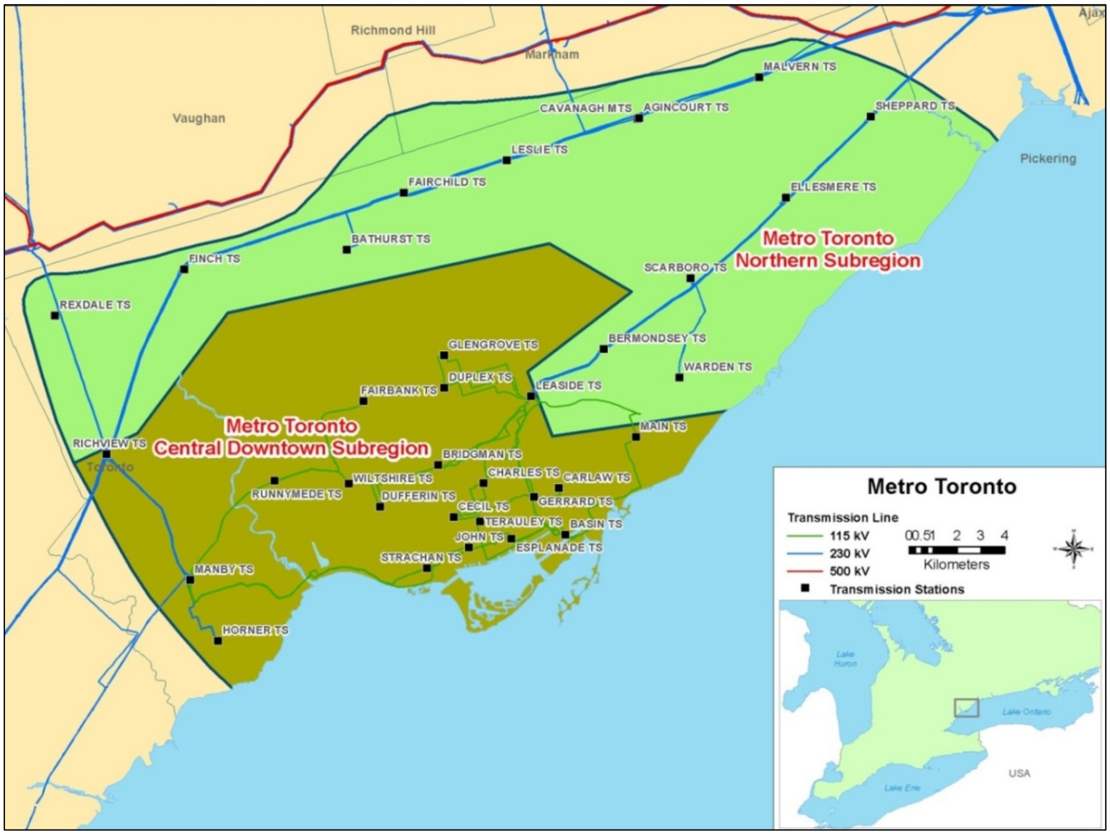


Figure 1: Toronto Regional and Sub-Regional Boundaries

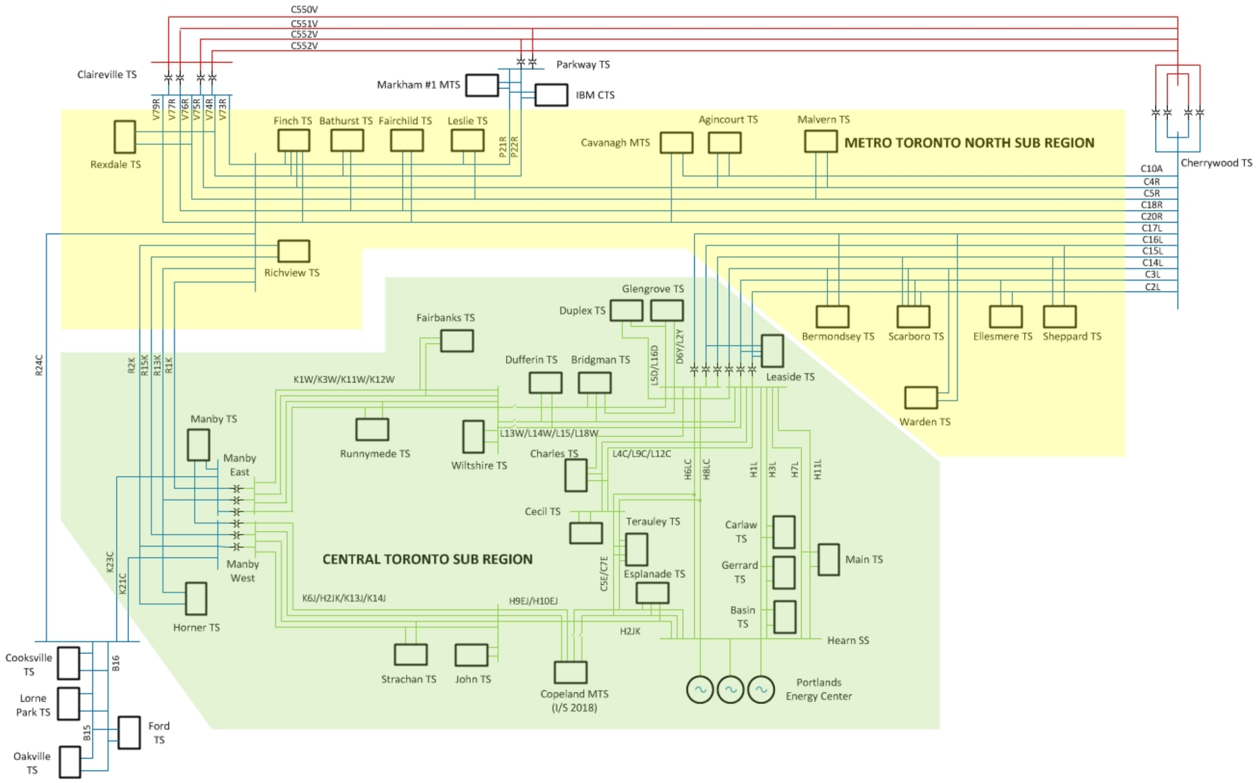


Figure 2: Toronto Region – Single Line Diagram

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the Toronto Region NA. The information provided includes the following:

- Load Forecast updates and/or reaffirmed from previous Toronto RIP;
- Any known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and,
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the Toronto Region

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

i. Load forecast: THESL provided an updated load forecast. Hydro One Distribution, Alectra Utilities, and Veridian reaffirmed their load forecast developed during the RIP phase and the Study Team deemed this to be adequate for this NA (for more details on the RIP load forecast, please refer to Section 5 of the RIP report). The LDC's load forecast is translated into load growth rates and is applied onto the 2016 actual summer station peak load, adjusted for extreme weather conditions (according to Hydro One's methodology). It should be noted that the actual versus forecasted year to year demand can vary due to factors such as weather, economic development, etc.

   In addition, THESL is currently undertaking a study to develop a new load forecast, expected to be completed by Q4 2017. This updated load forecast will be taken into account during the next phases of regional planning, i.e. IRRP and/or RIP.

ii. Relevant information regarding system reliability and operational issues in the region;

iii. List of major HV transmission equipment a) recently replaced b) planned and/or identified to be refurbished due to the end of their useful life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

Technical assessment of needs was based on:

i. Station capacity and Transmission Adequacy assessment

ii. System reliability and operation assessment

iii. End-of-life equipment: Major high voltage equipment reaching the end of its useful life with respect to replacing it with similar type equipment versus other options to determine the most optimal, resilient, and economic outcome.

Note that the Region is summer peaking so the assessment is based on summer peak loads.

7 NEEDS

This section describes emerging needs that have been identified in the Toronto Region since the previous regional planning cycle and reaffirms the near, medium, and long-term needs already identified in the previous RIP. The needs are summarized in Tables 2 and 3 below:

Table 2: New Needs

New Needs	Discussed in Section
End-of-Life Assets	7.1.1
East Harbor / Port Lands Area and Basin TS – Transformation Capacity	7.1.2
Load Restoration – C14L+C17L, C5E+C7E, K3W+K1W	7.1.3

Table 3: Needs Identified in Previous RIP and IRRP (1)

Needs Identified in Previous RIP	Discussed in Section	RIP Report Section
Southwest Toronto – Station Capacity	7.2.1	7.2
Downtown District – Station Capacity	7.2.2	7.3
230 kV Richview x Manby Corridor – Line Capacity	7.2.3	7.4
Supply Security – Breaker Failure at Manby West & East TS	7.2.4	7.6
230/115kV Leaside Autotransformers – Transformation Capacity	7.2.5	7.10
Voltage Instability of 115kV Leaside Subsystem	7.2.5	Identified in Central Toronto Area IRRP report – Appendix E
115 kV Leaside x Wiltshire Corridor – Line Capacity	7.2.6	7.10
230/115kV Manby Autotransformers – Transformation Capacity	7.2.7	7.10
115kV Manby West x Riverside Junction – Line Capacity	7.2.8	7.10
115kV Don Fleet JCT x Esplanade TS – Line Capacity	7.2.9	Identified in Central Toronto Area IRRP report – Appendix E

(1) Includes needs identified in the previous RIP and IRRP that do not have plans underway yet

7.1 New Needs

7.1.1 End-Of-Life (EOL) Asset Needs

Hydro One has identified the following major high voltage equipment and transmission lines to be reaching the end of their useful life over the next 10 years. Based on the equipment condition assessment including relevant tests, these EOL assets have been identified to be in poor condition. Replacement plans for EOL assets are summarized below in Table 4 with exceptions where implementation plans were developed and projects are already underway.

Table 4: End-of-Life Assets – Toronto Region

EOL Asset[1]	Replacement/ Refurbishment Timing[2]	Details
Fairbank TS: T1/T3, T2/T4 Transformers	2022-2023	EOL Transformers and other HV equipment are identified at these stations for replacement with similar type equipment with same ratings, and are discussed further in Section 7.1.1.1.
Fairchild TS: T1/T2 Transformers	2023-2024	
Leslie TS: T1 Transformer	2023-2024	
Runnymede TS: T3/T4 Transformers	2021-2022	
Sheppard TS: T3/T4 Transformers	2019-2020	
Bridgman TS: T11/T12/T13 Transformers	2022-2023	EOL Transformers and other HV equipment are identified at these stations for replacement with higher rated equipment, and are discussed further in Section 7.1.1.2
Charles TS T3/T4 Transformers	2024-2025	
Duplex TS: T1/T2	2023-2024	
Strachan TS: T12 Transformer	2020-2021	
Bermondsey TS: T3/T4 Transformers	2023-2024	EOL Transformers and other HV equipment are identified at these stations where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.3
John TS: T1, T2, T3, T4, T6 Transformers and 115 kV Breakers	2025-2026	
Main TS: T3/T4 Transformers and 115 kV line disconnect switches	2021-2022	
Manby TS: T7, T9, T12 Autotransformers, T13 Step-Down Transformer and rebuild 230kV yard	2024-2025	
115kV C5E/C7E Underground Cable: Esplanade TS to Terauley TS	TBD	EOL Line sections are identified for replacement where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.4
115kV H1L/H3L/H6LC/H8LC: Bloor Street JCT to Leaside JCT	TBD	
115kV L9C/L12C: Leaside TS to Balfour JCT	TBD	

(1) No other lines or stations in the Toronto region have been identified for major replacement/refurbishment at this time
(2) The replacement/refurbishment scope, timing, and prioritization are under review/development and are subject to change

The end-of-life equipment assessment for the above assets considered the following options:

1. Maintaining the status quo
2. Downsizing equipment with lower ratings and built to current standards by transferring load to underutilized facilities within a station or between stations
3. Eliminating equipment by transferring load to underutilized facilities within a station or between stations
4. Replacing equipment with similar equipment with same ratings and built to current standards
5. Replacing equipment with similar equipment with higher ratings and built to current standards

The study team agreed that non-wire options were not a viable option in cases where it has been recommended to replace EOL transformers with a similar transformer with the same or higher ratings (refer to section 7.1.1.1 and 7.1.1.2). With respect to (1), the EOL assets listed in Table 4 are in poor condition so maintaining the status quo for these assets is not an option due to the risk of equipment failure, customer outages and increased maintenance cost.

With respect to (2) and (3), it should be noted that the City of Toronto (within Toronto Region) is one of the most populous and congested cities in Canada where there is continued development, population and economic growth resulting in greater electricity demand. Efficient and effective/maximum use of land and station facilities includes planning ahead for long-term electricity needs, reliability and system resiliency. The majority of stations in the Toronto Region are above and forecasted to be over 75% of their Limited Time Rating ("LTR"). Accordingly, eliminating transformation capacity is not an option because total loads cannot be permanently transferred to neighboring stations. In addition, it is worth noting that:

- Upgrading equipment with higher capacity has very little incremental cost compared to replacing the equipment with similar equipment of the same or lower ratings. For example, it may cost $200-$300 thousand extra for the larger transformers rather than replacing them with similar transformers of the same or lower ratings now and then having to upgrade it later (due to eventual load growth) within the lifetime of the transformer for an additional cost of $5-$10M.
- Maintaining or upgrading capacity to the maximum at the station is the most effective and efficient use of maximizing land and infrastructure for little incremental cost, if any. The higher capacity at very low cost also provides operational flexibility, high resiliency during emergency and extreme weather conditions.
- There is no expectation and/or plan to downsize upstream facilities and therefore downsizing existing station capacity is not prudent.

Therefore, in many cases options (4) and (5) are considered better options. Further rationale for these options is provided in sections 7.1.1.1 to 7.1.1.4.

7.1.1.1 EOL Transformers: Replace with Similar Equipment with Same Ratings

This section describes EOL transformers which are recommended to be replaced with similar type of equipment with same ratings and built to current standards. This was determined to be the preferred option for the reasons listed below:

- Based on historical loading, future electricity needs, and the need for greater resiliency, it is not prudent to reduce the capacity of or eliminate the station, while still maintaining the capacity to reliably supply the demand.
- Hydro One has standardized transformer sizes in order to save costs on procurement, engineering, spares management, maintenance etc. For sustainment purposes the appropriate sized standard transformer is installed, which in some cases may be larger than what the load would currently require, but it is financially prudent.
- The cost savings of replacing EOL transformers with similar units of lower ratings (as opposed to similar units with the same ratings) is not significant compared to the cost of upgrading the

transformers in the future when needed. For example, it may cost $200-$300 thousand extra for the same size transformers as opposed to the smaller ones with lower ratings whereas upgrading them later (due to eventual load growth) within the lifetime of the transformer may cost an additional $5-$10 million. Such changes may also require reconfiguration of LV facilities resulting in additional cost.

- Customer determined that they do not require upgraded transformer(s) because:
    - current load forecast for electricity needs and existing configuration at station does not warrant an upgrade in capacity; or,
    - other measures, where feasible, are being taken to accommodate load growth (e.g. load transfers, new station being built, conservation and demand management programs)
- There is a need for the existing feeders to maintain distribution connections/reliability
- Non-wires options are not a viable option to address the need for these specific EOL transformers

Additional comments and further rationale for the Study Team's recommendations are provided below.

Fairbank TS

Fairbank TS comprises two DESN units, T1/T3 (50/83 MVA) and T2/T4 (50/83 MVA), having a summer 10-Day LTR of 182 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 169 MW and is forecasted to be approximately 173 MW and 188 MW in 2017 and 2027 respectively. Transformers T1/T3 and T2/T4 are currently about 46 years old and have been identified to be at their EOL.

The load at Fairbank TS is forecasted to exceed its LTR in the medium term. As per the IRRP and RIP recommendations, a new Runnymede TS T1/T2 DESN will be built and is expected to be in-service in 2018. Currently, two feeders from Fairbank TS are planned to be moved to the new Runnymede TS T1/T2 DESN to keep Fairbank TS load under its LTR. The other two closest stations, Duplex TS and Glengrove TS, are 13.8kV stations so permanent load transfer from Fairbank TS, which is a 27.6kV station, is not a viable option. Further, the load at Duplex TS is forecasted to be over 90% of its LTR in the medium term. For these reasons, downsizing T1/T3 and T2/T4 to 42MVA transformers (the lower rated standard transformer size for 115/27.6kV) is not prudent. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The timing of replacement for the EOL equipment is 2022-2023.

Fairchild TS

Fairchild TS comprises two DESN units, T1/T2 (75/125 MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 346 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 272 MW and is forecasted to be approximately 275 MW and 296 MW in 2017 and 2027 respectively. Transformers T1 is 43 years old and has been identified to be at its EOL. The companion DESN transformer T2 failed and was replaced under emergency this year with a similar 75/125 MVA unit.

The load at Fairchild TS is forecasted to be over 85% of its LTR in the medium term. The load at the two closest stations, Bathurst TS and Leslie TS, is also forecasted to be over 85% and 90% of their respective LTR's in the medium term. Therefore, downsizing T1 and consolidating load within the station and/or with area stations is not a prudent or viable option given medium term load growth at these stations. It is also important to note that the station is configured as a dual secondary yard (230/27.6-27.6kV) and the standard lower rated unit has only one secondary and would have different impedance than the companion T2 transformer. Consequently, replacing T1 with a lower rated unit could cause significant operational and configuration issues. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers. Upgrading T1 is also not an option since it's already at the maximum standard size.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The timing of replacement for the EOL equipment is 2023-2024.

Leslie TS

Leslie TS comprises two DESN units, T1/T2 (75/125 MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 325 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 237 MW and is forecasted to be approximately 249 MW and 294 MW in 2017 and 2027 respectively. Transformer T1 is currently about 54 years old and has been identified to be at its EOL. The companion DESN transformer T2 is currently 19 years old and is not close to its EOL.

The load at Leslie TS is forecasted to be 90% of its LTR in the medium term. The load at the three closest stations, Fairchild TS, Cavanagh MTS, and Agincourt TS, is also forecasted to be over 85%, 65%, and 65% respectively of their LTR's in the medium term. Although Agincourt TS and Cavanagh MTS have available station capacity, they do not have spare feeder positions to potentially accommodate a permanent load transfer from Leslie TS as more than one feeder would have to be transferred to make downsizing T1 to 83MVA feasible. Adding new feeder positions would be much more costly as opposed to replacing the transformer with a similar unit. Therefore, downsizing T1 and consolidating load within the station and/or with Fairchild TS is not prudent given medium term load growth at these stations and because permanent load transfer to Agincourt TS and Cavanagh MTS is not a viable or economical option. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers. Upgrading T1 is also not an option since it's already at the maximum standard size.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The timing of replacement for the EOL equipment is 2023-2024.

Runnymede TS

Runnymede TS comprises one DESN unit, T3/T4 (58/93 MVA), having a summer 10-Day LTR of 111 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 119 MW and is forecasted to be approximately 121 MW and 185 MW in 2017 and 2027 respectively. Transformers T3/T4 are currently about 45 years old and have been identified to be at their EOL.

As per the previous IRRP and RIP report, building a new Runnymede TS T1/T2 DESN (50/83 MVA) was recommended and is expected to be in service in 2018-2019 to supply the load growth in this area and will keep the Runnymede TS T3/T4 DESN under its LTR. The neighbouring station, Fairbank TS, is also forecasted to exceed its capacity in the near term and currently two of its feeders are planned to be moved to the new Runnymede TS T1/T2 DESN to keep its load under its LTR. Further, the other closest station, Wiltshire TS, is a 13.8kV station so permanent load transfer from Runnymede T3/T4, which is a 27.6kV DESN, is not a viable or economical option. For these reasons, downsizing T3/T4 to 42MVA transformers (the lower rated standard transformer size for 115/27.6kV) is not prudent. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The timing of replacement for the EOL equipment is 2021-2022

Sheppard TS

Sheppard TS comprises two DESN units, T1/T2 (75/125 MVA) and T3/T4 (50/83 MVA), having a summer 10-Day LTR of 204 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 170 MW and is forecasted to be approximately 171 MW and 192 MW in 2017 and 2027 respectively. Transformers T3/T4 are currently 55 years old and have been identified to be at their EOL.

The load at Sheppard TS is forecasted to be over 90% of its LTR in the medium term. However, the Sheppard TS T1/T2 DESN is more lightly loaded than the T3/T4 DESN (T3/T4 is approximately 60% of total station loading in the past three years). Given the potential for load transfers from the T3/T4 DESN to the T1/T2 DESN, upgrading T3/T4 is not prudent. Downsizing T3/T4 is also not an option since the transformers are already at the smallest standard size for a 230/27.6kV DESN.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The timing of replacement for the EOL equipment is 2019-2020.

7.1.1.2 EOL Transformers: Replace with Similar Equipment with Higher Ratings

This section describes EOL transformers which are recommended to be replaced with similar type units with higher ratings (60/100 MVA units) and built to current standards. As stated earlier, maintaining or upgrading capacity to the maximum at the station is the most effective and efficient use of maximizing land and infrastructure. Upgrading equipment with higher capacity has little incremental cost compared to replacing the equipment with similar equipment of the same or lower ratings. For example, it may cost $200-$300 thousand extra for the larger transformers rather than replacing them with similar transformers of the same or lower ratings now and having to upgrade it later (due to eventual load growth) within the lifetime of the transformer for an additional $5-$10M. Upgrading equipment also provides additional flexibility and reliable supply in emergency situations. This was also determined to be the preferred option for the reasons listed below:

- Load transfer is not viable because:
  - Capability to transfer load does not currently exist or is not cost effective at the distribution level
  - Insufficient proximity of neighbouring stations that have capacity to accommodate load transfer
- Hydro One has standardized transformer sizes in order to save costs on procurement, engineering, spares management, maintenance etc. For sustainment purposes the appropriate sized standard transformer is installed, which in some cases may be larger than what the load would currently require, but it is financially prudent.
- Customer does not require an upgrade of transformer(s) to accommodate load growth in area;
- Non-wire options are not a viable option to address the need for these specific EOL transformers

Bridgman TS

Bridgman TS comprises of five transformers, T11, T12, T13, T14, and T15, having a summer 10-Day LTR of 183 MW. The station’s 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 159 MW and is forecasted to be approximately 162 MW and 175 MW in 2017 and 2027 respectively. Transformers T11, T12 and T13 (46/67 MVA) are currently about 50 years old and have been identified to be at their EOL.

The load at Bridgman TS is forecasted to be over 95% of its LTR in the medium term. The load at four of the closest stations, Cecil TS, Charles TS, Duplex TS, and Dufferin TS, is also forecasted to be over 80% of their respective LTR’s in the medium term. Therefore, downsizing T11, T12, and T13 and consolidating load within the station and/or with area stations is not a prudent or viable option given long term load growth at these stations. It should also be noted that by upgrading T11, T12, and T13 to 100MVA units (the higher rated standard transformer size for 115/13.8-13.8kV), similar to the T15 unit, T14 can ultimately be removed while still increasing capacity and at a lower cost compared to replacing all the transformers with similar units with the same ratings. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The EOL transformers will be replaced with 60/100MVA units and the timing of replacement is 2022-2023.

Charles TS

Charles TS comprises two DESN units, T1/T2 (60/100 MVA) and T3/T4 (45/75 MVA), having a summer 10-Day LTR of 200 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 139 MW and is forecasted to be approximately 146 MW and 174 MW in 2017 and 2027 respectively. Transformers T3/T4 are currently about 50 years old and have been identified to be at their EOL.

The load at Charles TS is forecasted to be over 85% of its LTR in the medium term. The load at three of the closest stations, Bridgman TS, Cecil TS and Terauley TS, is also forecasted to be approaching their respective LTR's in the medium term. Therefore, downsizing T3/T4 and consolidating load within the station and/or with area stations is not a prudent or viable option given medium term load growth at these stations. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The EOL transformers will be replaced with 60/100MVA units and the timing of replacement is 2024-2025.

Duplex TS

Duplex TS comprises two DESN units, T1/T2 (45/75 MVA) and T3/T4 (45/75 MVA), having a summer 10-Day LTR of 121 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 97 MW and is forecasted to be approximately 101 MW and 109 MW in 2017 and 2027 respectively. Transformers T1/T2 are currently about 49 years old and have been identified to be at their EOL.

The load at Duplex TS is forecasted to be 90% of its LTR in the medium term. The load at two of the closest stations, Bridgman TS and Glengrove TS, is also forecasted to be over 95% and 65% respectively of their LTR's in the medium term. Although Glengrove TS has capacity in the medium term, maximizing use of existing land and station facilities at Duplex TS (as opposed to downsizing or eliminating) allows for effective planning for long-term electricity needs, reliability and system resiliency. The third neighbouring station, Fairbank TS, is a 27.6kV station so permanent load transfer from Duplex TS, which is a 13.8kV station, is not a viable or economical option. Further, the load at Fairbank TS will be close to its LTR following the transfer of its two feeders to the new Runnymede T1/T2 DESN). For these reasons downsizing T1/ T2 is not prudent. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The EOL transformers will be replaced with 60/100MVA units and the timing of replacement is 2023-2024.

Strachan TS

Strachan TS comprises two DESN units, T12/T14 (T12: 40/67 MVA; T14: 45/75 MVA) and T13/T15 (45/75 MVA), having a summer 10-Day LTR of 161 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 142 MW and is forecasted to be approximately 148 MW and 166 MW in 2017 and 2027 respectively. Transformer T12 is currently about 60 years old and has been identified to be at its EOL. The companion DESN transformer T14 is currently 42 years old and is not at its EOL.

The load at Strachan TS is forecasted to approach capacity in the medium term. The load at the closest station, John TS, is also forecasted to be 85% of its LTR's in the medium term. Therefore, downsizing T12 and consolidating load within the station and/or with area stations is not a viable option given medium term load growth at these stations. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformers plus the incremental cost for the LDC to reconfigure feeders. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

Apart from the above transformer replacement options, the Study Team suggested evaluating the option of replacing T12 with a 115/230kV dual winding transformer (versus 115kV) since the 115kV cables, K6J and H2JK, between Strachan TS and Riverside JCT were recently replaced with cables built to 230kV (but currently operating at 115kV). It was determined that this option is not viable as there is insufficient space at the Strachan TS site to accommodate this and the associated station reconfiguration that would be required. Moreover, these dual winding transformers are not standard and would have to be custom built (if possible) which would result in a significant incremental cost, including the additional operating and maintenance costs, compared to replacing the transformer with a similar standard unit.

Based on the above, the study team recommends that this need be addressed by Hydro One and THESL to coordinate the replacement plan. The EOL transformer will be replaced with a 60/100MVA unit and the timing of replacement is 2020-2021. The preliminary plan also includes the upgrade of 115kV strain bus and replacement of 115kVdisconnect switches.

7.1.1.3 EOL Station Equipment: Replacement Plan to be Further Assessed

This section describes EOL station equipment where the replacement plan requires further assessment and regional coordination.

Bermondsey TS

Bermondsey TS comprises two DESN units, T1/T2 (75/125MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 348 MW. The station’s 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 179 MW and is forecasted to be approximately 185 MW and 200 MW in 2017 and 2027 respectively. Transformers T3 and T4 are currently about 51 years old and have been identified to be at their EOL.

The load at Bermondsey TS is forecasted to be 57% of its LTR in the medium term. The Bermondsey T1/T2 DESN is more lightly loaded than the T3/T4 DESN (T3/T4 is approximately 70% of total station loading over the last 3 years).The load at the three closest stations, Scarboro TS, Warden TS, and Leaside TS is forecasted to be over 75%, 85%, and over 95% respectively of their LTR’s in the medium term.

A review of options such as the feasibility of downsizing T3/T4 and partially consolidating with T1/T2 DESN and/or with area stations should be assessed. Hence, further regional coordination in the IRRP and/or RIP phase is required to identify a preferred replacement plan. The timing of replacement for EOL equipment is 2023-2024.

John TS

John TS is connected to the 115kV Manby West system and jointly supplies Toronto’s downtown district. Station facilities include six 115/13.8kV step-down transformers (T1, T2, T3, T4, T5, T6) and a 115kV switchyard. The summer 10-Day LTR is 262 MW. The station’s 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 282 MW and is forecasted to be approximately 285 MW in 2017 and 224 MW in 2027 due to load transfers to the new Copeland MTS scheduled to be in service in 2018 (Phase 1).

John TS was built in the 1950’s and THESL’s switchgear at the station has reached the end of its useful life. It is expected to be replaced with new metalclad line-ups in the near term around 2022-2023. In addition, five step-down transformers at John TS, T1, T2, T3, T4, and T6, as well as the 115 kV breakers have been identified to be at the end of their useful life and require replacement within the near to medium term. The new equipment is currently expected to be in service by 2025-2026.

Since John TS requires a significant rebuild including the replacement of all EOL assets, options and an implementation plan need to be further assessed as part of the IRRP and RIP phase to develop a comprehensive plan. In addition, coordination of this work with Copeland MTS will be important because Copeland MTS' added capacity will be needed in order to improve execution of the replacement plan at John TS to maintain reliable supply in Toronto's downtown district. Therefore, it is recommended that the replacement plan for EOL equipment at John TS be further assessed as part of the IRRP and RIP phase.

Main TS

Main TS comprises one DESN unit, T3/T4 (45/75 MVA), having a summer 10-Day LTR of 74 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 64 MW and is forecasted to be approximately 65 MW and 70 MW in 2017 and 2027 respectively. Transformers T3/T4 are currently about 49 years old and have been identified to be at their EOL.

The load at Main TS is forecasted to be 95% of its LTR in the medium term. The load at two of the closest stations, Carlaw TS and Warden TS, is forecasted to be at capacity, and 85% of LTR respectively in the medium term. Main TS is a 115/13.8 kV station that is supplied by the Leaside 115 kV system. There is a need to relieve Leaside autotransformers (described in section 7.2.5) in the long term (beyond 2027[1]). Moving over 60 MW of load (2016 actual non-coincident summer peak load) from Main TS off of the Leaside 115kV supply and onto the upstream 230 kV supply (CxL circuits) could potentially defer the need for Leaside autotransformer upgrades (or a new transmission supply point) by 4-5 years. This deferral could represent a significant value to ratepayers.

Accordingly, the Study Team will further assess the option of adding a 230/13.8 kV DESN at Warden TS with express 13.8 kV feeders running to Main TS along with other potential options. Hence, further regional coordination in the IRRP and/or RIP phase is required to identify a preferred replacement plan. The timing of replacement for EOL equipment is 2021-2022.

Manby TS

Manby TS is a major switching and autotransformer station in the Toronto region. Station facilities include six 230/115kV autotransformers (T1, T2, T7, T8, T9, T12), a 230 kV switchyard, a 115kV switchyard, and six 230/27.6kV step-down transformers (T3, T4, T5, T6, T13, T14). The total summer 10-Day LTR of the six step-down transformers is 226 MW. The station's 2016 actual non-coincident summer peak load (adjusted for extreme weather) was about 206 MW and is forecasted to be approximately 208 MW and 252 MW in 2017 and 2027 respectively. Three of the autotransformers, T7, T9, and T12, and one of the step-down transformers, T13, are close to 50 years old and have been identified to be at the end of their useful life. The 230 kV oil breakers have also been identified to be at EOL and require replacement. The timing of replacement for EOL equipment is 2024-2025.

[1] The need date assumes that two of the three units at Portland Energy Centre are out and total plant generation is 160MW and a high demand growth scenario. Under a low demand growth scenario, the need was identified in the IRRP to occur in the post 2035 timeframe, which was outside of the IRRP study timeframe. The need for Leaside autotransformer relief will be re-assessed as part of the next IRRP.

In addition to the EOL asset needs at Manby TS, there are also needs for: additional step down transformation capacity to relieve Manby TS loading discussed in section 7.2.1; transmission line capacity on the 230kV Richview TS to Manby TS corridor discussed in section 7.2.3; addressing potential violation of ORTAC load rejection limit of 150 MW discussed in section 7.2.4; and, transformation capacity to relieve Manby TS 230/115kV autotransformers in the long term discussed in section 7.2.7. Since the EOL equipment need may impact these additional needs it is recommended that the replacement plan for EOL equipment at Manby TS be further assessed as part of the IRRP and RIP phase.

7.1.1.4 EOL Transmission Lines

The table below lists sections of HV overhead lines and underground cables in the Toronto Region that are at the end of their useful life and require replacement in the near term.

Table 5: End-of-Life Lines

EOL Lines	Voltage Level (kV)	Est. Conductor Replacement (route length, km)	Asset Age (years)	Description
C5E/C7E (UG Cable)	115	3.6	58	Replacement of deteriorated cable from Esplanade TS to Terauley TS
H1L/H3L/H6LC/H8LC	115	2.05	64	Replacement of deteriorated overhead line from Bloor St. JCT to Leaside JCT
L9C/L12C	115	3.55	88	Replacement of deteriorated overhead line from Leaside TS to Balfour JCT

C5E/C7E Cable

Circuits C5E and C7E provide critical 115kV supply to Toronto’s downtown core. The underground cables from Esplanade TS to Terauley TS (about 3.6 route km) are paper-insulated low pressure oil filled and are 58 years old and partially routed along Lake Ontario. These cables are in poor condition and deemed to be at the end of their useful life, and hence require replacement in the near-term. Due to their deteriorated condition, the risk of cable failure and oil leaks resulting in loss of supply and adverse environmental impact will only increase with age.

The preliminary scope of work involves replacement of the 115kV low pressure oil filled underground transmission cable with XLPE cable between Esplanade TS to Terauley TS with a 1200A continuous summer rating and an option for insulation for 230kV, although the cable would be operated at 115kV. The need and cost for a higher rated cable will also be assessed. Various routes will be identified and evaluated such as the existing route, utilizing the John x Esplanade TS tunnel, etc. The route investigation will assess existing easements and right-of-ways, cost, and other technical and environmental considerations. OEB Leave to Construct approval may be required.

Further regional coordination in the IRRP and RIP phase is required to review options and identify a preferred replacement plan.

H1L/H3L/H6LC/H8LC

Circuits H1L, H3L, H6LC, and H8LC provide 115kV supply to the eastern part of central Toronto from Hearn TS to Leaside TS. The line section between Bloor St. JCT to Leaside JCT (about 2 route km), is 64 years old and its conductors have been identified as reaching the end of their useful life and require replacement for safety, reliability and maintainability purposes.

The preliminary scope of work involves refurbishing the circuits between Bloor St. JCT to Leaside JCT to like-new conditions and built to current standards. Options for upgrading the circuits to 230kV will also be assessed.

Further regional coordination in the IRRP and RIP phase is required to review options and identify a preferred replacement plan.

L9C/L12C

Circuits L9C and L12C provide 115kV supply to central Toronto from Leaside TS to Cecil TS. The line section between Leaside TS and Balfour JCT (about 3.6 route km), are over 80 years old and their conductors have been identified as reaching the end of their useful life and require replacement for safety, reliability and maintainability purposes.

The preliminary scope of work involves refurbishing the circuits between Leaside TS and Balfour JCT to like-new conditions and built to current standards.

Further regional coordination in the IRRP and RIP phase is required to review options and identify a preferred replacement plan.

7.1.2 East Harbor / Port Lands Area – Transformation Capacity

THESL has identified an emerging area of load growth in the East Harbor and Port Lands in Toronto. The current load in the area is supplied from Esplanade TS and Basin TS. The area currently consists of prime land for future development. Among recent proposals in the East Harbor includes re-development of a former 60-acre Unilever factory site as a new master-planned district consisting of commercial and residential towers. Nearby, the Port Lands have also been in the City of Toronto's plans for renewed development. In addition to these, the potential expansion of Ashbridges Bay Wastewater treatment plant and the future construction of the Toronto Transit Commission's (TTC) downtown relief subway line may also impact load growth in the area. Recently THESL has been in discussions with Toronto Water for the tentative connection of about 14MVA of new electrical load.

Transformation capacity in the area is sufficient with present day loading however, due to the area's load growth potential there may be a need for increased capacity around 2025+. The infrastructure planning for this expansion could be complex due to urban vicinity and municipal plans/needs and should be undertaken for broader coordination as soon as possible. The existing Basin TS and Esplanade TS load forecasts do not include the impact of this major undertaking. Furthermore, based on the existing Basin TS forecast, it may reach capacity by 2026 and slightly exceed its LTR by 2027.

Further regional coordination in the IRRP and RIP phase is required to review options and identify a preferred plan.

7.1.3 Load Restoration – C14L+C17L, C5E+C7E, and K3W+K1W

For the loss of 230kV circuits C14L and C17L (stations connected are Warden TS and Bermondsey TS), the load interrupted by configuration can exceed 150 MW and 250 MW and are required to be restored within the prescribed time periods as stated in the ORTAC.

For the loss of 115kV circuits C5E and C7E (station connected is Terauley TS), the load interrupted by configuration can exceed 150 MW over the study period and are required to be restored within the prescribed time periods as stated in the ORTAC.

For the loss of 115kV circuits K3W and K1W (stations connected are Fairbank TS and Wilshire TS), the load interrupted by configuration can exceed 150 MW and 250 MW and are required to be restored within the prescribed time periods as stated in the ORTAC.

Further regional coordination in the IRRP and RIP phase is required to review options and identify a preferred restoration plan.

7.2 Needs Identified in Previous RIP

The following section summarizes the needs and their respective plans identified in the previous RIP report which are not yet underway. The Study Team reaffirms these needs and an update with respect to their plans is provided below.

7.2.1 Southwest Toronto – Station Capacity

To address the station capacity need at Manby TS and Horner TS, the RIP recommended adding two 230/27.6 kV, 75/125MVA transformers and a new 27.6kV switchyard at the existing Horner TS site. New distribution feeder ties are required to be built between Manby TS and Horner TS by THESL to accommodate load transfer out of Manby TS to Horner TS as the loading at Manby TS exceeds its capacity. The need date is 2021. For more details, refer to section 7.2 of the RIP report.

The Study Team reaffirms this need. Hydro One is continuing the development and estimate work for this project. The planned in service date is 2020.

7.2.2 Downtown District – Station Capacity

The Toronto Downtown District is mainly supplied by the three existing 115/13.8 kV stations: John TS, Esplanade TS, and Terauley TS. THESL is building a new 115/13.8kV owned transformer station, Copeland MTS, in the Downtown District near John TS with normal supply from the 115 kV Manby West system. Copeland MTS Phase 1 is currently under construction with a planned in service date of 2018. It will provide a new source of supply to the area customers.

As identified in the RIP report (refer to section 7.3 of the RIP report), a number of factors including additional transformation capacity, but also feeder positions would drive the need for Copeland MTS Phase 2 – a second 115/13.8kV DESN[2] at the Copeland MTS site. THESL anticipates that the need for a new transformation facility is more advanced due to: significant load transfers required to facilitate the refurbishment work at John TS (as discussed in section 7.1.1.3); and, limited spare feeder positions at existing stations for new customer connections and to maintain n-1 contingencies for dual radial feeders. THESL foresees substantial load additions due to new developments to the east of the station, which are not included in the existing Copeland MTS forecast.

Based on the station capacity consideration alone for the Downtown District stations, the need date for Copeland MTS Phase 2 is 2027+. However, based on the other considerations identified by THESL such as their requirements for spare feeder positions, the need date may be earlier around 2023-2024.

The Study Team reaffirms this need and recommends that the need and timing for Phase 2 be further refined by THESL through their distribution planning process and included in updates to the next IRRP and/or RIP.

7.2.3 230kV Richview TS x Manby TS Corridor – Line Capacity

Various alternatives were assessed to address the line capacity need for the two double circuit 230kV lines, R1K/R2K and R13K/R15K, along the Richview TS to Manby TS corridor. The RIP recommended that Hydro One proceed with the development and estimate work on the alternatives. With the effect of the proposed Metrolinx Mimico Traction Power Station ("TPS") load, the need date for relief may be 2020 at the earliest. For more details, refer to section 7.4 of the RIP report.

The Study Team reaffirms this need and has determined a recommended plan. This plan is staged as follows:

- Stage 1: Rebuild existing 115kV idle line to 230kV and reconfigure two existing circuits R2K and R15K into "Super-circuits"
- Stage 2: Terminate the new conductors on V73R and V79R circuits and Manby TS (3 new breakers) and complete station work coincident with Manby TS EOL replacement work planned in 2023-2024 (discussed in section 7.1.1.3)

Hydro One is continuing the development and estimate work on this plan with an in service date of 2021. Updates will be included in the next IRRP and RIP.

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[2] A third 60/100 MVA transformer will also be installed, which under normal operation will remain on potential, but off-load. This transformer will only be loaded in the event of a contingency at Copeland MTS or at Windsor TS/John TS (following the replacement of the THESL switchgear after which inter-station support capability will have been installed). The site and the HV switching facilities required to accommodate Phase 2 are already included as part of the Copeland MTS Phase 1 project.

7.2.4 Breaker Failure at Manby TS

To address the risk of breaker failure at Manby TS causing the outage of any two of the three 230/115kV autotransformers at either the west or east yard of Manby TS and resulting in the remaining transformer exceeding its Short Term Emergency (STE) rating, the RIP recommended the installation of a Special Protection Scheme (SPS). The need date is summer 2018 and summer 2021 for Manby West and Manby East respectively. For more details refer to section 7.6 of the RIP report.

The Study Team reaffirms this need. Hydro One is continuing the development and estimate work for this project. The planned in service date is Q2 2018.

Since the RIP, IESO completed a System Impact Assessment (SIA) for the Manby SPS and it found that based on the coincident load forecast in order to respect post contingency thermal ratings of Manby T12 and T7 for the loss of two companion autotransformers, the ORTAC load rejection limit of 150 MW may be exceeded in the long term (around 2028+). This need and associated plan should be coordinated with the 230/115kV Manby TS transformer capacity need discussed in section 7.2.7 and the Manby TS EOL equipment need discussed in section 7.1.1.3. Hence further regional coordination in the IRRP and RIP is required.

7.2.5 230/115 kV Leaside Autotransformers Transformation Capacity and Voltage Collapse

Based on the load forecast, the Leaside TS autotransformers will require relief in the long term, beyond 2027. The need date assumes that two of the three units at Portland Energy Centre (PEC) are out and total plant generation is 160MW.

Following the loss of 230 kV circuits, C16L and C17L, while all three units at PEC are out of service pre-contingency, voltage collapse in the Leaside TS 115kV subsystem may be caused. This becomes a credible contingency once the current PEC contract expires. This need was identified in the Central Toronto Area IRRP report.

The Study Team reaffirms these needs and recommends that they be further assessed in the IRRP and/or RIP phase. For more details, refer to section 6.2.1 of RIP report and Appendix E of the IRRP report.

7.2.6 115 kV Leaside TS x Wiltshire TS Corridor – Line Capacity

Based on the RIP coincident load forecast, the Leaside TS x Wiltshire TS circuits will require relief in the long term (2034). For more details, refer to section 7.10 of the RIP report.

The Study Team reaffirms this need and recommends that it be further assessed in the next phases of the regional planning process, i.e. IRRP and/or RIP.

7.2.7 230/115 kV Manby Autotransformers – Transformation Capacity

Based on the RIP coincident load forecast, the Manby TS autotransformers will exceed their LTE and require relief in the long term (2035+).

As noted in section 7.1.1.3, three of the autotransformers at Manby TS, T7, T9, and T12, are at EOL and require replacement in 2023-2024. Currently, T7 and T9 in the Manby East switchyard are rated about 65 MVA and 40 MVA less than their third companion autotransformer, while T12 in the Manby West switchyard is rated about 52 MVA and 92 MVA less than its two companion autotransformers.

The Study Team reaffirms this need. Since the 230/115kV Manby transformer capacity need impacts the Manby TS EOL plans and the need to address the potential violation of the ORTAC 150 MW load rejection limit (discussed in section 7.2.4), there are benefits to coordinating the plans to address all these needs. Therefore, further regional planning in the IRRP and RIP is required. For more details, refer to section 7.10 of the RIP report.

7.2.8 115 kV Manby West x Riverside Junction – Line Capacity

Based on the RIP coincident load forecast, the Manby West x Riverside Junction circuits will require relief in the long term (2035+). For more details, refer to section 7.10 of the RIP report.

The Study Team reaffirms this need and recommends that it be further assessed in the next phases of the regional planning process, i.e. IRRP and/or RIP.

7.2.9 115 kV Don Fleet Junction x Esplanade TS – Line Capacity

The 115kV circuit H2JK between Don Fleet Junction and Esplanade TS is forecast to exceed its Long Term Emergency (LTE) rating in 2026 following the loss of 115 kV circuit H9EJ. This need was identified in the Central Toronto Area IRRP report.

The Study Team reaffirms this need and recommends that it be further assessed in the next phases of the regional planning process, i.e. IRRP and/or RIP. For more details, refer to Appendix E of the IRRP report.

It should also be noted that Metrolinx is planning to expand their Don Yard in downtown Toronto. The expansion will require the relocation of 115 kV overhead line section, H9EJ and H10EJ between Cherry St. and Don Fleet Junction (approximately 0.6 km) and 115 kV underground cable section, H2JK between Don Fleet Junction and Esplanade TS (approximately 1.8 km).

Further regional coordination in the IRRP and/or RIP phase is required to review options (including upgrading H2JK and converting it to an overhead line) and identify the preferred relocation plan.

8 RECOMMENDATIONS

The Study Team's recommendations to address the needs identified are as follows:

a) The equipment discussed in sections 7.1.1.1 and 7.1.1.2 is 40-60 years old. It has been determined that these assets are at the end of their useful life. From a cost, loading, timing, and customer connection needs perspective, none of these assets should be eliminated or have their capacity reduced. The study team recommends that these EOL needs be addressed by Hydro One and THESL to coordinate the replacement plan.

b) The Study Team will further assess the following needs discussed in sections: 7.1.1.3 (EOL station equipment needs); 7.1.1.4 (EOL line equipment needs); 7.1.2 (transformation capacity needs); 7.1.3. (load restoration need); 7.2.5 to 7.2.9 (needs identified in previous RIP/IRRP, mostly long-term); as part of the next phases of regional planning, i.e. IRRP and RIP, to develop a preferred plan.

c) The Study Team reaffirms the remaining needs that were identified in the previous RIP, discussed in sections 7.2.1 to 7.2.4 of this report. Updates (where relevant) to the associated plans are provided and implementation of these plans should be continued.

The table below summarizes the above recommendations.

Table 6: Summary of Recommendations

Further Regional Coordination Not Required	Further Regional Coordination Required
EOL Station Equipment: • Bridgman TS: T11/T12/T13 • Charles TS: T3/T4 • Duplex TS: T1/T2 • Fairbank TS: T1/T3, T2/T4 • Fairchild TS: T1/T2 • Leslie TS: T1 • Runnymede TS: T3/T4, 115 kV line grounding switches • Sheppard TS: T3/T4 • Strachan TS: T12	**EOL Station Equipment:** • Bermondsey TS: T3/T4 • John TS: T1, T2, T3, T4, T6, 115 kV breakers • Main TS: T3/T4, 115 kV line disconnect switches, installation of 115 kV CVTs • Manby TS: T7, T9, T12 autotransformers, T13 step-down transformer, rebuild 230kV yard **EOL Lines:** • 115kV C5E/C7E Underground Cable: Esplanade TS to Terauley TS • 115 kV H1L/H3L/H6LC/H8LC Overhead Line: Bloor St. JCT to Leaside JCT • 115kV L9C/L12C Overhead Line: Leaside TS to Balfour JCT **Transformation Capacity Need:** • East Harbor / Port Lands Area and Basin TS **Load Restoration Need:** • C14L+C17L (Warden TS and Bermondsey TS)

Further Regional Coordination Not Required	Further Regional Coordination Required
	• C5E+C7E (Terauley TS) • K3W+K1W (Fairbank TS and Wiltshire TS) **Needs identified in Previous RIP/IRRP:** Medium Term • 115kV Don Fleet JCT x Esplanade TS – Line Capacity Long-Term • 230/115kV Leaside TS autotransformers – Transformation Capacity and Voltage Collapse of 115kV Leaside Subsystem • 115kV Leaside TS to Wiltshire TS Corridor – Line Capacity • 230/115kV Manby autotransformers – Transformation Capacity • 115kV Manby West x Riverside Junction – Line Capacity

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Appendix A: Non-Coincident Summer Peak Load Forecast (2016 to 2027)

			LTR (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Central 115kV	Lea115kV	BASIN TS	85	52	61	69	76	81	82	83	83	83	84	85	86
		BRIDGMAN TS	183	159	162	164	164	165	166	169	170	171	172	173	175
		CARLAW TS	70	56	56	65	66	68	68	68	69	69	70	70	70
		CECIL TS	204	173	177	182	190	194	197	198	200	200	202	203	204
		CHARLES TS	200	139	146	155	161	164	166	166	167	169	170	172	174
		DUFFERIN TS	161	132	132	138	124	126	127	127	128	129	131	132	132
		DUPLEX TS	121	97	101	109	113	112	110	108	105	106	107	108	109
		ESPLANADE TS	177	167	169	179	157	160	162	163	163	166	166	168	170
		GERRARD TS	94	38	40	36	46	48	50	50	51	51	51	52	53
		GLENGROVE TS	84	54	54	51	52	54	54	54	56	56	56	56	56
		MAIN TS	74	64	65	66	66	66	67	68	68	68	70	70	70
		TERAULEY TS	205	174	181	188	200	206	199	203	204	204	205	205	205
	ManbyE-115-27.6	FAIRBANK TS	182	169	173	180	162	169	174	178	183	183	185	186	188
		RUNNYMEDE TS	111	119	121	123	169	176	178	178	181	182	183	184	185
	ManbyE-115-13.8	WILTSHIRE TS	126	61	65	63	79	79	80	81	81	83	83	83	83
	ManbyW-115	COPELAND MTS	111	0	0	0	0	54	101	102	103	103	107	107	107
		STRACHAN TS	161	137	143	147	150	154	154	156	156	158	160	160	160
		WINDSOR TS (John TS)	262	282	285	283	286	235	214	217	218	219	222	223	224
Central 115kV Total			2611	2073	2130	2198	2259	2309	2351	2371	2387	2400	2424	2436	2450
Eastern 230kV	CxL230	BERMONDSEY TS	348	179	184	179	184	187	188	192	193	194	196	198	200
		ELLESMERE TS	189	139	141	143	145	147	148	149	150	151	152	153	154
		LEASIDE TS	210	157	164	180	185	190	192	193	194	196	197	199	201
		SCARBORO TS	341	230	235	239	243	245	246	248	249	251	253	254	255
		Metrolinx - Scarboro	0	0	0	0	0	0	0	78	78	78	78	78	78
		SHEPPARD TS	204	170	171	175	178	181	183	185	185	187	188	190	192
		WARDEN TS	183	138	139	144	147	148	149	150	151	152	153	155	156
Eastern 230kV Total			1474	1013	1034	1061	1082	1098	1105	1194	1200	1209	1218	1227	1236
Northern 230kV	CxR	AGINCOURT TS	174	101	101	102	105	108	111	112	113	114	114	114	114
		BATHURST TS	334	232	237	253	264	271	275	276	278	280	282	284	286
		CAVANAGH MTS	157	93	95	95	96	97	97	98	99	100	100	101	102
		FAIRCHILD TS	346	272	275	278	282	284	286	288	290	292	294	295	296
		FINCH TS	363	278	285	293	298	302	304	306	308	310	312	314	316
		LESLIE TS	325	237	249	262	273	277	280	283	286	287	290	292	293
		MALVERN TS	176	95	100	102	105	106	106	107	108	108	109	110	111
Northern 230kV Total			1701	1308	1342	1385	1421	1444	1458	1469	1481	1491	1502	1511	1519
Western 230kV	Manby230	HORNER TS	183	146	155	160	163	165	167	168	169	171	172	173	174
		MANBY TS	226	206	208	218	229	232	241	242	243	245	246	249	252
	Metrolinx	Metrolinx - Cityview	0	0	0	0	0	59	59	59	59	59	59	59	59
		Metrolinx - Mimico	0	0	0	0	0	28	28	28	28	28	28	28	28
	Rich230	REXDALE TS	187	140	142	145	147	148	150	150	152	152	154	154	154
		RICHVIEW TS	454	248	250	256	243	246	248	250	250	252	255	256	257
Western 230kV Total			1049	740	755	779	782	877	892	896	901	908	914	919	924
Grand Total			**6834**	**5134**	**5262**	**5422**	**5545**	**5729**	**5806**	**5930**	**5970**	**6008**	**6057**	**6093**	**6129**

Appendix B: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portland Energy Centre
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TPS	Traction Power Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

GTA North Region

Date: March 20, 2018

Prepared by: GTA North Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the GTA North Region and to recommend which needs may require further assessment and/or regional coordination to develop a preferred plan. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

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Executive Summary

REGION	GTA North		
LEAD	Hydro One Networks Inc. (“HONI”)		
START DATE	December 1, 2017	**END DATE**	March 20, 2018

1. INTRODUCTION

The first cycle of the Regional Planning process for the GTA North Region was initiated in Q2 2014 and completed with the publication of the Regional Infrastructure Plan (“RIP”) in February 2016. The RIP provided a description of needs and recommendations of preferred wires plans to address near-term needs. The RIP also identified some mid- and long-term needs that will be reviewed during this planning cycle.

The purpose of this Needs Assessment is to identify any new needs and reaffirm needs identified in the previous GTA North Region RIP.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. Due to the timing of the mid-term needs identified in the previous Integrated Regional Resource Plan (“IRRP”) and RIP reports as well as new needs in the GTA North Region, the NA was triggered in advance of the regular 5-year review schedule.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the GTA North Region and includes:

- New needs identified by Study Team members; and,
- Review and reaffirm needs/plans identified in the previous RIP

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment (“SA”), IRRP and RIP, based on updated information available at that time.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies (“LDC”), the Independent Electricity System Operator (“IESO”), and Hydro One provided input and relevant information for the GTA North Region regarding capacity needs, system reliability, operational issues, and major assets/facilities approaching end-of-life (“EOL”).

5. ASSESSMENT METHODOLOGY

The assessment’s primary objective is to identify the electrical infrastructure needs in the Region over the study period. The assessment reviewed available information including load forecasts, conservation and demand management (CDM) and distributed generation (DG) forecasts, system reliability and operation issues, and major high voltage equipment identified to be at or near the end of their useful life and requiring replacement/refurbishment.

A technical assessment of needs was undertaken based on:

- Station capacity and transmission adequacy;
- System reliability and operation; and,
- Major high voltage equipment reaching the end of its useful life with respect to replacing it with similar type equipment versus other options to determine the most technically feasible, resilient, and cost effective outcome.

6. RESULTS

I. Aging Infrastructure

In the GTA North Region, high voltage equipment at Woodbridge TS (T5 transformer) was identified to be approaching the end of its useful life and requires replacement in the near-term. Refer to section 7.1.1 for more details.

II. 230kV Connection Capacity

- A transformation capacity need for the Vaughan area was reaffirmed. Based on current extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is beyond 2027. If CDM savings are not achieved as forecasted, the need date may be as early as 2027. Refer to section 7.2.3 for more details.

- A transformation capacity need for the Northern York Area was reaffirmed. Based on current extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is beyond 2027. If CDM savings are not achieved as forecasted, the need date may be as early as 2024. Refer to section 7.2.6 for more details.

III. 230kV Transmission Supply Capacity

Transmission Supply Capacity needs were reaffirmed to connect new transformation capacity in Vaughan and Northern York Areas in the long term. Refer to sections 7.2.3 and 7.2.6 for more details.

IV. System Reliability & Operation

- A load restoration need for the loss of circuits V43+V44 (supplies Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS), was identified during the previous NA for the GTA North Western Sub-Region and the Northwest GTA IRRP. The study team reaffirmed this need. Refer to section 7.2.1 for more details.
- A load restoration need for the loss of circuits, P45+P46 (supplies Buttonville TS, Markham #4 MTS, and future Markham #5 MTS), has been identified in the near term. Refer to section 7.1.2 for more details.
- A load security need was previously identified on the Parkway to Claireville corridor and was reassessed during this NA. The load on this corridor is slightly lower than it was when the previous assessment was completed, although it continues to exceed the 600MW limit. Refer to section 7.2.2 for more details.

V. Station Service Supply to York Energy Centre

A need for addressing station service supply to York Energy Centre was reaffirmed for the near to medium term. Refer to section 7.2.5 for more details.

7. RECOMMENDATIONS

The Study Team's recommendations are as follows:

a) Further regional coordination is not required to address the following needs:
   - EOL Woodbridge TS T5 transformer (discussed in section 7.1.1). The study team recommends that this EOL need be addressed by Hydro One and affected LDCs to coordinate the replacement plan. Hydro One will keep the study team informed of the status of the plan if any major changes occur.

b) As per the IESO's letter of support in April 2017, Hydro One will proceed with development and estimate work to connect a new 230/27.6kV DESN in the Markham-Richmond Hill area in coordination with Alectra (discussed in section 7.2.4). Further updates will be included in the next IRRP and RIP.

c) Further assessment and regional coordination is required in the IRRP and/or RIP, to develop a preferred plan for the following needs:
   - Load Restoration – P45+P46 (discussed in Section 7.1.2)
   - Load Restoration – V43+V44 (discussed in Section 7.2.1)
   - Load Security on V71P/V75P – Parkway to Claireville (discussed in Section 7.2.2)
   - Vaughan Transformation Capacity (discussed in Section 7.2.3)
   - Station Service Supply to York Energy Centre (discussed in Section 7.2.5)
   - Northern York Area Transformation Capacity (discussed in Section 7.2.6)
   - Transmission Supply Capacity in Vaughan and Northern York Area in long term (discussed in sections 7.2.3 and 7.2.6)

TABLE OF CONTENTS

List of Tables and Figures

1 INTRODUCTION

The first cycle of the Regional Planning process for the GTA North Region was completed in February 2016 with the publication of the Regional Infrastructure Plan (“RIP”). The RIP provided a description of needs and recommendations of preferred wires plans to address near and medium term needs. Additional medium and long term needs were recommended for further review during the next regional planning cycle.

The purpose of this Needs Assessment (“NA”) is to identify new needs and reconfirm the needs identified in the previous GTA North regional planning cycle. Since the first regional planning cycle, some new needs in the region have been identified.

This report was prepared by the GTA North Region Study Team (“Study Team”), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. The report captures the results of the assessment based on information provided by the lead transmitter, Local Distribution Companies (“LDC”) and the Independent Electricity System Operator (“IESO”).

Table 1: GTA North Region Study Team Participants

Company
Alectra Utilities Corporation (formerly Enersource Hydro Mississauga, PowerStream Inc., Hydro One Brampton)
Hydro One Networks Inc. (Distribution)
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator (“IESO”)
Newmarket-Tay Power Distribution Ltd. (“Newmarket-Tay”)
Toronto Hydro-Electric System Limited (“THESL”)
Veridian Connections Inc. (“Veridian”)

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. Due to the timing of the mid-term needs identified in the previous IRRP and RIP reports as well as new needs in the GTA North Region, the study team recommended to trigger the next cycle in advance of the regular 5-year review schedule.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the GTA North Region and includes:

- Identification of new needs based on latest information provided by the Study Team; and,
- Confirmation/updates of existing needs and/or plans identified in the previous planning cycle.

The Study Team may identify additional needs during the next phases of the planning process, namely Scoping Assessment (“SA”), Local Planning (“LP”), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The GTA North Region is approximately bounded by the Regional Municipality of York, and also includes parts of the City of Toronto, Brampton, and Mississauga. The region is divided into two sub-regions:

- York Sub-Region: This area includes Southern York area (the Municipalities of Vaughan, Markham, and Richmond Hill) and Northern York area (the Municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville, Georgina, and some parts of Durham and Simcoe regions are supplied from the same electricity infrastructure).
- Western Sub-Region: This area comprises the western portion of the City of Vaughan.

Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B82V/B83V in King Township.

Please see Figure 1 and Figure 2 for a map and single line diagram of the Sub-Region facilities.

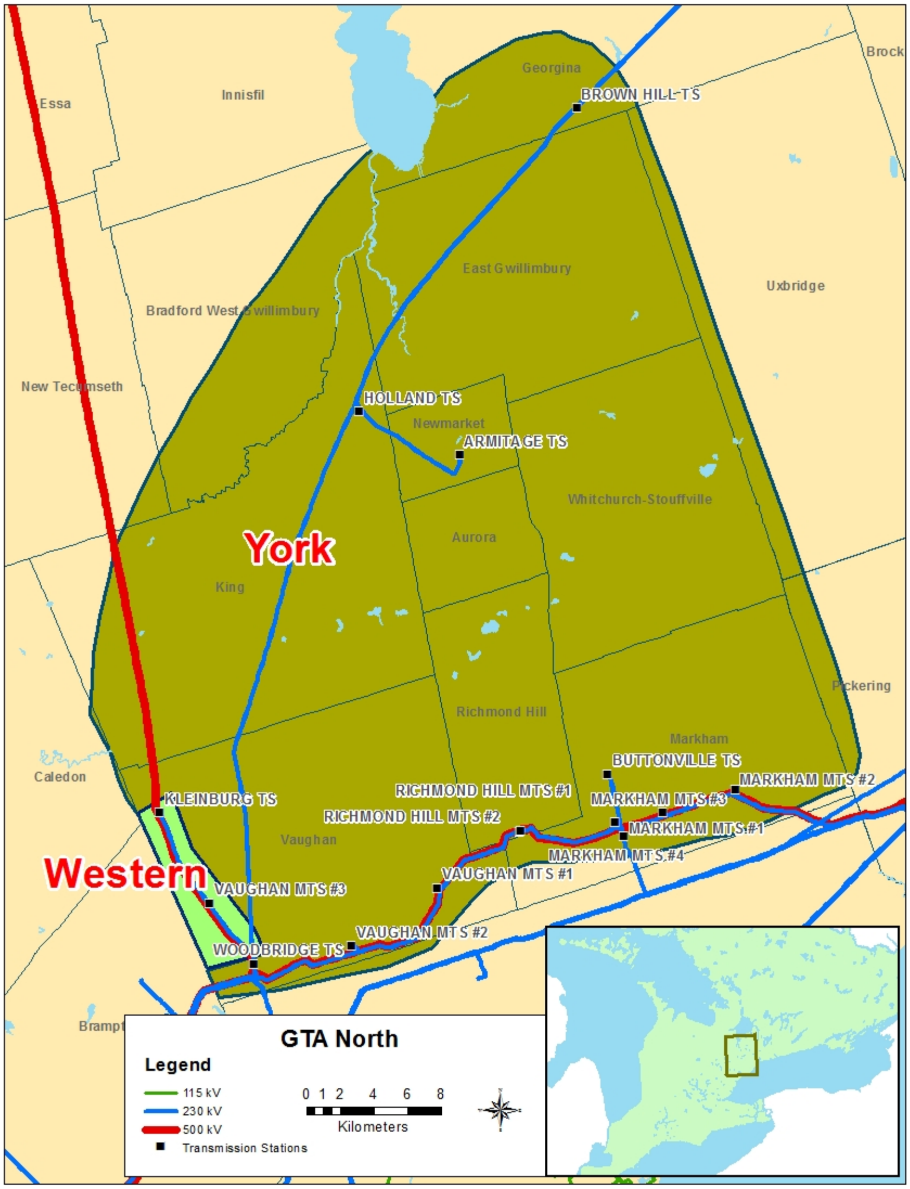

Figure 1: GTA North Region – Supply Areas

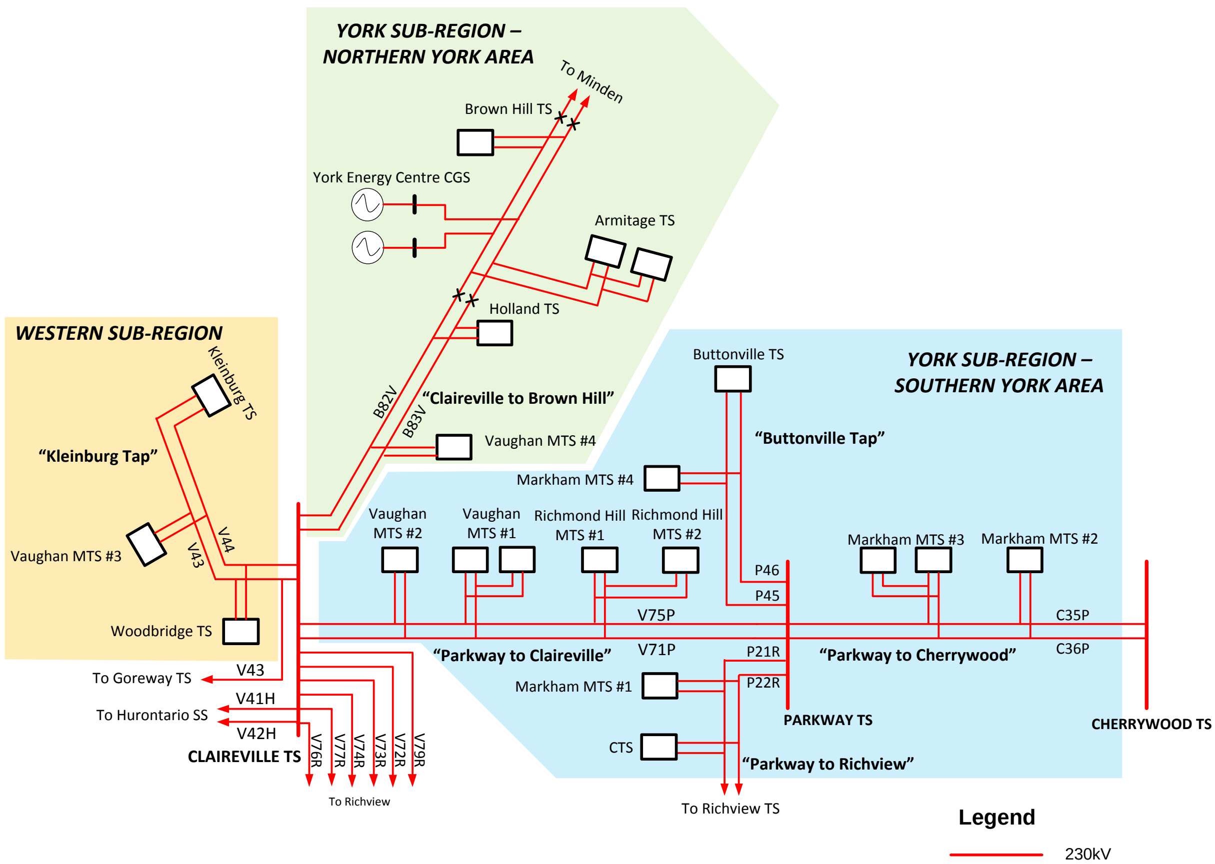

Figure 2: GTA North Transmission Single Line Diagram

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the GTA North Region NA. The information provided includes the following:

- Load Forecast;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and,
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the GTA North Region

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

i. Load forecast: The LDCs provided a load forecast for the region. The IESO provided a simplified Conservation and Demand Management ("CDM") and Distributed Generation ("DG") assumptions to determine their high-level impact on needs in the region. A GTA North Region extreme summer weather coincident peak gross load forecast was produced by translating the LDC load forecast into load growth rates and applying onto the 2017 actual summer station coincident peak load, adjusted for extreme weather conditions (according to Hydro One's methodology). The CDM and DG assumptions were applied to this gross forecast to produce the net forecast. The extreme summer weather coincident peak net load forecast for the individual stations in the GTA North Region is given in Appendix A. A similar approach was used to develop the GTA North Region extreme summer weather non-coincident peak gross and net load forecast. It should be noted that the actual versus forecasted year to year demand can vary due to factors such as weather, economic development, etc.

ii. Relevant information regarding system reliability and operational issues in the region;

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of their useful life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

Technical assessment of needs was based on:

i. Station capacity and Transmission Adequacy assessment

ii. System reliability and operation assessment

iii. End-of-life equipment: Major high voltage equipment reaching the end of its useful life with respect to replacing it with similar type equipment versus other options to determine the most optimal, resilient, and economic outcome.

Note that the Region is summer peaking so the assessment is based on summer peak loads.

7 NEEDS

This section describes emerging needs that have been identified in the GTA North Region since the previous regional planning cycle and reaffirms the near, mid, and long-term needs already identified in the previous RIP and IRRP. The needs are summarized in Tables 2 and 3 below:

Table 2: New Needs

New Needs	Discussed in Section
End-of-Life Equipment – Woodbridge TS T5 transformer	7.1.1
Load Restoration – P45+P46 ("Buttonville Tap")	7.1.2

Table 3: Needs Identified in Previous RIP and IRRP(1)

Needs Identified in Previous RIP and IRRP	Discussed in Section	RIP Report Section
Load Restoration – V43+V44 ("Kleinburg Tap")	7.2.1	7.3.1
Load Security on V71P/V75P – Parkway to Claireville	7.2.2	7.1.2
Vaughan Transformation Capacity	7.2.3	7.1.3
Markham Transformation Capacity	7.2.4	7.1.4
Station Service Supply to York Energy Centre (YEC)	7.2.5	7.2.1
Northern York Area Transformation Capacity	7.2.6	7.2.2

(1) Includes needs identified in the previous RIP and IRRP that do not have final plans underway yet

7.1 New Needs

7.1.1 End-Of-Life (EOL) Equipment Needs

Hydro One has identified the following major high voltage equipment to be reaching the end of their useful life over the next 10 years. Based on the equipment condition assessment, this asset has been identified to be in poor condition and approaching the end of its useful life.

Table 4: End-of-Life Equipment – GTA North Region

EOL Equipment(1)	Replacement Timing(2)
Woodbridge TS: T5 Transformer	2022-2023

(1) No other major HV station equipment or lines in the GTA North region have been identified for replacement/refurbishment at this time
(2) The replacement/refurbishment timing and prioritization are subject to change

The end-of-life equipment assessment for the above asset considered the following options:

1. Maintaining the status quo
2. Replacing equipment with similar equipment with *lower* ratings and built to current standards
3. Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
4. Eliminating equipment by transferring all of the load to other existing facilities
5. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement)
6. Replacing equipment with *higher* ratings and built to current standards

Woodbridge TS

Woodbridge TS comprises one DESN unit, T3/T5 (75/125 MVA), with two secondary winding voltages at 44 kV and 28 kV, each with a summer 10-Day LTR of 80 MW. The station's 2017 actual non-coincident summer peak load (adjusted for extreme weather) was 156 MW. Transformer T5 is currently about 45 years old and has been identified to be at its EOL. The companion DESN transformer, T3, is about 29 years old and is not at its EOL. Woodbridge TS supplies both Alectra and THESL.

The 44kV and 28kV load at Woodbridge TS is forecasted to be over 80% and 90% of their respective LTRs in the near and medium term. The closest station is Vaughan MTS #3 (owned by Alectra) and its load is forecasted to be over 95% of its LTR in the medium term. Therefore, downsizing T5 and consolidating load within the station and/or with area stations is not a prudent or viable option given medium term load growth at these stations and based on its historical loading. It is also important to note that the station is configured as a dual secondary yard (230/44-28kV) and the standard lower rated unit has only one secondary. Consequently, replacing T5 with a lower rated unit would result in significant re-configuration of the station and greater cost compared to replacing the EOL transformer with a similar unit of same ratings. Moreover, downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will also be significantly more costly. For example it may cost an additional $5-$10 million for the replacement of the transformer plus the incremental cost for the LDC to reconfigure feeders at a later stage. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions through load transfers.

With respect to maintaining status quo, the T5 transformer is in poor condition so this is not an option due to the risk of equipment failure, customer outages, increased maintenance cost, and environmental impact. Upgrading T5 is also not an option since it's already at the maximum size.

Based on the above, the study team recommends that this need be addressed by Hydro One and affected LDCs to coordinate the replacement plan. Hydro One will keep the study team informed of the status of the plan if any major changes occur. The timing of replacement for the EOL equipment is 2022-2023.

7.1.2 Load Restoration – P45+P46 ("Buttonville Tap")

This load restoration need is based on the ORTAC load restoration criteria that requires any load loss exceeding 250 MW to be restorable within 30 minutes. Based on the extreme summer weather coincident peak net load forecast, for the loss of 230kV circuits, P45 and P46 (stations connected are Buttonville TS and Markham #4 MTS), the load interrupted by configuration is expected to exceed 250 MW beginning in 2021 and restoration within 30 minutes needs to be assessed.

It should also be noted that a new station, Markham #5 MTS, is being planned for connection to circuits P45 and P46, with a projected need date in the 2025-2026[1] timeframe and an initial load of 26 MW based on the extreme summer weather coincident peak net load forecast (see Section 7.2.4 for more details). This load should also be taken into account for the load restoration need analysis.

The study team recommends that further assessment and regional coordination in the IRRP and RIP phase is required to review options and identify a preferred restoration plan.

7.2 Needs Identified in Previous RIP and/or IRRP

The following section summarizes the needs identified in the previous 2016 GTA North RIP report and 2015 York Region IRRP that do not have final plans underway yet. The Study Team reaffirms these needs and an update is provided below.

7.2.1 Load Restoration – V43+V44 ("Kleinburg Tap")

The load restoration need for 230 kV radial circuits, V43 and V44 (supplying Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS), was identified during the previous NA for the GTA North Western Sub-Region and also in the Northwest GTA IRRP as load restoration times as per the ORTAC may not be met

[1] The need date will be further refined by Hydro One and Alectra through the project development process. Refer to section 7.2.4 for more details.

for the loss of V43 and V44. The study team recommended that this need be addressed in IESO's GTA West bulk system planning initiative.

The subsequent GTA West bulk system study did not address the restoration need. As a result, the study team recommends that the need be revisited as part of the next GTA North IRRP.

7.2.2 Load Security on V71P/V75P – Parkway to Claireville

In the previous York Region IRRP, the study team recommended the installation of inline switches at the Vaughan MTS #1 junction in order to improve the capability of the system to restore load in the event that both 230 kV circuits V71P/V75P are lost. While the installation of these switches will improve the load restoration capabilities and overall reliability on the Parkway to Claireville corridor, it does not address the load security need on V71P/V75P.

Since the previous GTA North RIP, the IESO completed an addendum to its expedited SIA for the in-line switches at Grainger Junction project. The addendum indicated that an exemption for this project with respect to the 600 MW load security limit would not be required. However, it advised that the load security issue on the Parkway to Claireville corridor must be re-assessed as part of the next regional planning cycle.

The Study Team reassessed the load security issue during this regional planning cycle. Based on the extreme summer weather coincident peak net load forecast, the load on the Parkway to Claireville corridor is around 695 MW, which is lower than the previous RIP forecast (refer to RIP report, Appendix D), however continues to exceed the 600 MW limit. As a result, the study team reaffirms this need and recommends further assessment and regional coordination in the next IRRP and RIP phase to review options and develop a preferred plan.

7.2.3 Vaughan Transformation Capacity

In the previous RIP, the study team recommended that the need for additional transformation capacity in Vaughan, along with associated transmission capacity[2], be further assessed in the next regional planning cycle and to refine the need timing as Alectra advised they were updating their load forecast and the need date may change (for more details, refer to section 7.1.3 of the RIP report). Based on the current extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is beyond 2027. If CDM savings are not achieved as forecasted, then the need date can be as early as 2027.

The Study Team reaffirms this need and recommends further assessment and regional coordination in the IRRP and RIP phase to review options and develop a preferred plan.

7.2.4 Markham Transformation Capacity

[2] There are long-term transmission supply needs associated with new transformation capacity

In the previous RIP, the study team recommended to continue the assessment of wires and non-wires options to address the need for additional transformation capacity in the Markham-Richmond Hill area and to refine the need timing. During the RIP, Alectra advised that they were updating their load forecast and the need date may change (for more details, refer to section 7.1.4 of the RIP report). In April 2017, the IESO issued a letter of support to Hydro One Transmission and Alectra to proceed with wires planning for a new 230/27.6kV DESN and the associated distribution and/or transmission lines to connect the new transformer station. In the hand-off letter, the IESO concluded that it is not feasible to rely entirely on distributed energy resources to defer the near-term supply need in the area and that a new station and associated connection lines would be required by 2023 to meet the growth projections in the Markham-Richmond Hill area. Based on the current extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is projected to be in the 2025-2026[3] timeframe. If CDM savings are not achieved as forecasted, then the need date can be as early as 2024.

The Study Team reaffirms this need and Hydro One and Alectra are currently in the process of selecting a preferred location to connect to 230 kV circuits P45/P46. Following this, Hydro One will proceed with development and estimate work to meet the need date. Further updates will be included in the next IRRP and RIP.

7.2.5 Station Service Supply to York Energy Centre

In the previous RIP, a need for addressing station service supply to York Energy Centre (currently supplied from Holland TS) in the event of a (i) low-voltage breaker failure at Holland TS or (ii) double circuit 230 kV contingency was identified (for more details, refer to section 7.2.1 of the RIP report). These events can result in an interruption to the station service supply to York Energy Centre and therefore the loss of all generation output until the station service can be restored from the alternate source.

Since the RIP, the IESO completed a System Impact Assessment (SIA) for the new 230 kV in-line breakers at Holland TS and it found that the use of load rejection will no longer be a suitable means to address (i) and (ii) in the near to medium term as the amount of load rejection required to address overloads and voltage collapse will exceed the permissible amount of 150 MW allowed by ORTAC load security criteria.

The Study Team reaffirms this need and recommends further assessment and regional coordination in the IRRP and RIP phase to review options and develop a preferred plan.

7.2.6 Northern York Area Transformation Capacity

In the previous RIP, the study team recommended that the need for additional transformation capacity in the Northern York Area, along with associated transmission capacity[4], be further assessed in the next regional planning cycle (for more details, refer to section 7.2.2 of the RIP report). Based on the current

[3] The need date will be further refined by Hydro One and Alectra through the project development process
[4] There are long-term transmission supply needs associated with new transformation capacity

extreme summer weather non-coincident peak net load forecast, the combined loading on Armitage TS and Holland TS will not exceed their combined summer 10-Day LTR during the study period (combined load is over 97% of its combined LTR in 2027). There is 44 kV transfer capability between these stations on the distribution system so the timing of the need is based on the combined capability of both stations. However, if CDM savings are not achieved as forecasted, then the need date may be as early as 2024.

The Study Team reaffirms this need and recommends further assessment and regional coordination in the IRRP and RIP phase to review options and develop a preferred plan.

8 RECOMMENDATIONS

The Study Team's recommendations to address the needs identified are as follows:

a) Further regional coordination is not required to address the EOL Woodbridge TS T5 transformer (discussed in sections 7.1.1). From a cost, loading, station configuration, and customer connection needs perspective, this asset should not be eliminated or have its capacity reduced. The study team recommends that this EOL need be addressed by Hydro One and affected LDCs to coordinate the replacement plan. Hydro One will keep the study team informed of the status of the plan if any major changes occur.

b) As per the IESO's letter of support in April 2017, Alectra and Hydro One will continue to develop a new 230/27.6kV DESN in the Markham-Richmond Hill area (discussed in section 7.2.4). Further updates will be included in the next IRRP and RIP.

c) Further assessment and regional coordination is required in the IRRP and/or RIP, to develop a preferred plan for the following needs:

- Load Restoration – P45+P46 (discussed in Section 7.1.2)
- Load Restoration – V43+V44 (discussed in Section 7.2.1)
- Load Security on V71P/V75P – Parkway to Claireville (discussed in Section 7.2.2)
- Vaughan Transformation Capacity (discussed in Section 7.2.3)
- Station Service Supply to York Energy Centre (discussed in Section 7.2.5)
- Northern York Area Transformation Capacity (discussed in Section 7.2.6)
- Transmission Supply Capacity in Vaughan and Northern York Area in long term (discussed in sections 7.2.3 and 7.2.6)

The table below summarizes the above recommendations.

Table 5: Summary of Recommendations

Further Regional Coordination Not Required	Further Regional Coordination Required
EOL Station Equipment: • Woodbridge TS: T5	**Load Restoration:** • P45+P46 (Buttonville TS, Markham #4 MTS,

Further Regional Coordination Not Required	Further Regional Coordination Required
IESO Letter of Support: • Markham Transformation Capacity (Markham #5 MTS)	and future Markham #5 MTS) • V43+V44 (Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS) **Load Security:** • V71P/V75P (Parkway to Claireville) **Transformation Capacity:** • Vaughan #5 MTS • Northern York Area **Station Service Supply:** • York Energy Centre **Transmission Supply Capacity (long term)** • Vaughan #5 MTS • Northern York Area

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Appendix A: GTA North Region Load Forecast (2017 to 2027)

Stations Net Coincident Peak Load Forecast (MW)

Station Name	LTR*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Kleinburg TS (28kV)	97	55	51	52	52	52	52	52	52	52	52	51
Kleinburg TS (44kV)	99	87	83	83	84	84	84	85	84	84	84	83
Vaughan MTS #3 (28kV)	153	162	124	140	147	147	146	146	145	144	142	147
Woodbridge TS (44kV)	80	45	46	47	47	47	47	47	47	46	46	45
Woodbridge TS (28kV)	80	85	71	70	69	69	69	70	69	68	68	67
Holland TS (44kV)	168	126	123	128	132	136	137	139	140	141	140	141
Armitage TS (44kV)	317	265	262	266	270	274	278	282	285	287	288	291
Brown Hill TS (44kV)	184	49	47	47	48	48	49	50	50	50	50	50
Richmond Hill MTS (28kV)	254	256	232	229	236	244	243	242	249	254	254	254
Vaughan MTS #1 (28kV)	306	302	257	254	253	270	276	291	289	287	284	294
Vaughan MTS #2 (28kV)	153	113	124	131	139	147	146	146	145	144	142	147
Vaughan MTS #4 (28kV)	153	0	44	52	69	78	110	127	145	144	142	147
Vaughan MTS #5 (28kV)**	153	0	0	0	0	0	0	0	0	0	0	0
Buttonville TS (28kV)	166	126	123	136	136	141	141	140	139	138	137	136
Markham MTS #1 (28kV)	81	78	80	79	78	78	78	77	80	81	81	81
Markham MTS #2 (28kV)	101	114	92	98	97	97	96	96	99	101	101	101
Markham MTS #3 (28kV)	202	154	197	196	194	193	193	192	198	202	202	202
Markham MTS #4 (28kV)	153	70	89	91	104	112	129	146	150	153	153	153
Markham MTS #5 (28kV)	153	0	0	0	0	0	0	0	0	26	86	77

* LTR based on 0.9 power factor

** Based on the non-coincident net forecast, the need date for Vaughan MTS #5 is beyond 2027.

Stations Net Non-Coincident Peak Load Forecast (MW)

Station Name	**LTR***	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Kleinburg TS (28kV)	97	62	59	59	59	59	59	59	59	59	59	58
Kleinburg TS (44kV)	99	87	83	83	84	84	84	85	84	84	84	83
Vaughan MTS #3 (28kV)	153	162	124	140	147	147	146	146	145	144	142	147
Woodbridge TS (44kV)	80	64	66	68	67	67	67	67	66	66	65	65
Woodbridge TS (28kV)	80	92	77	76	75	75	75	76	75	74	74	73
Holland TS (44kV)	168	132	128	134	138	142	144	145	146	147	147	147
Armitage TS (44kV)	317	295	291	296	300	304	309	313	316	318	319	323
Brown Hill TS (44kV)	184	78	75	75	77	77	78	80	80	80	80	80
Richmond Hill MTS (28kV)	254	256	232	229	236	244	243	242	249	254	254	254
Vaughan MTS #1 (28kV)	306	302	257	254	253	270	276	291	289	287	284	294
Vaughan MTS #2 (28kV)	153	113	124	131	139	147	146	146	145	144	142	147
Vaughan MTS #4 (28kV)	153	0	44	52	69	78	110	127	145	144	142	147
Vaughan MTS #5 (28kV)**	153	0	0	0	0	0	0	0	0	0	0	0
Buttonville TS (28kV)	166	135	132	146	146	152	151	151	150	148	147	145
Markham MTS #1 (28kV)	81	78	80	79	78	78	78	77	80	81	81	81
Markham MTS #2 (28kV)	101	114	92	98	97	97	96	96	99	101	101	101
Markham MTS #3 (28kV)	202	154	197	196	194	193	193	192	198	202	202	202
Markham MTS #4 (28kV)	153	70	89	91	104	112	129	146	150	153	153	153
Markham MTS #5 (28kV)	153	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26	86	77

* LTR based on 0.9 power factor
** Based on the non-coincident net forecast, the need date for Vaughan MTS #5 is beyond 2027.

Appendix B: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TPS	Traction Power Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme
YEC	York Energy Centre

Metro Toronto

REGIONAL INFRASTRUCTURE PLAN

January 12, 2016

hydro one

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Enersource Hydro Mississauga
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
PowerStream Inc.
Toronto Hydro-Electric System Limited
Veridian Connections Inc.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE WORKING GROUP IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE METRO TORONTO REGION.

The participants of the RIP Working Group included members from the following organizations:

- Enersource Hydro Mississauga
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- PowerStream Inc.
- Toronto Hydro-Electric System Limited ("THESL")
- Veridian Connections Inc.
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the regional planning process and it follows the completion of the Central Toronto Sub-Region's Integrated Regional Resource Plan ("IRRP") by the IESO in April 2015 and the and Metro Toronto Northern Sub-Region's Needs Assessment ("NA") Study by Hydro One in June 2014.

This RIP provides a consolidated summary of needs and recommended plans for both the Central Toronto Sub-Region and Metro Toronto Northern Sub-Region that make up the Metro Toronto Region.

The Central Toronto IRRP has identified longer term needs beyond 2025. These longer term needs are also reviewed and discussed in this report. However, as the need dates are beyond 2025, adequate time is available to develop a preferred alternative in the next planning cycle expected to be started in 2018.

The major infrastructure investments planned for the Metro Toronto Region over the near and mid-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost ($M)
1	Manby Autotransformer Overload Protection Scheme	2018	$2
2	Runnymede TS Expansion & Manby x Wiltshire Corridor Upgrade	2019	$90
3	Horner TS Expansion	2020	$53
4	Richview x Manby Corridor Upgrade	2020	$20-40
5	Copeland MTS Phase 2	2020+	$46

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. As mentioned above, the next planning cycle is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE METRO TORONTO REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") on behalf of the Working Group that consists of Hydro One, Enersource Hydro Mississauga, Hydro One Networks Inc. Distribution, the Independent Electricity System Operator ("IESO"), PowerStream Inc., Toronto Hydro-Electric System ("THESL"), and Veridian Connections Inc. in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The Metro Toronto Region is comprised of the City of Toronto. Electrical supply to the Region is provided by thirty five 230kV and 115kV transmission and step-down stations as shown in Figure 1-1. The eastern, northern and western parts of the Region are supplied by eighteen 230/27.6kV step-down transformer stations. The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS) and fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The summer 2015 area load of the Metro Toronto region was about 4700MW.

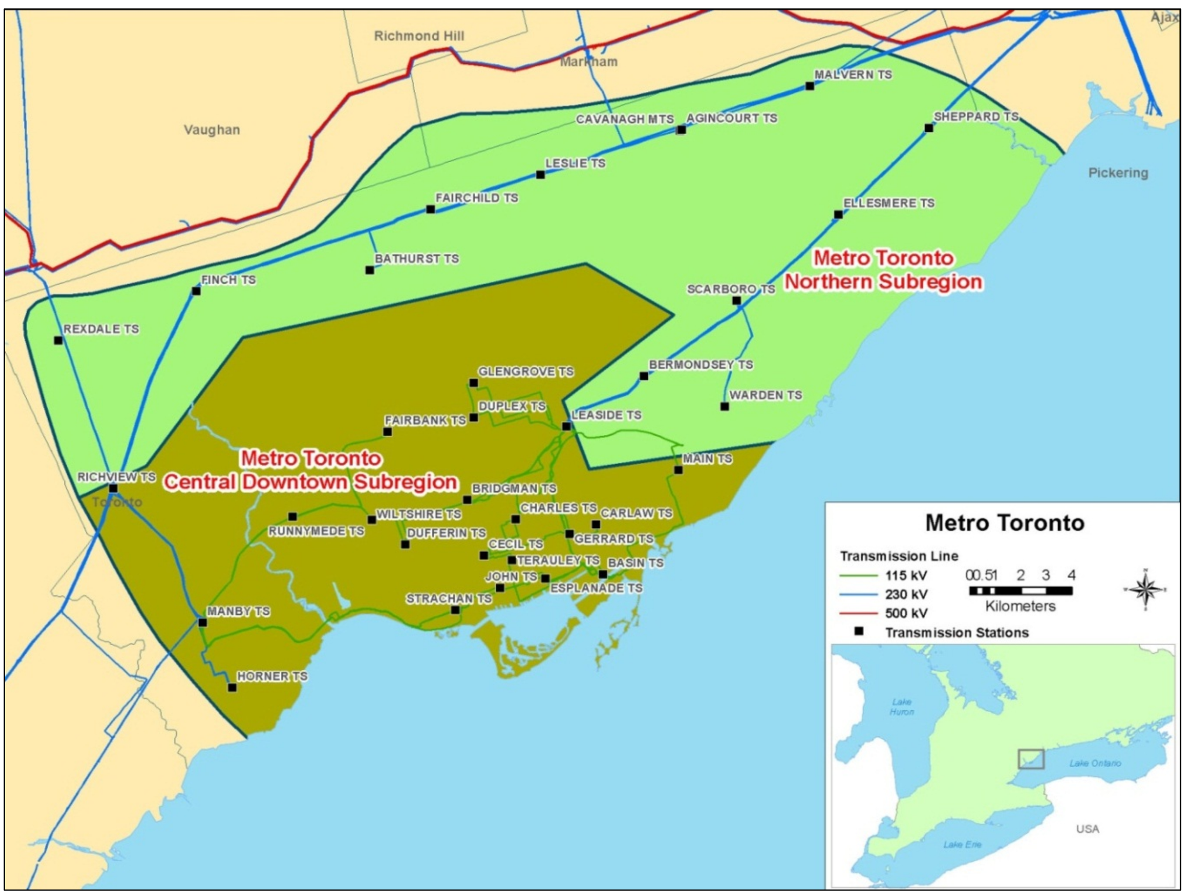

Figure 1-1 Map of Metro Toronto Region

1.1 Scope and Objectives

This RIP report examines the needs in the Metro Toronto Region. Its objectives are to:

- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop a wires plan to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2015-2025) identified in previous planning phases (Needs Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2015-2025 period and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Working Group.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process;
- Section 3 describes the region;
- Section 4 describes the transmission work completed over the last ten years;
- Section 5 describes the load forecast used in this assessment;
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the needs;
- Section 7 discusses the needs and provides the alternatives and preferred solutions;
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend

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[1] Also referred to as Needs Screening.

a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee (LAC) in the region or sub-region. For the Metro Toronto Region, community engagement through a formal LAC is on-going.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

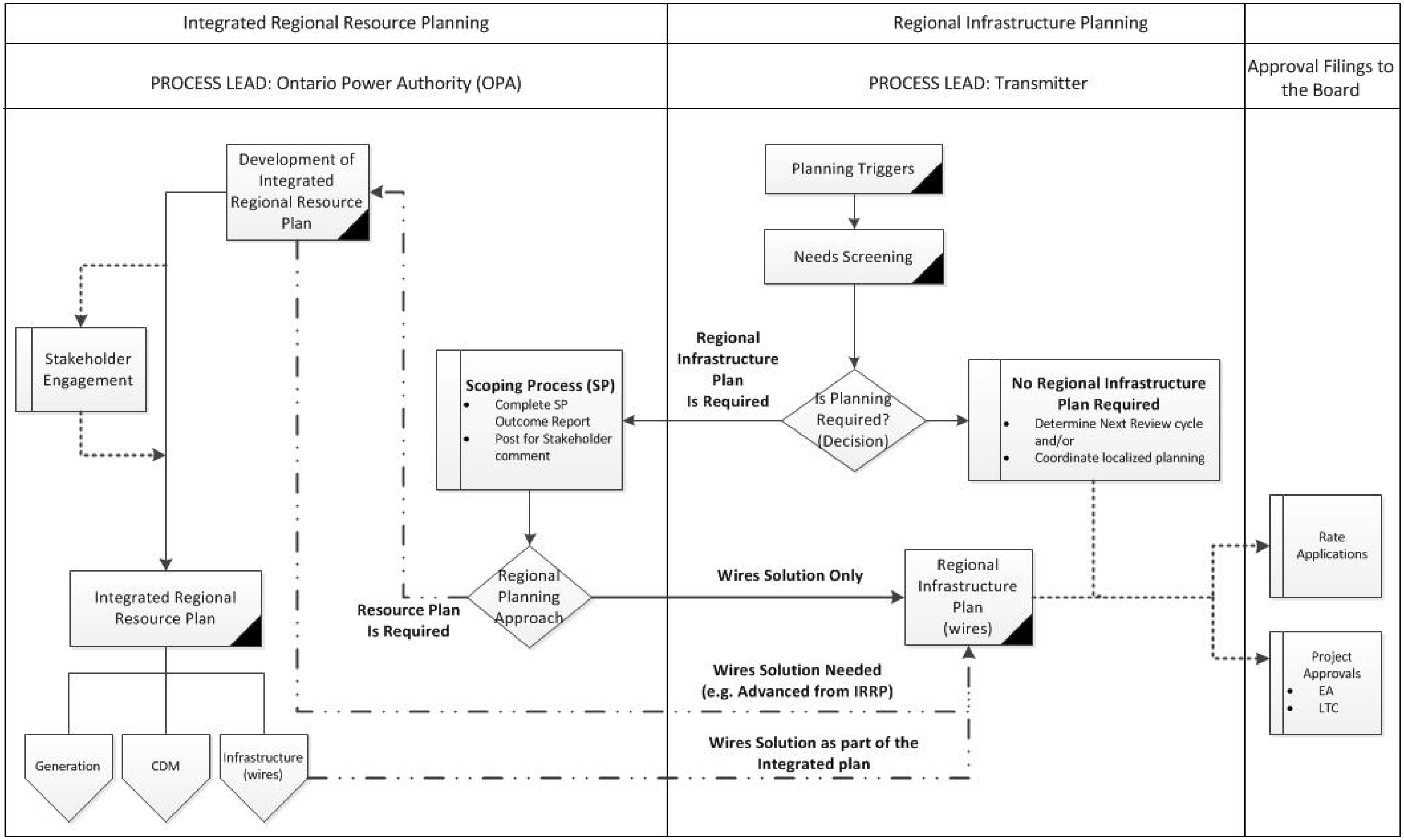

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (see Figure 2-2) as follows:

1) Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.
3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

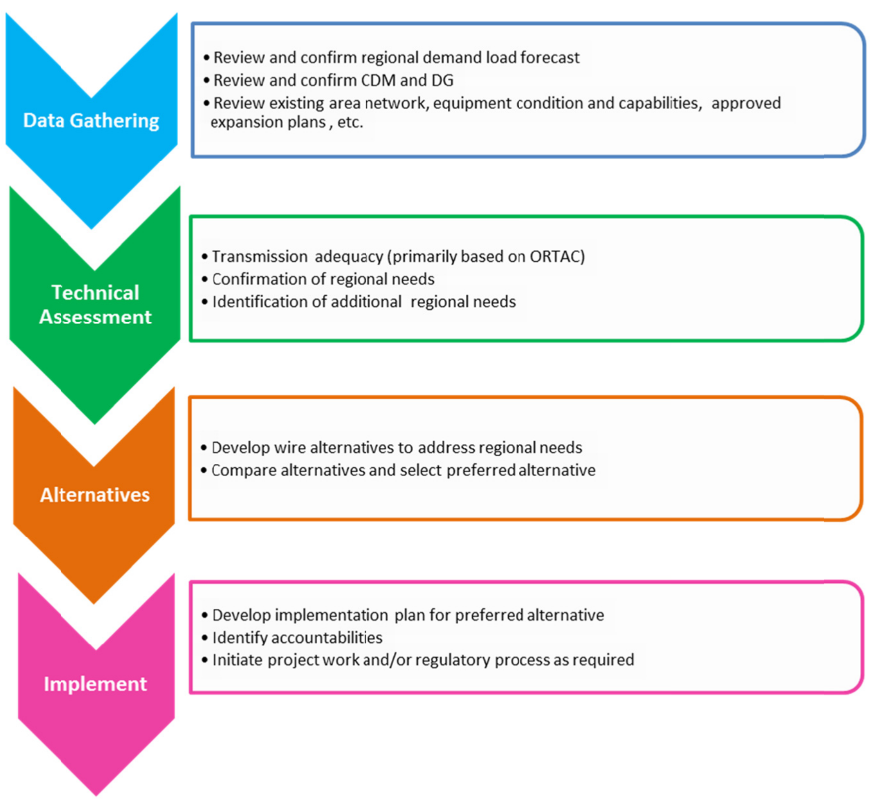

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE METRO TORONTO REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY LAKE ONTARIO ON THE SOUTH, STEELES AVENUE ON THE NORTH, HIGHWAY 427 ON THE WEST AND REGIONAL ROAD 30 ON THE EAST. IT CONSISTS OF THE CITY OF TORONTO, WHICH IS THE LARGEST CITY IN CANADA AND THE FOURTH LARGEST IN NORTH AMERICA.

Bulk electrical supply to the Metro Toronto Region is provided through three 500/230 kV transformers stations - Claireville TS, Cherrywood TS and Parkway TS and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. Local generation in the area consists of the 550 MW Portlands Energy Centre located near downtown area and connected to the 115 kV network at Hearn Switching Station. The Metro Toronto Region 2015 peak summer demand was about 4700MW which represents about 20% of the gross electrical demand in the province.

Toronto Hydro-Electric System Limited (“THESL”) is the Local Distribution Company (“LDC”) that serves the electricity demands for the city of Toronto. Other LDCs supplied from electrical facilities in the Metro Toronto Region are Hydro One Networks Inc. Distribution, PowerStream Inc., Veridian Connections Inc., and Enersource Hydro Mississauga. The LDCs receive power at the step down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

The April 2015 Integrated Regional Integrated Regional Resource Plan (“IRRP”) report, prepared by the IESO in conjunction with Hydro One and the LDC, focused on the Central Toronto Area which included the 115kV network and the 230kV facilities in the western part of Region. The June 2014 Metro Toronto Northern Sub-Region Needs Assessment report, prepared by Hydro One, considered the remainder of the Metro Toronto region. A map and a single line diagram showing the electrical facilities of the Metro Toronto Region, consisting of the two sub-regions, is shown in Figure 3-1 and Figure 3-2 respectively. Please note that the facilities shown include the new Leaside TS to Bridgman TS 115kV circuit L18W and the new Copeland MTS. The L18W circuit is being built as part of the Midtown Transmission Reinforcement Project and Copeland MTS is a new THESL owned transformer station to serve the downtown area. Work on these projects is in the advanced stage and both are expected to come into service in 2016.

3.1 Central Toronto Sub-Region

The Central Toronto Sub-Region includes the area extending northward from Lake Ontario to roughly Highway 401, westward to Highway 427 and Etobicoke Creek, and eastward to Victoria Park Avenue.

The Central Toronto Sub-Region was identified as a “transitional” region, as planning activities in the region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. An IRRP for the region was completed in April 2015.

The Central Toronto Sub-region is further subdivided into two areas:

- The Richview Manby 230kV area: This includes the former borough of Etobicoke and is served by the Richview TS to Manby TS 230kV circuits. The area has two 230/27.6kV step-down transformer stations. The coincident peak summer 2015 area load was about 320 MW.
  The Richview TS to Manby 230kV circuits together with the Richview TS to Cooksville TS circuit R24C supply a number of stations in the GTA West Southern Sub-Region. These stations while outside the Metro Toronto Region have therefore been included in Figure 3-2.

- The Central 115kV Area: The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS), fifteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The area includes the downtown core including the financial, entertainment and educational districts. The 2015 summer coincident area load was about 1900MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

3.2 Metro Toronto Northern Sub-Region

The Metro Toronto Northern Sub-Region comprises the remainder of the Metro Toronto region. It includes the area roughly bordered geographically by Highway 401 on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east in addition to the area east of the Don Valley Parkway and north of O'Connor Dr.

Electrical supply to the Metro Toronto Northern Sub-Region is provided through 230 kV transmission lines and step-down transformation facilities. Supply to this sub-region is provided from a 230 kV transmission system consisting of the Richview TS to Parkway TS, the Richview TS to Cherrywood TS, the Richview TS to Claireville TS, as well as the Cherrywood TS to Leaside TS 230kV transmission system. The area is served primarily at 27.6kV by fifteen step-down transformer stations with a pocket of 13.8kV load supplied from Leaside TS and Leslie TS. The 2015 summer coincident area load was about 2500 MW.

Please see Figure 3-1 and 3-2 for a map and single line diagram of the Sub-Region facilities.

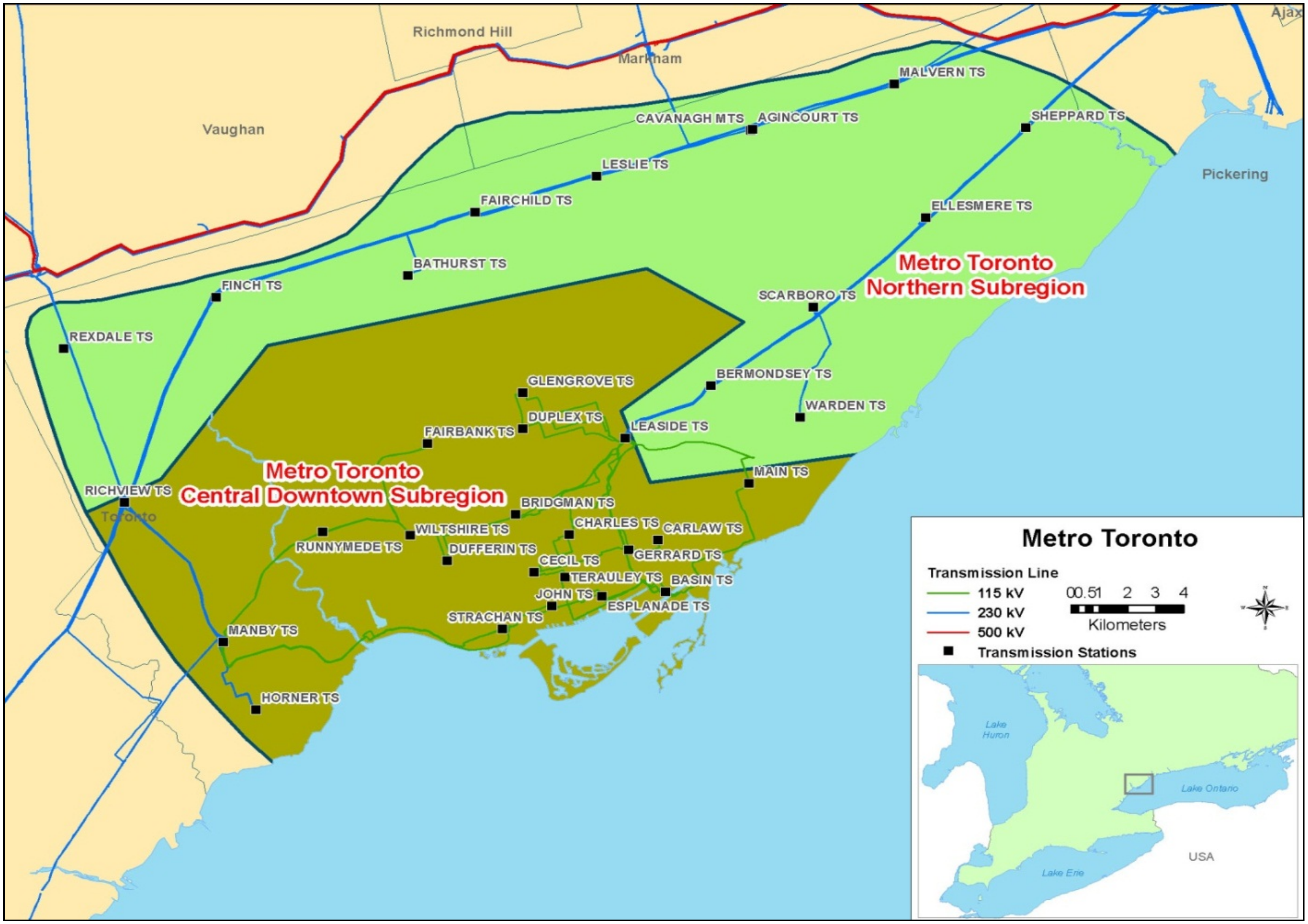

Figure 3-1 Metro Toronto Region – Supply Areas

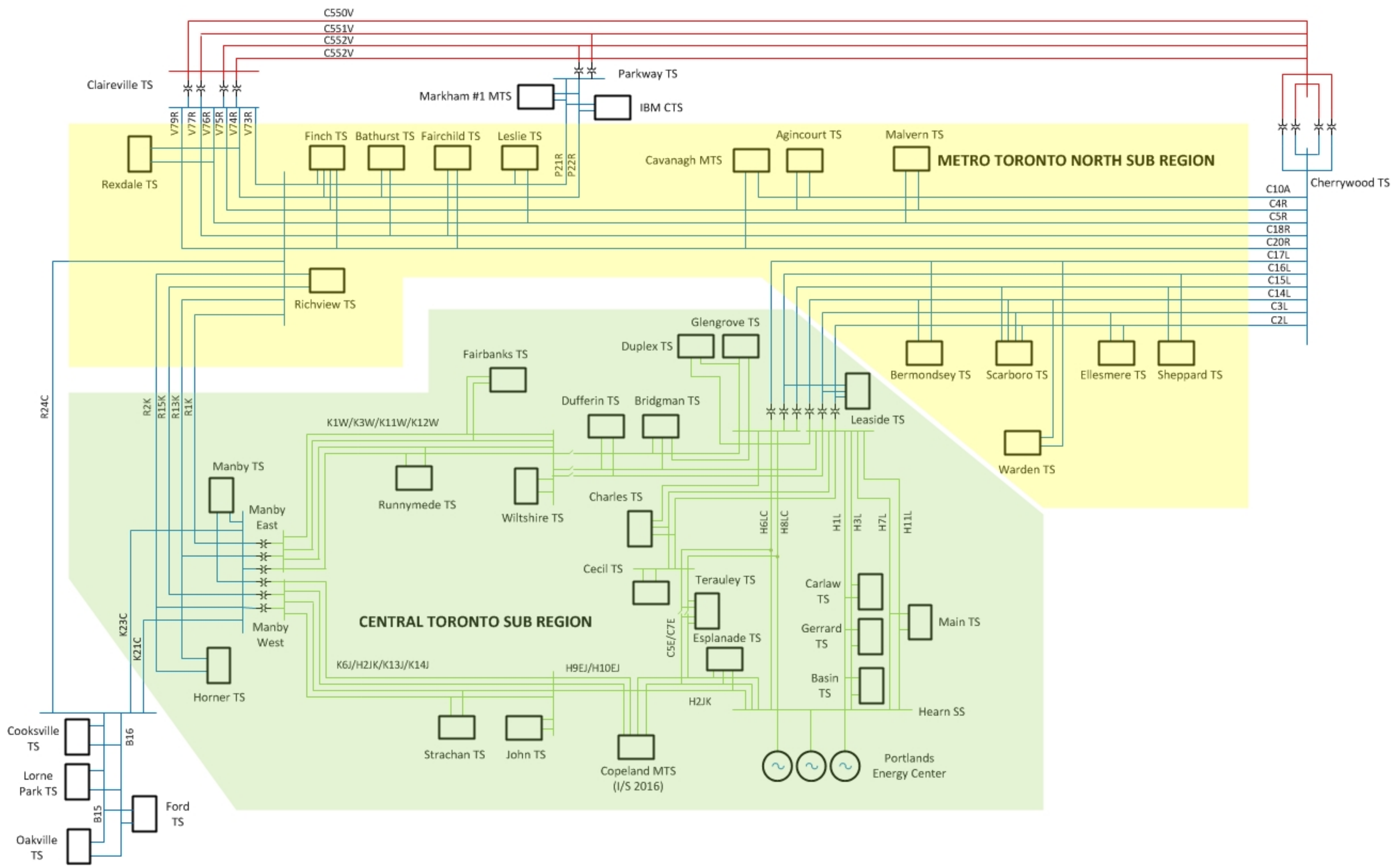

Figure 3-2 Metro Toronto Region – Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED AND/OR UNDERWAY OVER THE LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE METRO TORONTO REGION IN GENERAL AND THE TORONTO 115 KV NETWORK IN PARTICULAR.

These projects together with the new 550 MW Portlands Energy Centre that went into service in 2009 have ensured that the City continues to receive adequate and reliable supply. A brief listing of these projects is given below:

- Parkway 500/230 kV TS (2005) – built to provide adequate 500/230 kV transformation capacity following the retirement of Lakeview GS. The station while just outside the Metro Toronto Region is a key contributor in ensuring supply adequacy to the Region.

- John TS to Esplanade TS underground cable circuits (2008) – built to provide transfer capability between the Leaside TS and the Manby TS 115 kV areas.

- Incorporation of the 550 MW Portlands Energy Centre (2009) – covered modification to the Hearn 115kV switchyard to connect the new generation.

- 115 kV Switchyard Work at Hearn SS, Leaside TS & Manby TS (2013 & 2014) – covered replacement of the aging 115 kV switchyard at Hearn SS with a new GIS switchyard and replacement of all 115 kV breakers at Leaside TS and Manby TS.

- Manby 230 kV Reconfiguration (2014) – re-tapped Horner TS from the circuit R15K to R13K at Manby TS to balance / improve the distribution of loading on the 230 kV Richview TS to Manby TS system.

- Lakeshore Cable Refurbishment project (2015) – covered replacement of the aging K6J/H2JK 115 kV circuits between Riverside Jct. and Strachan TS.

- Midtown Transmission Reinforcement Project (expected completion by 2016) – covered replacement of the aging L14W underground cable and building an additional fourth 115 kV circuit between Leaside TS and Bridgman TS.

- Clare R. Copeland 115kV switching station (expected completion by 2016) – built to connect a new THESL owned 115/13.8 kV step-down transformer station in the downtown district.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the Metro Toronto Region is forecast to increase at an average rate of approximately 0.9% annually up to 2020, at 0.67% between 2020 and 2025 and at 0.61% beyond 2025. The growth rate varies across the region – from about 0.35% in the Northern Sub-Region to 1.07% in the City's downtown area over the 20 years.

Figure 5-1 shows the Metro Toronto Region's planning load forecast (summer net, non-coincident and regional-coincident extreme weather peak) under the IRRP high growth scenario. The regional-coincident (at the same time) forecast represents the total peak load of the 35 step-down transformer stations in the Metro Toronto. The coincident regional peak load is forecast to increase from 5176 MW in 2015 to 6196 MW by 2035.

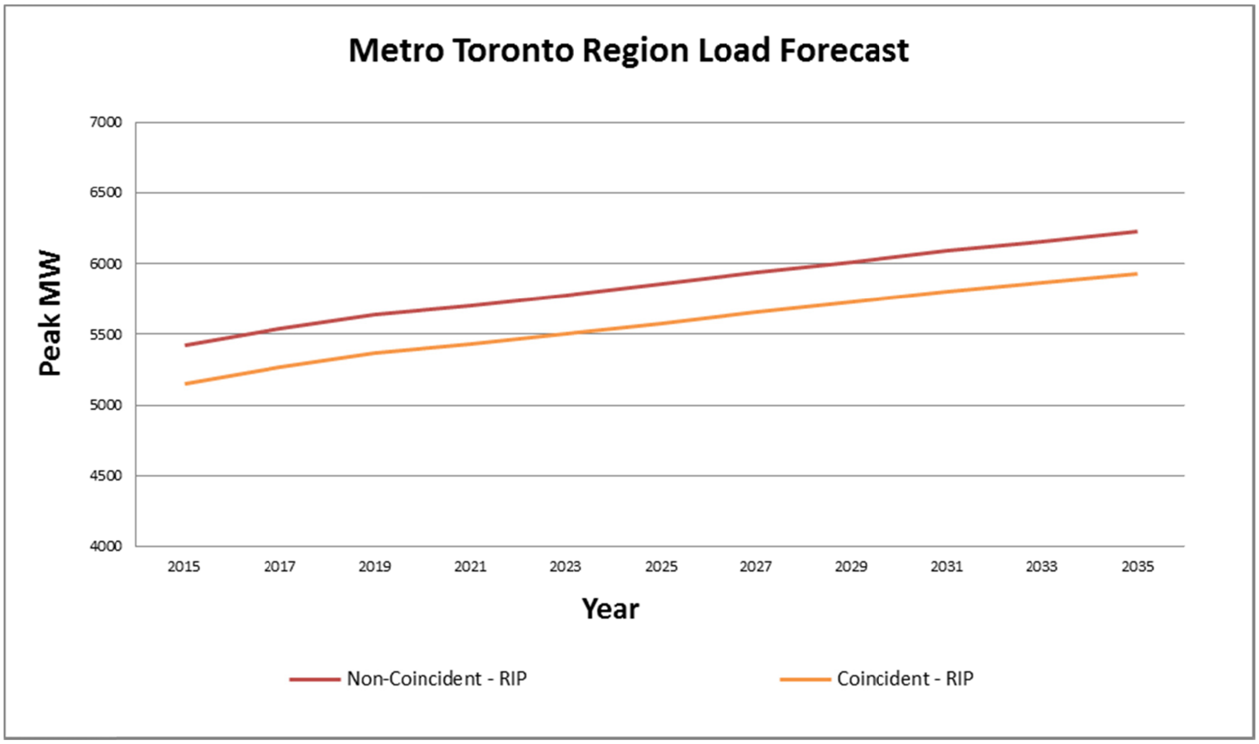

Figure 5-1 Metro Toronto Region Summer Extreme Weather Peak Forecast

The coincident and non-coincident extreme weather peak load forecast for the individual stations in the Metro Toronto Region is given in Appendix D. The coincident forecast represents the sum of the area stations peak load at the time of Metro Toronto Region peak demand and represents loads that would be seen by transmission lines and autotransformer stations and is used to determine the need for additional line and auto-transformation capacity. The non-coincident forecast represents the sum of the individual stations peak load and is used to determine the need for station capacity.

The individual station forecasts were developed by projecting 2015 summer peak loads, corrected for extreme weather, using the area stations growth rates as per the 2015 IESO's IRRP study (High Demand Scenario) for the Central Toronto Sub-Region [1] and as per the 2014 Hydro One's Need Assessment study [2] for the Metro Toronto Northern Sub-Region. The growth rates from [1] only account for existing Distributed Generation ("DG"), and do not include any new CDM and DG. The growth rates from [2] are the net growth rates seen by station equipment and account for CDM measures and connected DG. Details on the CDM and connected DG are provided in [1] and [2] and are not repeated here.

Impact of Metrolinx Go Transit Electrification

In June 2015, Metrolinx advised Hydro One that they are planning to proceed with the electrification of the Go transit rail system. This information was provided after the IRRP was completed in April 2015. Under their plan three Traction Power Stations (TPS) are proposed to be built in the Metro Toronto Region. These stations are as follows:

- Mimico TPS – For the Lakeshore West Go Transit Line (2020)
- Cityview TPS – For the Pearson Airport and Kitchener Go Transit lines (2020)
- Warden TPS – For the Lakeshore East Go Transit Line (2020)

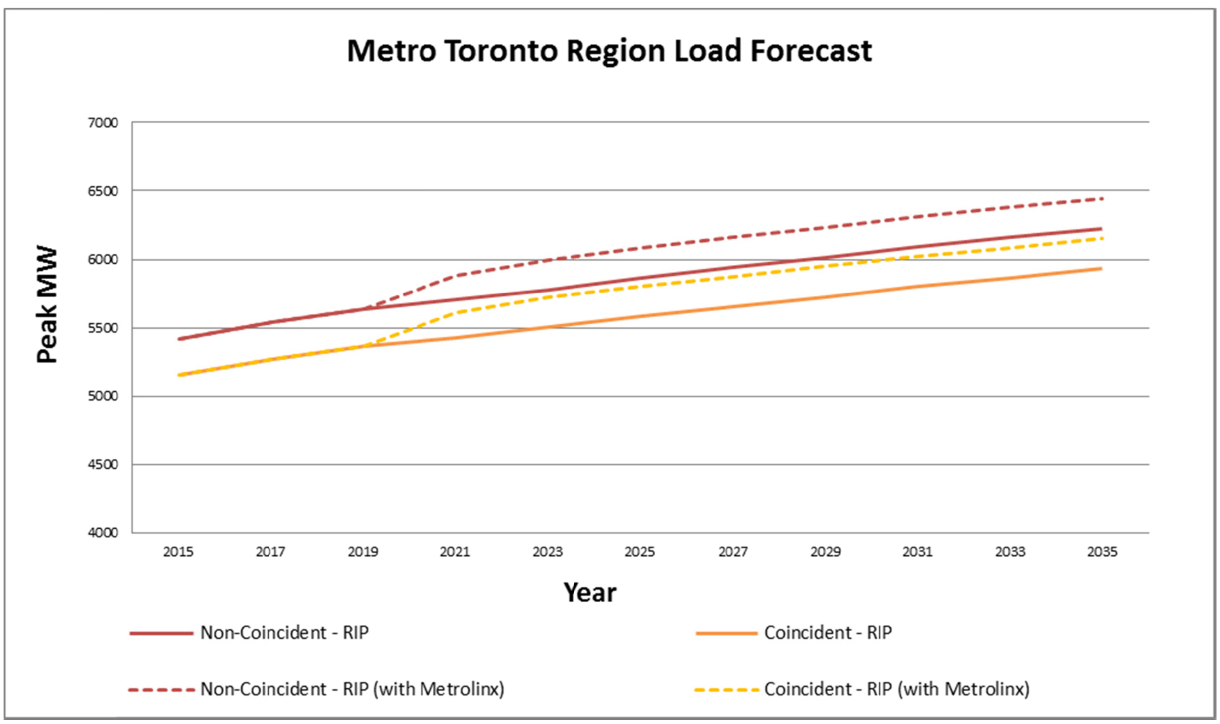

Figure 5-2 Effect of Metrolinx Electrification on the Metro Toronto Region Summer Peak Load

The impact of the Metrolinx load on the regional forecast is shown in Figure 5-2. Each of the three Metro area stations is expected to have an initial load of 40MW increasing to 80MW in 4 years. The net result is to increase the Region peak load by 240MW.

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP Assessments is 2015-2035.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low voltage capacitor banks. Normal planning supply capacity for transformer stations in this Sub-Region is determined by the summer 10-Day Limited Time Rating (LTR).
- For THESL 13.8kV stations, an additional 95% factor is applied to the normal planning supply capacity in this study. This is to reflect the fact that all the capacity cannot be effectively utilized due to the large relative size of the individual customer loads.

6. ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE METRO TORONTO REGION OVER THE 2015-2035 PERIOD. IT ASSUMES THAT ALL PROJECTS CURRENTLY UNDER WAY ARE IN SERVICE.

Within the current regional planning cycle two regional assessments have been conducted for the Metro Toronto Region. The findings of these studies are input to the RIP. The studies are:

1) IESO's Central Toronto Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Needs Assessment Report – Metro Toronto – Northern Sub-Region – June 11, 2014[2]

The IRRP and NA planning assessments identified a number of regional needs to meet the area forecast load demands. These regional needs are summarized in Table 6-1 and include needs for which work is already underway and/or being addressed by a LP study. A detailed description and status of work initiated or planned to meet these needs is given in Section 7.

A review of the loading on the transmission lines and stations in the Metro Toronto Region was also carried out as part of the RIP report using the latest Regional Forecast based on the IRRP high load growth scenario and as given in Section 5. The impact of Metrolinx Electrification on the regional infrastructure has been included.

For cases where a need was identified in the near or mid-term by the high growth scenario, a sensitivity analysis was done using the IRRP low growth scenario to get a range on the need date. Sections 6.1 to 6.2 present the results of this review. Additional needs identified as a result of the review are also listed in Table 6-1.

Table 6-1 Needs identified in Previous Stages of the Regional Planning Process

Type	Section	Needs	Timing
Station Capacity	7.1	West Toronto (Runnymede TS & Fairbank TS)	Today
	7.2	Southwest Toronto (Manby TS & Horner TS)	2020-2027
	7.3	Downtown District (JETC[1] Area)	2020+[2]
Transmission Line Capacity	7.4	230 kV Richview TS to Manby TS Corridor	2020-2023
	7.5	Circuit C10A (Duffin Jct. to Agincourt Jct.)	Completed
Supply Security, Reliability and Restoration	7.6	Breaker failure contingencies at Manby W and Manby E TS	2018/2021
	7.7	Breaker failure contingency at Leaside TS	Today
	7.8	Double circuit contingencies C2L/C3L or C16L/C17L (Cherrywood TS to Leaside TS)	2021
	7.9	Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)	Today
Long-Term	7.10	115 kV Manby West To Riverside Jct. Lines	2035+
		230/115 kV Manby TS transformer capacity	2035+
		230/115 kV Leaside TS transformer capacity	2026+
Additional Long-Term Need Identified in RIP	7.10	Leaside TS x Wiltshire TS circuits	2034

(1) JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.
(2) The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

6.1 Metro Toronto Northern Sub-Region

6.1.1 230kV Transmission Facilities

The Northern 230kV facilities consist of the following 230kV transmission circuits (Please refer to Figure 3-2):

a) Claireville TS to Richview TS 230kV circuits: V72R, V73R, V74R, V76R, V77R and V79R.
b) Cherrywood TS to Richview TS 230kV circuits: C4R, C5R, C18R and C20R.
c) Parkway TS to Richview 230kV circuits: P21R and P22R
d) Cherrywood TS to Agincourt TS 230kV circuit C10A.
e) Cherrywood TS to Leaside TS 230kV circuits: C2L, C3L C14L, C15L, C16L and C17L.

The Claireville TS to Richview TS circuits, the Cherrywood TS to Richview TS circuits and the Parkway TS circuits to Richview TS circuits carry bulk transmission flows as well as serve local area station loads within the Sub-Region. These circuits are adequate over the study period.

The Cherrywood TS to Agincourt TS circuit C10A is a radial circuit that supplies Agincourt TS and Cavanagh TS. The Need Assessment for the Metro Toronto Northern Sub-Region had identified that line capacity was restricted due to inadequate clearance from underbuilt street lighting and distribution line. Field surveys carried out by Hydro One have confirmed that the limiting underbuilds have been removed. The circuit is adequate over the study period.

The Cherrywood TS to Leaside TS 230kV circuits supply the Leaside TS 230/115kV autotransformers as well as serve local area load. Loading on these circuits is adequate over the study period.

6.1.2 Step-Down Transformer Station Facilities

The Sub-Region has the following step down transformer stations:

Agincourt TS	Leaside TS
Bathurst TS	Leslie TS
Bermondsey TS	Malvern TS
Cavanagh MTS	Rexdale TS
Ellesmere TS	Scarboro TS
Fairchild TS	Sheppard TS
Finch TS	Warden TS

The Metro Toronto Northern Sub-Region Needs Assessment Report had identified that the gross load was approaching station capacity at Cavanagh MTS and the Leslie TS (T1/T2, 27.6kV windings) and the Sheppard TS (T3/T4) DESN units. No action was recommended as the net load after considering the CDM and DG program is within ratings. The RIP report has reviewed the station loading and confirms that station capacity is adequate over the study period. However, the station loads will be monitored to ensure facility ratings are not exceeded.

6.2 Central Toronto Sub-Region

6.2.1 230kV Transmission Facilities

The 230kV transmission facilities in the Central Toronto Sub-Region are as follows (Please refer to Figure 3-2):

a) Richview TS x Manby TS 230kV circuits: R1K, R2K, R13K and R15K
b) Cooksville TS x Manby TS 230kV circuits: K21C/K23C
c) Manby TS 230/115kV autotransformers
d) Leaside TS 230kV/115kV autotransformers

The Richview TS to Manby TS circuits and the Cooksville TS to Manby TS circuits supply the Manby 230/115kV autotransformer station as well as Horner TS. Please note that the K21C and K23C circuits connect back to Richview TS through Cooksville TS and 230kV circuit R24C.

Table 6-2 summarizes the result of adequacy studies and gives the need date for transmission reinforcement for each of the above facilities.

Table 6-2 Adequacy of 230kV Transmission Facilities

Facilities	2015 MW Load(1)	MW Load Meeting Capability (LMC)	Limiting Contingency	Need Date
Richview x Manby 230kV Corridor	1456	1540	R2K	2020-2023(2)
Manby E. 230/115kV autos	330	560	T2	2035+
Manby W. 230/115kV autos	397	612	T9	2035+
Leaside 230/115kV autos + Portlands GS(1)	1340	1525-1915(3)	None	2026+(4)

(1) The loads shown have been adjusted for extreme weather.

(2) The 2020 and 2023 need dates correspond to the high growth and low growth rate scenarios without considering Metrolinx Mimico TPS. Assuming Metrolinx Mimico TPS comes into service in 2020, the need date will become 2020 under both scenarios.

(3) The Leaside 115kV area is supplied by the Leaside TS 230/115kV autotransformers and the 550MW Portlands GS. Load Meeting capability is dependent on the generation from Portlands GS which backs up the flow through the Leaside autotransformers. The 1525MW LMC assumes only 160MW generation at Portland GS while the 1915MW LMC assumes the full 550MW generation at Portland GS.

(4) The need date is based on the 1525MW LMC which assumes that two of the three units are out at Portlands GS and total plant generation is 160MW.

6.2.2 115kV Transmission Facilities

The 115kV facilities in the Metro Toronto Region (see Figure 3-2) can be divided into five main corridors:

1. Manby TS East x Wiltshire TS – Four circuits K1W, K3W, K11, K12W. Forecast loading can exceed corridor rating under certain conditions. More details are provided in Section 7.1.2.
2. Manby TS West x John TS – Four circuits H2JK, K6J, K13J and K14J. These circuits are adequate over the study period.
3. Leaside TS x Hearn TS – Six circuits H6LC, H8LC, H1L, H3L, H7L and H11L. These circuits are expected to be adequate over the study period. .
4. Leaside TS x Cecil TS – Three circuits L4C, L9C, and L12C. These are expected to be adequate over the study period.
5. Leaside TS x Wiltshire TS – Four circuits L13W/L14W/L15/L18W. The L18W circuit is expected to go into service in summer 2016. Loading will exceed corridor rating by 2034 for loss of the L18W circuit. More details are provided in Section 7.10.4.

The loading on the limiting sections is summarized in Table 6-3.

Table 6-3 Overloaded Sections of 115kV circuits

Facilities	2015 MW Load	MW Load Meeting Capability	Limiting Contingency	Need Date
Manby TS x Wiltshire TS 115kV Corridor	330	348/410(1)	K11W	2019-2023(1)
Leaside TS x Wiltshire TS	310	350	L18W	2034

(1) The Manby x Wiltshire corridor provides emergency backup for Dufferin TS load under Leaside area contingencies. Assuming that a 100MW of back up capability is provided, the maximum load that can be supplied in the Fairbanks/Runnymede area is 348MW and the need date for upgrading the corridor is 2019. If 75MW of back up capability is required, the need date will become 2023. However, if back up capability during peak is not considered, maximum load meeting capability is 410MW. The need in this case would be beyond 2035.

6.2.3 Step-Down Transformer Facilities

There are a total of 20 step-down transformers stations in the Central Toronto Sub Region.as follows:

Basin TS	Esplanade TS	Fairbank TS
Bridgman TS	Gerrard TS	Copeland MTS
Carlaw TS	Glengrove TS	John TS
Cecil TS	Main TS	Strachan TS
Charles TS	Terauley TS	Horner TS
Dufferin TS	Wiltshire TS	Manby TS
Duplex TS	Runnymede TS	

The stations non-coincident loads are given in Appendix D Table D-1. The areas and the stations requiring relief are given in Table 6-4.

Table 6-4 Adequacy of Step-Down Transformer Stations - Areas Requiring Relief

Area/Supply	Capacity (MW)	2015 Loading (MW)	Need Date
West Toronto: Fairbanks TS and Runnymede TS	285	291	Now
Southwest Toronto : Manby TS and Horner TS area	400	376	2020-2027 (1)
Downtown Toronto: John TS, Esplanade TS, Terauley TS and Copeland MTS (JETC)	739	632	2020+ (2)

(1) The need dates are based on high and low demand growth rates scenario

(2) The need date will be around 2027 based on the station capacity consideration alone for the Downtown District stations. However, a need date of 2020+ was established by the WG based upon other considerations, such as requirements for spare feeder position. More details are given in Section 7.3.

7. REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES THE ELECTRICAL SUPPLY NEEDS FOR THE METRO TORONTO REGION AND SUMMARIZES THE REGIONAL PLANS FOR ADDRESSING THE NEEDS. THESE NEEDS ARE LISTED IN TABLE 6-1 AND INCLUDE NEEDS PREVIOUSLY IDENTIFIED IN THE IRRP FOR THE CENTRAL TORONTO SUB-REGION [1] AND THE NA FOR THE METRO TORONTO NORTHERN SUB-REGION [2] AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THE CURRENT RIP REPORT.

7.1 West Toronto Area

7.1.1 Station Capacity - Runnymede TS & Fairbank TS

Runnymede TS and Fairbank TS are 115/27.6 kV transformer stations that supply the load demand in the west end of Toronto. The two stations are connected to the 115 kV Manby East transmission system and have been operating at or near their capacity limits for the last five years. THESL has managed growth by transferring loads to adjacent area stations.

The area 2015 extreme weather peak load was 291 MW and exceeded the stations capacity of 285MW. The area is experiencing some re-development and the proposed Eglinton Crosstown Light Railway Transit (“LRT”) project by MetroLinx will add an additional 14 MW of load to Runnymede TS in 2021. Additional step down transformation capacity is required now to provide relief and be able to meet the forecast load demand.

7.1.2 Line Capacity - Manby TS x Wiltshire TS 115kV circuits

The Manby TS x Wiltshire TS four circuit 115kV tower line carries circuits K1W, K3W, K11W and K12W. These circuits supply Fairbanks TS, Runnymede TS and well as Wiltshire TS. Under Leaside area outage conditions, these circuits are also used to pick up all or parts of Dufferin TS and/or Bridgman TS loads. The total corridor capability is dependent on the Fairbanks TS and Runnymede TS load and the load picked up and is given in table below:

Table 7-1 Manby x Wiltshire Corridor Capability

Year	Fairbanks TS, Runnymede TS, and Wiltshire TS Load Forecast (MW)	Amount of Dufferin TS and Bridgman TS Load that can be picked up (MW)	Total Corridor Capability (MW)
2015	330	120	450
2019	349	97	446
2023	375	68	443
2027	390	46	436
2031	399	25	424
2035	406	10	416

The timing of the Manby TS x Wiltshire TS circuits upgrade is dependent on the backup capability desired. If backup capability is not considered, the upgrade can be deferred to beyond 2035. However, if at least 70MW of back up capability - equal to about half of Dufferin TS load - is deemed appropriate, the upgrade would be deferred to about 2023.

Figure 7-1 West Toronto Area - Fairbank TS and Runnymede TS

7.1.3 Recommended Plan and Current Status

The Working Group has considered and reviewed several options to provide additional transformation capacity in West Toronto area as part of the Central Toronto IRRP. Based upon the review, and consistent with the IRRP Working Group recommendation is to expand Runnymede TS by adding two 115/27.6 kV 50/83 MVA transformers and a 27.6kV switchyard with six feeders. This work is required to be completed as early as possible.

The Working Group also recommends that the Manby TS to Wiltshire TS tower line carrying circuits K1W/K3W/K11W/K12W be also upgraded at the same time. This option would maintain the load transfer capability between Leaside TS and the Manby TS under emergency or outage conditions in addition to supplying future load growth in the West Toronto Area.

The estimated total cost of the work is approximately $90 M, which includes $34 M for the station work at Runnymede TS, $16 M for the upgrade of four 9.5 km long circuits between Manby TS and Wiltshire TS and $40 M for distribution facilities by THESL. The transmission cost of $50M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals. The estimate is expected to be completed by the end of Q2 2016. It will also confirm if the targeted in-service date of May 2019 for this project is achievable. A Section 92 application will be submitted in 2016.

7.2 Southwest Toronto Area

7.2.1 Station Capacity – Southwest Toronto (Manby TS & Horner TS)

Manby TS and Horner TS are two 230/27.6 kV transformer stations supplying the load demand in the southwest end of Toronto (see Figure 7-2). Based on the current RIP forecast the 400MW combined station capacity of the stations is forecast to be exceeded by summer 2020. Additional step down transformation is required to provide relief.

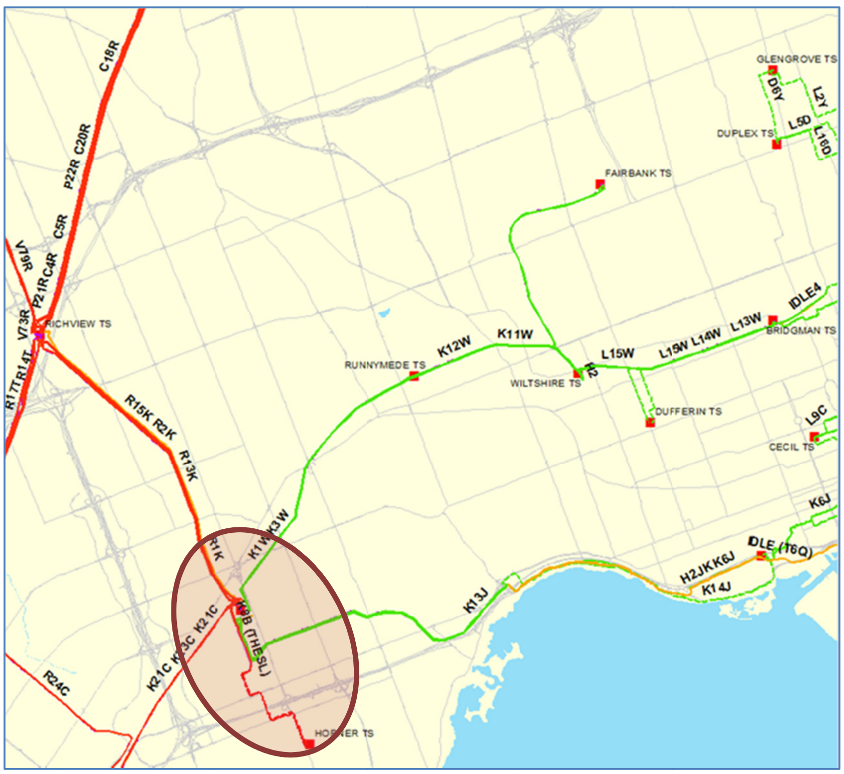

Figure 7-2 Horner TS and Manby TS Supply Area

7.2.2 Recommended Plan and Current Status.

To address the need for additional step down transformation capacity in the Southwest Toronto area, the Working Group's recommended building a second 230/27.6 kV DESN at the existing Horner TS site. Two 75/125MVA transformers will be installed at the station along with a new 27.6kV switchyard. Load transfer out of Manby TS to Horner TS is required to relieve Manby TS as the loading at that station exceeds its capacity. New distribution feeder ties are required to be built between Manby TS and Horner TS by THESL.

The estimated total cost of the work is about $53M, which includes $34 M for the station work at Horner TS and $19M for THESL distribution facilities. The transmission cost of $34M is expected to be recovered in accordance with the TSC.

Hydro One has initiated development work on the project covering preparation of estimates and obtaining of EA approvals at the request of THESL. The current in-service date for the project is expected to be May 2020.

7.3 Downtown District

7.3.1 Station Capacity – JETC[2] Area

The Toronto Downtown Core area is mainly supplied by the three existing 115/13.8 kV stations: John TS, Esplanade TS, and Terauley TS. John TS is connected to the Manby West system while Esplanade TS and Terauley TS are fed from the 115 kV Leaside / Hearn system. (see Figure 7-3)

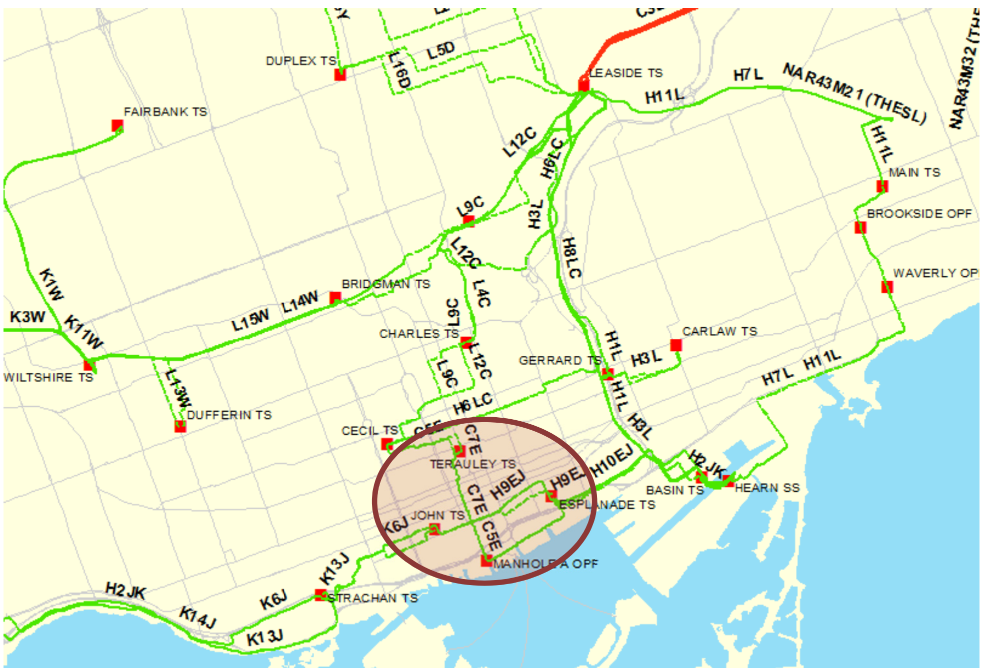

Figure 7-3 Toronto Downtown Supply Area

John TS was built in the 1950's and the THESL switchgear at the station is approaching end of life. THESL is building a new 115/13.8kV owned transformer station, Copeland MTS in the Downtown

[2] JETC denotes John TS, Esplanade TS, Terauley TS, and Copeland MTS which jointly supply the Downtown District.

District near John TS with normal supplied from the 115 kV Manby West system. The station first phase capacity will be around 130 MVA and it is expected to be in service in 2016. Copeland MTS will provide a new source of supply to the area customers and facilitate the replacement of end of life switchgear at John TS.

With the new Copeland MTS in-service in 2016, adequate transformation capacity will be available in the Downtown District till 2027. However, most of this capacity will be at John TS as 13.8kV buses at both Terauley TS and Esplanade TS are at or approaching capacity limits. THESL anticipates that the need for new transformation facility is more advanced due to limited spare feeder positions available at John TS for new customer connection and load transfer required to facilitate the refurbishment work at John TS. At the current pace of development in these areas, both bus and feeder position in the Downtown Core area are expected to be at or near capacity within five to ten years[3]. Specific issues identified by THESL Hydro are as follows:

- By 2019 THESL forecasts that two busses will be overloaded (ie. loaded beyond 10 Day LTR) at George and Duke MS and two busses overloaded at John/Windsor TS.
- By 2025 THESL forecasts that one bus will be overloaded at Copeland TS, two busses overloaded at George and Duke MS and three busses overloaded at John/Windsor TS.
- At John/Windsor TS, four out of six busses have no spare feeder positions to connect new customers. One bus has a single spare feeder position and one bus has two spare feeder positions.
- At George and Duke MS, one bus has no spare feeder positions and one bus has six spare feeder positions.
- At Esplanade TS, there is only one bus with three spare feeder positions.
- Once in service, Copeland TS is forecasted to have six and three spare positions on each its two busses, respectively.

7.3.2 Recommended Plan and Current Status

Based on the current information, the need to relieve the stations in Downtown District is expected to be beyond 2020. However, the need date may get delayed or brought forward if the load growth in this area is slower or faster than currently anticipated. The Working Group recommends that this need and timing should be further refined by THESL through their distribution planning process and included in updates to the IRRP and RIP. The uptake of CDM and DG should be preserved and re-assessed.

In the case where CDM and DG are deemed insufficient, building Copeland Phase 2 and installing additional transformers and two new buses at Copeland MTS site is the most cost effective way to meet the required THESL needs. The site and the high voltage switching facilities required to accommodate this expansion (Copeland Phase 2) are already included as part of the Copeland MTS Phase 1 project.Copeland MTS is an underground station and is not located adjacent to residential land uses. The THESL estimated cost for Copeland MTS Phase 2 to be approximately $46 M.

[3] Further information may be found in THESL's rate application EB-2014-0116 to the Ontario Energy Board

7.4 Transmission Line Capacity – 230 kV Richview TS to Manby TS Corridor

7.4.1 Description

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto Sub-Region. It also supplies the load in the southern Mississauga and Oakville areas via Manby TS. Along this Corridor there are two double circuit 230kV lines R1K/R2K and R13K/R15K. In addition the corridor contains an idle double circuit 115kV line. Figure 7-4 shows the area supplied by Richview TS x Manby TS circuits.

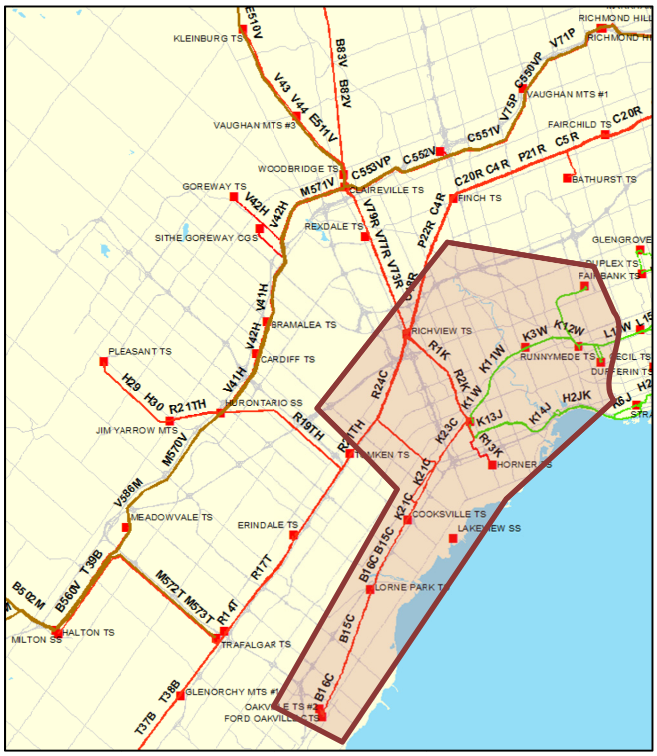

Figure 7-4 Richview x Manby Supply Area Map

The forecast loading on the Richview TS to Manby TS circuits is given in Table 7-2 below for both the high growth and low growth scenarios. The loads include the 115 kV Manby East, 115 kV Manby West, 230 kV Manby, and 230 kV Oakville-Cooksville loads. The need date for providing relief is 2020 for the high growth scenario and 2023 for the low growth scenario.

Table 7-2 also shows the effect of Metrolinx Mimico TPS on the need date for relief. In both scenarios, relief is required by 2020. The magnitude of Metrolinx load is large enough to trigger the reinforcement.

Again, due to the large incremental load from Mimico TPS, CDM will not be sufficient to help eliminate or even defer the need date for the transmission reinforcement. Transmission reinforcement is required to be implemented before the Mimico TPS can be connected.

Table 7-2 Coincident RIP MW Load Forecast for Richview TS x Manby TS Area

	Limit	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035
Base - Without Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1580**	1617	1646	1674	1698	1722	1742	1763
Low Growth	1540	1456	1481	1503	1530	**1544**	1557	1566	1572	1577	1597	1617
With Metrolinx Mimico TPS load												
High Growth	1540	1456	1488	1536	**1640**	1697	1726	1754	1778	1802	1822	1843
Low Growth	1540	1456	1481	1503	**1590**	1624	1637	1646	1652	1657	1677	1697

7.4.2 Alternatives Considered

The following alternatives are currently under consideration:

<u>Upgrade four existing 230kV Richview TS x Manby TS circuits:</u> Re-conductor with higher-capacity conductors on existing towers. Hydro One will check the feasibility of this option without major tower modifications and also in terms of outages arrangement. The estimated total cost of this option is about $16M, assuming that no major tower modifications and no bypass lines during re-conductoring are required.

<u>Rebuild existing 115kV Richview TS x Manby TS line:</u> Rebuild the existing idle 115 kV double-circuit line as a 230kV double-circuit line. The new 230 kV line is to share the existing terminations for circuits R2K and R15K at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits, effectively doubling the ampacity of R2K and R15K. This alternative requires the replacement of all the existing 115 kV towers with 230 kV towers. The estimated total cost of this option is about $19.5M.

<u>Build two new 230 kV Richview TS x Manby TS circuits:</u> Similar to the second alternative above, rebuild the two existing idle 115 kV double-circuit line as a 230kV double-circuit line. New terminations for these circuits are required at Richview TS and Manby TS. The ampacity of the new conductors are to be equal to or better than that of the existing circuits. This alternative not only provides higher transmission capacity but also increases the supply reliability to the Central Downtown and Southwest GTA area. The estimated total cost of this option is around $39.5M due to the extra station work required at the Richview TS and Manby TS.

<u>Extend the Cooksville TS x Oakville TS line to Trafalgar TS:</u> Extend the Cooksville TS x Oakville TS 230kV double circuit line B15C/B16C about 8km to Trafalgar TS where new 230kV switching facilties are also required. This alternative increases supply capacity and reliability to Southwest GTA area from Trafalgar TS, and thus alleviates the loading on the Richview x Manby corridor. The total estimated cost of this line and station work is around $54M.

CDM & DG: According to Central Toronto IRRP report, the potential DG development, targeted demand response and the potential incremental demand response in these areas supplied by Manby TS may defer the need for this transmission reinforcement by several years, depending on the load growth rate. However, with Mimico TPS connected near Horner TS, these targeted and potential incremental demand response will not be adequate due to the size of the extra load added by the TPS.

The Maintain Status Quo or Do Nothing alternative was not considered as it does not provide relief for the Richview x Manby transmission lines.

7.4.3 Recommended Plan and Current Status

The Metrolinx Mimico TPS information is new and was provided as part of the RIP after the IRRP was completed in April 2015. If this TPS is going to be in-service as planned in 2020, CDM initiatives will not effectively defer the need date for this transmission corridor because of the size of the additional load. Therefore, upgrading the existing Richview x Manby corridor or new supply path for the areas served by Manby TS will be required before the Metrolinx Mimico TPS can be connected.

The Trafalgar x Oakville line alternative, at $54M, is the highest cost alternative ($14.5M higher than the next most expensive alternative) and there is a risk that it may not be able to be completed in time to connect the the Metrolinx Mimico TPS in 2020. This alternative may also trigger the need for additional transformation facilities and thus would incur additional costs.

As a result, Working Group recommends that Hydro One proceed with the development and estimate work on the first three alternatives listed in Section 7.4.2 in 2016. Both EA and Section 92 approvals will be required and it is expected to take at least 3-4 years for the implementation of a wire solution. The Working Group will select the preferred alternative by December 2016. Hydro One will then plan to initiate project execution by summer 2018 in order to enable the connection of MetroLinx Mimico TPS by summer 2020.

7.5 Transmission Line Capacity – Circuit C10A (Duffin Jct. to Agincourt Jct)

C10A is a 20 km long radial circuit in Metro Toronto Northern Sub-Region from Cherrywood TS supplying Agincourt TS and Cavanagh MTS. The Metro Toronto Northern Sub-Region NA identified that the capacity of this circuit was thermally limited by a section approximately 4 km long between Duffin Jct. and Agincourt Jct. The flow on this section of the circuit might exceed its long-term emergency (LTE) rating under summer peak load conditions following certain contingencies.

A preliminary study based on the old field survey data was done in July 2015. The old record showed that the LTE rating was limited by some underbuilds along the line section. A new field survey was then carried out in October 2015. It was discovered that the aforementioned underbuilds had been previously removed, and the LTE rating of this line section should be 840A. The record is being updated. No further action is required.

7.6 Breaker Failure at Manby TS

7.6.1 Description

The failure of any of the Manby TS breakers A1H4 and H1H4 in the Manby West 230kV yard and the breaker H2H3 in the Manby east 230kV yard can cause the outage of any two of the three 230/115kV autotransformers at either the west or east yard of Manby TS. This may result in the overload of the remaining autotransformer. Based on the Coincident RIP Forecast the need date for the work is summer 2018 and summer 2021 for Manby West and Manby East respectively.

7.6.2 Recommended Plan and Current Status

The Working Group has recommended that installation of a Special Protection Scheme (SPS) is the most cost effective means to mitigate the breaker failure risk.

Hydro One is working on the development and estimate work for the SPS at Manby TS. The preliminary estimate for this work is approximately $2M and this will be updated when the development work is complete by summer 2016. The planned in-service of this work is summer 2018.

7.7 Breaker Failure at Leaside TS

The failure of breaker L14L15 at Leaside TS can cause the outage of two of the Leaside TS to Bridgman TS circuits. This may result in the loss of Transformers T11, T12, T14 and T15 at Bridgman TS. Under this scenario, two of the four LV buses will be lost by configuration. Only transformer T13 remains in service and supplies buses HLA1 and HLA7.

The 15 minute LTR for the X and Y windings of Transformer T13 is 55MVA. Therefore, as long as the loading on the HLA1 and HLA7 does not exceed the 15 minutes LTR, the operator can take action to reduce load to within transformer LTE ratings.

A new normally open switch is being installed at Bridgman TS as part of the Leaside-Bridgman Transmission Reinforcement project. This new switch can be closed remotely following the loss of the circuit L15W to resupply the two Bridgman transformers from the circuit L13W. This will alleviate the loading of the transformer T13 and the circuit L18W. and any possible voltage issue at Bridgman TS. Therefore, no investment is recommended.

7.8 Cherrywood to Leaside (CxL) Double Circuit Contingencies

Double circuit contingencies involving the lines C2L/C3L or C16L/C17L from Cherrywood TS to Leaside TS (CxL) can result in the loss of two of the three 230/115kV autotransformers on the same half of Leaside TS. The long-term emergency rating of the remaining autotransformer may be exceeded if only a single combustion unit at the Portland Energy Centre (PEC) is available, coincident with either of the abovementioned double contingencies during peak load condition.

The Working Group recommends that no further work is required in the near- and mid-term as there is already an existing operating instruction in place to cover the overload issue of the remaining Leaside autotransformer by closing the 115kV bus-tie at Leaside TS.

7.9 Load Restoration – Northern Sub-Region (Bathurst TS, Fairchild TS, Leslie TS)

Bathurst TS, Fairchild TS, and Leslie TS are supplied by the 230 kV Richview x Cherrywood x Parkway system in the Metro Toronto Northern Sub-Region. Following two circuit contingencies, approximately 240-300 MW of load during summer peak time could be lost during each contingency scenario, as follows:

Table 7-3 Maximum Load Loss during Two Circuit Contingencies

Double Element Contingency	Station Connected	Non-Coincident Load Forecast (MW)	
		2015	2025
P22R + C18R	Bathurst TS	271	279
C18R + C20R	Fairchild TS	292	301
P21R + C5R	Leslie TS	239	249

There are currently no existing transmission switching facilities to allow load restoration immediately. Partial load could be restored via distribution transfer to the nearby stations.

For Bathurst and Leslie cases, the stations are supplied by circuits on separate transmission lines for all or most sections. The probability of occurrence of overlapping outages on circuits on different tower lines is extremely low. The supplied circuits for Fairchild TS are on common tower for two-third of the line (approximately 32km).

Based on the outage records in the past 25 years there has been no incidence of any double contingencies described above.

A single transformer station would require four motorized disconnect switches to be useful. Typical cost for installing these transmission switching facilities per station would be between $8-10M.

Based on the low probability of frequency of such events versus the high mitigation cost, the Working Group recommendation is that no further action is required.

7.10 Long Term Needs

Four longer term needs had been identified in the Central Toronto IRRP as follows:

- Transmission Line Capacity – 115 kV Manby West To Riverside Junction
- Transformation Capacity – 230/115 kV Manby TS
- Transformation Capacity – 230/115 kV Leaside TS
- Leaside TS x Wiltshire TS 115kV circuits

Loading on Manby TS and the Manby TS x Riverside Junction circuit are within ratings over the study period under the Coincident RIP forecast. The Working Group recommendation is that no further action is required.

The Leaside TS transformer and the Leaside TS x Wiltshire circuits will require relief in the long term. This issue will be considered in the next planning cycle. The Working Group recommendation is that no further action is required. However, Hydro One and IESO will continue to monitor loads and initiate necessary relief measures, if required.

8. CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE METRO TORONTO REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in the Table 8-1 below.

Table 8-1 Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Supply Security – Breaker Failure at Manby West & East TS
II	West Toronto Area - Station Capacity and Line Capacity
III	Southwest Toronto - Station Capacity
IV	Downtown District - Station Capacity
V	230 kV Richview x Manby Corridor– Line Capacity
VI	Leaside Autotransformers
VII	Line Capacity – 115 kV Leaside x Wiltshire Corridor

Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the near-term and mid-term needs are summarized in the Table 8-2 below. Investments to address the long-term needs where there is time to make a decision (Need No. VI & VII), will be reviewed and finalized in the next regional planning cycle.

Table 8-2 Regional Plans – Next Steps, Lead Responsibility and Plan In-Service Dates

Id	Project	Next Steps	Lead Responsibility	I/S Date	Est. Cost	Needs Mitigated
1	Manby SPS	Transmitter to carry out the work	Hydro One	2018	$2M	I
2	Runnymede Expansion & 115 kV Manby x Wiltshire Corridor Upgrade	Transmitter to carry out the work	Hydro One	2019	$90M	II
3	Horner Expansion	Transmitter to carry out the work	Hydro One	2020	$53M	III
4	230 kV Richview x Manby Corridor Upgrade	Transmitter to carry out the work	Hydro One	2020	$20-40M	V
5	Copeland Phase 2	LDC to carry out work & monitor growth	THESL	2020+	$46M	IV

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered every five years. The next planning cycle for the Metro Toronto Region is expected to be started in 2018. However, the Region will continue to be monitored and should there be a need that emerges due to a change in load forecast or any other reason, the regional planning cycle will be started earlier to address the need.

9. REFERENCES

[1]. Independent Electricity System Operator, "Central Toronto Integrated Regional Resource Plan", 28 April 2015.
http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/2015-Central-Toronto-IRRP-Report.pdf

[2]. Hydro One, "Needs Screening Report, Metro Toronto Region – Northern Sub-Region", 11 June 2014.
http://www.hydroone.com/RegionalPlanning/Toronto/Documents/Needs%20Assessment%20Report%20-%20Metro%20Toronto%20-%20Northern%20Subregion.pdf

Appendix A. Stations in the Metro Toronto Region

Station (DESN)	Voltage (kV)	Supply Circuits
Agincourt TS T5/T6	230/27.6	C4R/C10A
Basin TS T3/T5	115/13.8	H3L/H1L
Bathurst TS T1/T2	230/27.6	P22R/C18R
Bathurst TS T3/T4	230/27.6	P22R/C18R
Bermondsey TS T1/T2	230/27.6	C17L/C14L
Bermondsey TS T3/T4	230/27.6	C17L/C14L
Bridgman TS T11/T12/T13/T14/T15	115/13.8	L13W/L15W/L14W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cecil TS T1/T2	115/13.8	Cecil Buses H & P
Cecil TS T3/T4	115/13.8	Cecil Buses P & H
Charles TS T1/T2	115/13.8	L4C/L9C
Charles TS T3/T4	115/13.8	L12C/L4C
Dufferin TS T1/T3	115/13.8	L13W/L15W
Dufferin TS T2/T4	115/13.8	L13W/L15W
Duplex TS T1/T2	115/13.8	L16D/L5D
Duplex TS T3/T4	115/13.8	L5D/L16D
Ellesmere TS T3/T4	230/27.6	C2L/C3L
Esplanade TS T11/T12/T13	115/13.8	H2JK/H10EJ(C5E)/H9EJ(C7E)
Fairbank TS T1/T3	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W
Fairchild TS T1/T2	230/27.6	C18R/C20R

Station (DESN)	Voltage (kV)	Supply Circuits
Fairchild TS T3/T4	230/27.6	C18R/C20R
Finch TS T1/T2	230/27.6	C20R/P22R
Finch TS T3/T4	230/27.6	P21R/C4R
Gerrard TS T1/T3/T4	115/13.8	H3L/H1L
Glengrove TS T1/T3	115/13.8	D6Y/L2Y
Glengrove TS T2/T4	115/13.8	D6Y/L2Y
Horner TS T3/T4	230/27.6	R13K/R2K
John TS T1/T2/T3/T4	115/13.8	John Buses K1 & K2 & K3 & K4
John TS T5/T6	115/13.8	John Buses K1 & K4
Leaside TS T19/T20/T21 13.8	230/13.8	C2L/C3L/C16L
Leaside TS T19/T20/T21 27.6	230/27.6	C2L/C3L/C16L
Leslie TS T1/T2 13.8	230/13.8	P21R/C5R
Leslie TS T1/T2 27.6	230/27.6	P21R/C5R
Leslie TS T3/T4	230/27.6	P21R/C5R
Main TS T3/T4	115/13.8	H7L/H11L
Malvern TS T3/T4	230/27.6	C4R/C5R
Manby TS T13/T14	230/27.6	Manby W Buses A1 & H1
Manby TS T3/T4	230/27.6	Manby W Buses A1 & H1
Manby TS T5/T6	230/27.6	Manby E Buses H2 & A2
Rexdale TS T1/T2	230/27.6	V74R/V76R
Richview TS T1/T2	230/27.6	Richview Buses H1 & A1
Richview TS T5/T6	230/27.6	V74R/V72R
Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
Runnymede TS T3/T4	115/27.6	K12W/K11W

Station (DESN)	Voltage (kV)	Supply Circuits
Scarboro TS T21/T22	230/27.6	C14L/C2L
Scarboro TS T23/T24	230/27.6	C15L/C3L
Sheppard TS T1/T2	230/27.6	C16L/C15L
Sheppard TS T3/T4	230/27.6	C15L/C16L
Strachan TS T12/T14	115/13.8	H2JK/K6J
Strachan TS T13/T15	115/13.8	K6J/H2JK
Terauley TS T1/T4	115/13.8	C7E/C5E
Terauley TS T2/T3	115/13.8	C7E/C5E
Warden TS T3/T4	230/27.6	C14L/C17L
Wiltshire TS T1/T6	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T2/T5	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T3/T4	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Cavanagh MTS T1/T2	230/27.6	C20R/C10A
IBM Markham CTS T1/T2	230/13.8	P21R/P22R
Markham MTS #1 T1/T2	230/27.6	P21R/P22R
Copeland MTS T1/T3 (Future)	115/13.8	D11J/D12J

Appendix B. Transmission Lines in the Metro Toronto Region

Location	Circuit Designations	Voltage (kV)
Richview x Manby	R1K, R2K, R13K, R15K	230
Richview x Cooksville	R24C	230
Manby x Cooksville	K21C, K23C	230
Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
Cherrywood x Richview	C4R, C5R, C18R, C20R	230
Cherrywood x Agincourt	C10A	230
Parkway x Richview	P21R, P22R	230
Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
Manby West x John	K6J, K13J, K14J	115
Manby West x John x Hearn	H2JK	115
John x Esplanade x Hearn	H9EJ, H10EJ	115
Esplanade x Cecil	C5E, C7E	115
Hearn x Cecil x Leaside	H6LC, H8LC	115
Hearn x Leaside	H1L, H3L, H7L, H11L	115
Leaside x Charles	L4C	115
Leaside x Cecil	L9C, L12C	115
Leaside x Duplex	L5D, L16D	115
Leaside x Glengrove	L2Y	115
Duplex x Glengrove	D6Y	115

Appendix C. Distributors in the Metro Toronto Region

Distributor Name	Station Name	Connection Type
Toronto Hydro-Electric System Limited	Agincourt TS	Tx
	Basin TS	Tx
	Bathurst TS	Tx
	Bermondsey TS	Tx
	Bridgman TS	Tx
	Carlaw TS	Tx
	Cecil TS	Tx
	Charles TS	Tx
	Dufferin TS	Tx
	Duplex TS	Tx
	Ellesmere TS	Tx
	Esplanade TS	Tx
	Fairbank TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Gerrard TS	Tx
	Glengrove TS	Tx
	Horner TS	Tx
	John TS	Tx
	Leaside TS	Tx
	Leslie TS	Tx
	Main TS	Tx
	Malvern TS	Tx
	Manby TS	Tx
	Rexdale TS	Tx
	Richview TS	Tx
	Runnymede TS	Tx
	Scarboro TS	Tx
	Sheppard TS	Tx
	Strachan TS	Tx
	Terauley TS	Tx
	Warden TS	Tx
	Wiltshire TS	Tx
	Cavanagh MTS	Tx
	Copeland MTS (Future)	Tx

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc. (Dx)	Agincourt TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Leslie TS	Tx
	Malvern TS	Tx
	Richview TS	Tx
	Sheppard TS	Tx
	Warden TS	Tx
PowerStream Inc.	Agincourt TS	Dx
	Fairchild TS	Dx
	Finch TS	Dx
	Leslie TS	Dx
Veridian Connections Inc.	Malvern TS	Dx
	Sheppard TS	Dx
Enersource Hydro Mississauga Inc.	Richview TS	Dx

Appendix D. Metro Toronto Regional Load Forecast (2015-2035)

Table D-1 Non-Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	**Lea115**	**Basin**	84	57	60	64	67	68	69	70	71	73	75	77	79	81	83
		Bridgman	179	174	177	179	181	182	183	184	185	187	189	191	193	195	198
		Carlaw	131	65	66	68	70	71	73	74	72	71	72	75	78	80	82
		Cecil	204	168	169	171	173	175	177	178	181	183	186	190	193	196	199
		Charles	200	151	153	156	158	159	161	162	165	167	170	172	173	177	181
		Dufferin	161	141	144	147	149	150	150	150	152	154	156	158	159	161	163
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	196	201	206	210	215
		Gerrard	62	44	45	46	48	49	50	51	63	78	88	90	92	93	94
		Glengrove	84	55	57	58	59	60	60	61	62	63	64	66	67	68	69
		Main	72	65	64	63	62	63	64	66	65	65	66	69	72	75	77
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	**Wiltshire**	113	67	68	69	70	70	71	72	72	72	72	73	74	75	76
	ManbyE115-27.6	**Runnymede**	109	116	118	120	122	122	123	123	125	126	128	129	131	132	133
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	175	178	181	184	186	187	188	190	193	195	197	199	201	203
	ManbyW115	**Copeland**	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	276	276	189	189	192	195	198	202	206	209	213	218	221	225
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2143	2175	2206	2255	2279	2303	2341	2390	2444	2495	2540	2587	2626	2666
Eastern 230kV	**CxL230**	**Bermondsey**	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	169	171	173	175	175	175	175	176	177	178	180	181	182	183
		Leaside	210	156	158	159	161	161	161	161	163	165	166	168	170	172	174
		Scarboro	340	222	225	227	230	230	230	230	231	233	234	236	238	239	241
		Sheppard	204	170	170	171	171	171	171	171	173	174	175	176	178	179	180
		Warden	183	126	128	129	130	130	130	130	131	132	133	134	135	136	137
	Metrolinx	**Metrolinx - Warden**	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1037	1047	1057	1067	1067	1107	1127	1155	1164	1172	1180	1189	1197	1206
Northern 230kV	**CxR**	**Agincourt**	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	271	272	274	275	275	275	275	277	279	281	283	285	287	289
		Cavanagh	157	141	141	141	142	142	142	142	143	144	145	146	147	148	149
		Fairchild	357	292	293	295	297	297	297	297	299	301	303	306	308	310	312
		Finch	363	289	292	295	298	298	298	298	300	302	304	306	309	311	313
		Leslie	325	239	241	244	246	246	246	246	248	249	251	253	255	256	258
		Malvern	176	106	106	107	107	107	107	107	108	109	109	110	111	112	113
Northern 230kV Total			1885	1433	1444	1455	1466	1467	1468	1469	1479	1490	1500	1511	1521	1532	1543
Western 230kV	**Manby230**	**Horner**	179	144	146	148	150	151	152	153	155	157	157	156	155	157	159
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	**Metrolinx - Cityview**	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	**Rexdale**	187	135	135	135	135	134	133	132	133	134	135	136	137	138	139
		Richview T1T2EZ	154	130	131	131	131	130	129	128	129	130	131	132	133	134	135
		Richview T5T6JQ	188	109	110	110	110	109	108	108	108	109	110	111	111	112	113
		Richview T7T8BY	113	54	54	54	54	54	54	53	54	54	54	55	55	56	56
Western 230kV Total			1042	805	811	818	825	825	905	945	994	1003	1013	1023	1034	1043	1052
Grand Total			6995	5419	5477	5537	5613	5638	5783	5883	6019	6100	6180	6254	6331	6398	6466

Table D-2 Coincident RIP Forecast (High Demand Growth)

			LTR	2015	2016	2017	2018	2019	2020	2021	2023	2025	2027	2029	2031	2033	2035
Central 115kV	Lea115	Basin	84	52	55	58	61	62	63	63	65	66	68	70	72	73	75
		Bridgman	179	171	173	175	177	179	180	181	182	183	185	187	189	192	194
		Carlaw	131	61	63	65	67	68	69	70	69	68	68	71	74	76	78
		Cecil	204	152	154	156	158	159	161	162	165	167	170	173	176	178	181
		Charles	200	150	152	155	157	159	160	161	164	166	169	171	172	176	180
		Dufferin	161	139	142	144	147	147	148	148	150	152	153	155	157	159	160
		Duplex	121	103	105	107	109	110	111	112	114	116	118	121	123	125	127
		Esplanade	177	169	170	172	173	176	178	180	185	190	195	200	206	210	215
		Gerrard	62	44	45	46	47	48	49	50	62	77	87	89	91	92	93
		Glengrove	84	52	53	55	56	57	57	58	59	60	61	62	64	64	65
		Main	72	59	59	58	57	58	59	60	60	60	61	64	67	69	71
		Terauley	205	187	191	196	201	205	209	213	217	220	224	230	236	240	245
	ManbyE115-13.8	Wiltshire	113	61	61	62	63	64	64	65	65	65	65	66	67	68	69
	ManbyE115-27.6	Runnymede	109	96	98	99	101	101	102	102	103	105	106	107	109	110	110
		Runnymede -LRT	0	0	0	0	0	0	0	14	18	23	26	26	26	26	26
		Fairbank	176	174	177	179	183	184	185	186	188	191	193	195	197	199	201
	ManbyW115	Copeland	111	0	0	86	102	102	102	102	106	111	113	113	113	113	113
		John	246	267	266	179	179	182	185	188	191	195	199	202	206	210	213
		Strachan	161	130	133	135	138	139	141	143	145	146	149	152	154	156	157
Central 115kV Total			2595	2067	2097	2128	2176	2198	2222	2259	2307	2359	2409	2453	2498	2536	2575
Eastern 230kV	CxL230	Bermondsey	348	194	196	198	200	200	200	200	202	203	204	206	207	209	210
		Ellesmere	189	154	155	157	159	159	159	159	160	161	162	163	164	166	167
		Leaside	210	154	156	158	159	159	159	159	161	163	165	167	168	170	172
		Scarboro	340	220	222	225	227	227	227	227	229	230	232	234	235	237	239
		Sheppard	204	164	164	165	165	165	165	165	166	168	169	170	171	172	174
		Warden	183	125	126	127	129	129	129	129	130	130	131	132	133	134	135
	Metrolinx	Metrolinx - Warden	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
Eastern 230kV Total			1474	1010	1020	1030	1040	1040	1080	1100	1128	1136	1144	1152	1160	1168	1176
Northern 230kV	CxR	Agincourt	174	95	97	99	101	102	103	104	104	105	106	107	107	108	109
		Bathurst	334	245	247	248	249	249	249	249	251	253	255	257	258	260	262
		Cavanagh	157	119	119	119	120	120	120	120	120	121	122	123	124	125	126
		Fairchild	357	256	257	259	260	260	260	260	262	264	266	268	270	272	273
		Finch	363	273	276	278	281	281	281	281	283	285	287	289	291	293	295
		Leslie	325	223	225	227	229	229	229	229	231	233	234	236	238	239	241
		Malvern	176	106	106	106	107	107	107	107	108	108	109	110	111	111	112
Northern 230kV Total			1885	1317	1327	1337	1347	1348	1349	1351	1360	1370	1379	1389	1399	1408	1418
Western 230kV	Manby230	Horner	179	129	131	133	135	136	137	138	140	141	142	141	139	141	143
		Manby	221	232	236	240	244	246	249	251	255	259	265	273	282	286	290
	Metrolinx	Metrolinx - Cityview	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
		Metrolinx - Mimico	0	0	0	0	0	0	40	60	80	80	80	80	80	80	80
	Rich230	Rexdale	187	133	133	133	133	132	131	130	131	132	133	134	135	136	137
		Richview T1T2EZ	154	128	128	129	129	128	127	126	127	128	129	130	131	131	132
		Richview T5T6JQ	188	107	107	108	108	107	106	106	106	107	108	109	109	110	111
		Richview T7T8BY	113	52	52	52	52	52	51	51	51	52	52	53	53	53	54
Western 230kV Total			1042	782	788	794	801	801	881	921	970	979	988	998	1009	1018	1027
Grand Total			6995	5176	5232	5289	5363	5388	5532	5631	5765	5843	5920	5992	6066	6131	6196

Appendix E. List of Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

GTA North

Regional Infrastructure Plan

February 5, 2016

hydro one

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Enersource Hydro Mississauga Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Newmarket-Tay Power Distribution Ltd.
PowerStream Inc.
Toronto Hydro Electric System Ltd.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN (“RIP”) WAS PREPARED BY HYDRO ONE NETWORKS INC. (“HYDRO ONE”) AND THE WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE (“TSC”) REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN FACILITIES THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS OF THE GTA NORTH REGION.

The participants of the RIP Working Group included members from the following organizations:

- Enersource Hydro Mississauga Inc.
- Hydro One Brampton Networks Inc.
- Hydro One Networks Inc. (Distribution)Independent Electricity System Operator
- Newmarket-Tay Power Distribution Ltd.
- PowerStream Inc.
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the OEB’s mandated regional planning process for the GTA North Region which consists of the York Sub-Region and the Western Sub-Region. It follows the completion of the York Sub-Region’s Integrated Regional Resource Planning (“IRRP”) by the IESO in April 2015 and the Western Sub-Region’s Needs Assessment (“NA”) Study by Hydro One in June 2014.

This RIP provides a consolidated summary of needs and recommended plans for the York Sub-Region over the near-term (up to 5 years) and the mid-term (5 to 10 years). The York Region IRRP has identified the need for additional transformation capacity in Markham, Northern York Region and Vaughan in the mid-term. These mid-term needs are linked to long-term (beyond 10 years) transmission capacity needs.

No needs have been identified over the near-term and mid-term for the Western Sub-Region except for load restoration for the loss of double circuit 230 kV line V43/V44. It is recommended that this need be assessed as part of the IESO led GTA West bulk system planning initiative and as a result is not addressed in this RIP.

The major infrastructure investments planned for the GTA North Region over the near-term, identified in the various phases of the regional planning process, are given in the Table below.

No.	Project	I/S date	Cost
1	Vaughan #4 MTS	Q1 2017	$25M*
2	Holland breakers, disconnect switches and special protection scheme	Q4 2017	$32M
3	Parkway belt switches	Q4 2018	$4-6M

* PowerStream’s station cost. Hydro One line connection cost is currently being estimated

The planning is continuing for the mid-term and long-term needs. These needs, and the options to address these them, are being reviewed by the Working Group as part of the community engagement activities currently being led by the IESO and LDCs through the Local Advisory Committee process. The Working Group expects to finalize recommendations to address these and associated long-term transmission needs in an IRRP update currently scheduled for 2017.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA NORTH REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Enersource Hydro Mississauga Inc. ("Enersource"), Hydro One Brampton Networks Inc. ("Hydro One Brampton"), Hydro One Distribution, Newmarket-Tay Power Distribution Ltd. ("NTPDL"), PowerStream Inc. ("PowerStream"), Toronto Hydro-Electric System Limited ("THESL"), and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA North Region includes most of the Regional Municipality of York and parts of the City of Toronto, Brampton, and Mississauga (see Figure 1-1). Electrical supply to the Region is provided through 230 kV transmission circuits, fifteen step-down transformer stations ("TS"), and the York Energy Centre ("YEC") generating station ("GS").

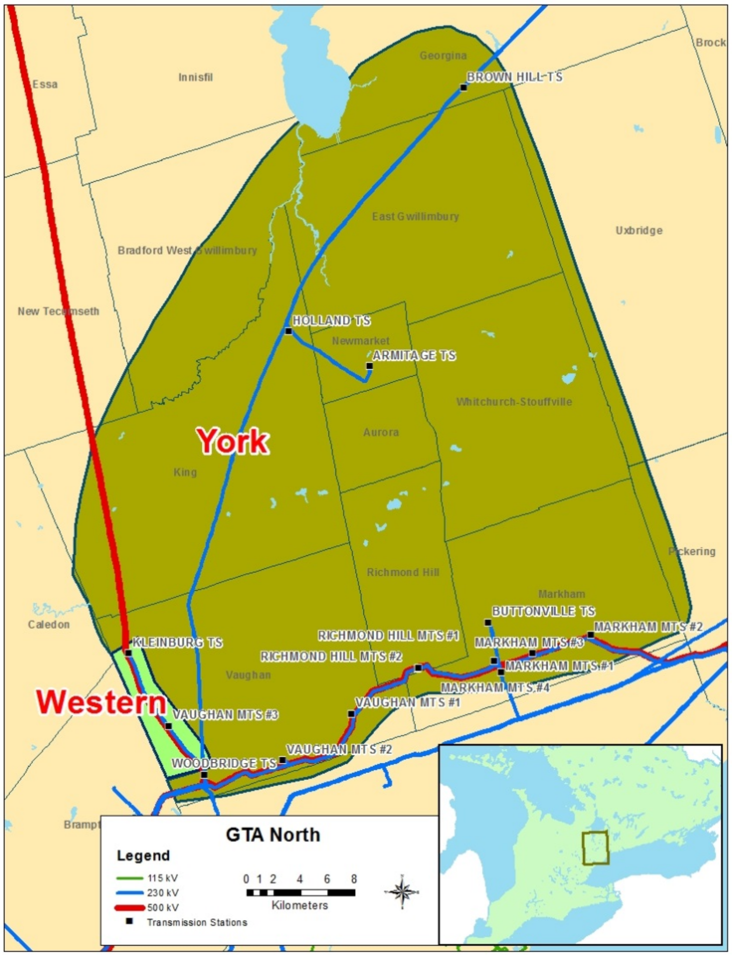


Figure 1-1 GTA North Region

1.1 Scope and Objectives

This RIP report examines the needs in the GTA North Region. Its objectives are to:

- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop a wires plan to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near and mid-term needs (2015 to 2025) identified in previous planning phases (Needs Assessment and Integrated Regional Resource Plan)
- Identification of any new needs over the 2015-2025 period and a wires plan to address them.
- Consideration of long-term needs identified in the York Region IRRP

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the results of the adequacy assessment of the transmission facilities and identifies the regional needs.
- Section 7 describes the needs and provides alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2 REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straight forward wires solution.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led

[1] Also referred to as Needs Screening.

stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- NA, SA, and LP phases of regional planning; and,
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

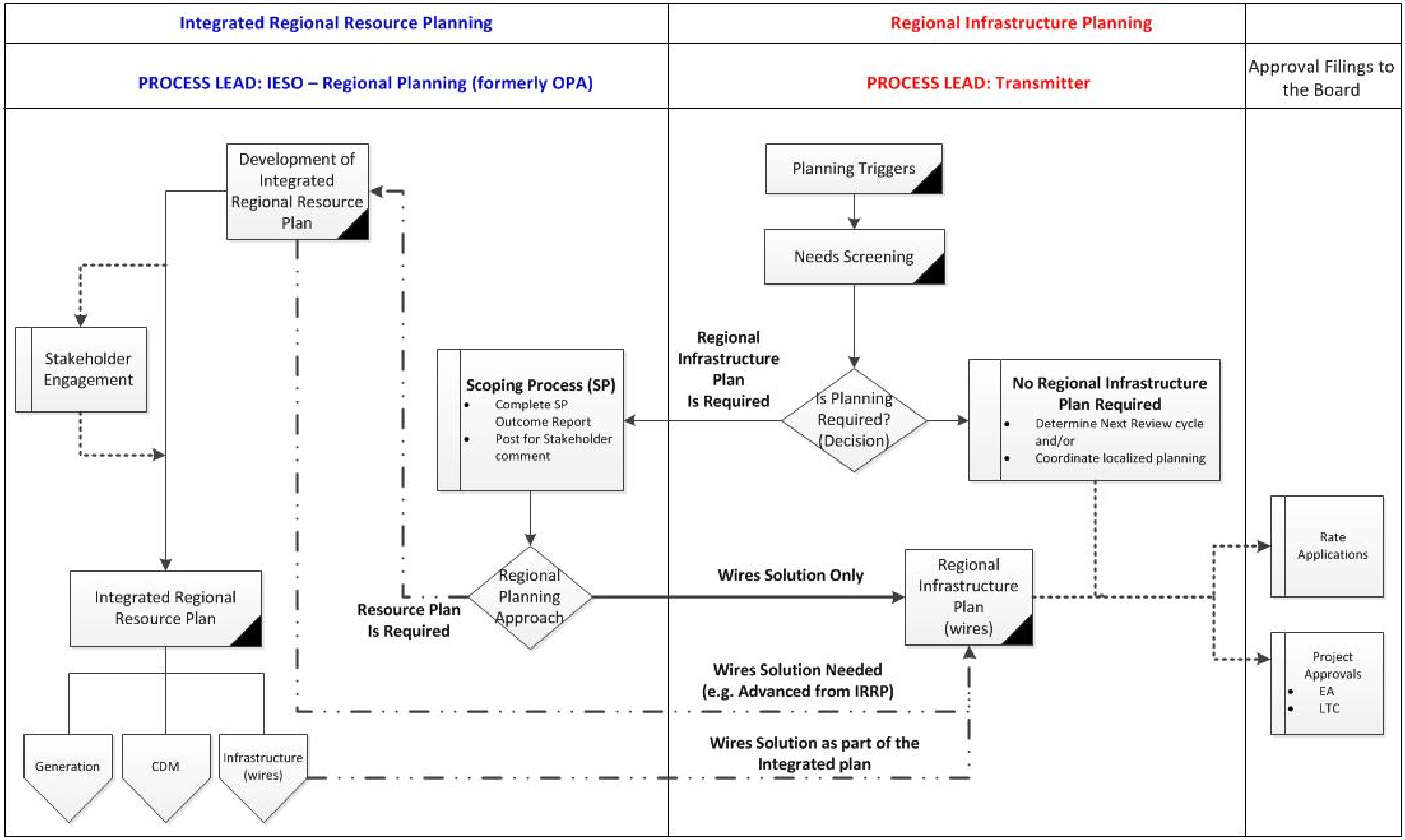


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the Working Group to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any DG or CDM programs.
   - Existing area network and capabilities including any bulk system power flow assumptions; and,
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and mid-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

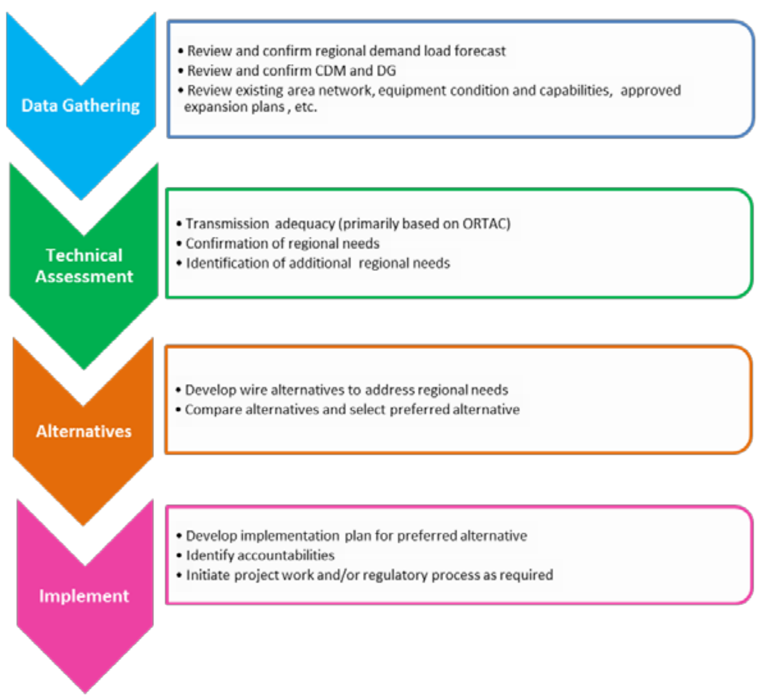


Figure 2-2 RIP Methodology

3 REGIONAL CHARACTERISTICS

THE GTA NORTH REGION IS COMPRISED OF THE YORK SUB-REGION AND THE WESTERN SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIFTEEN 230 KV STEP-DOWN TRANSFORMER STATIONS. THE 2015 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 1900MW.

Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B82V/B83V in King Township.

The April 2015 York Region Integrated Regional Resource Plan (“IRRP”), prepared by the IESO in conjunction with Hydro One, PowerStream and Newmarket-Tay Power, focused solely on the York Sub-Region. The June 2014 GTA North Western Sub-Region Needs Assessment report, prepared by Hydro One, considered the Western Sub-Region. A map of the GTA North Region is shown in Figure 3-1 and a single line diagram of the transmission system is shown in Figure 3-2.

3.1 York Sub-Region

The York Sub-Region was identified as a “transitional” region, as planning activities in the region were already underway before the new regional planning process was introduced. The NA and SA phases were deemed to be complete, and the regional planning process was considered to be in the IRRP phase. An IRRP for the region was completed in April 2015.

For regional planning purposes, the York Sub-Region is further classified into Northern York Area and Southern York Area to reflect the layout of the region’s electricity infrastructure. The Northern York Area encompasses the municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, as well as some load in Simcoe County that is supplied from the same electricity infrastructure. It is supplied by Claireville TS, a 500/230 kV autotransformer station, and three 230 kV transformer stations stepping down the voltage to 44 kV. The York Energy Centre provides a local supply source in Northern York Area. The LDCs supplied in the Northern York Area are Hydro One Distribution, Newmarket-Tay Power Distribution, and PowerStream.

The Southern York Area includes the municipalities of Vaughan, Markham and Richmond Hill. It is supplied by three 500/230 kV autotransformer stations (Claireville TS, Parkway TS, and Cherrywood TS), nine 230 kV transformer stations (includes eight municipal transformer stations) stepping down the voltage to 27.6 kV, and one other direct transmission connected load customer. The LDC supplied in the Southern York Area is PowerStream.

Please see Figure 3-1 and Figure 3-2 for a map and single line diagram of the Sub-Region facilities.

3.2 Western Sub-Region

The Western Sub-Region comprises the Western portion of the municipality of Vaughan. Electrical supply to the sub-region is provided through Claireville TS, a 500/230 kV autotransformer station, and a 230 kV tap (namely, the “Kleinburg tap”) that supplies three 230 kV transformer stations (including one municipal transformer station) stepping down the voltage to 44 kV and 27.6 kV. The LDCs directly supplied in the sub-region are PowerStream and Hydro One Distribution. Embedded LDCs supplied in the sub-region include Enersource, Hydro One Brampton and Toronto Hydro.

During the Needs Assessment phase for the Western Sub-Region, a load restoration need for the loss of V43/V44 was identified. It was recommended that a plan to address this need be included in the IESO led GTA West bulk system planning initiative and therefore this need is not addressed in this RIP.

Please see Figure 3-1 and Figure 3-2 for a map and single line diagram of the Sub-Region facilities.

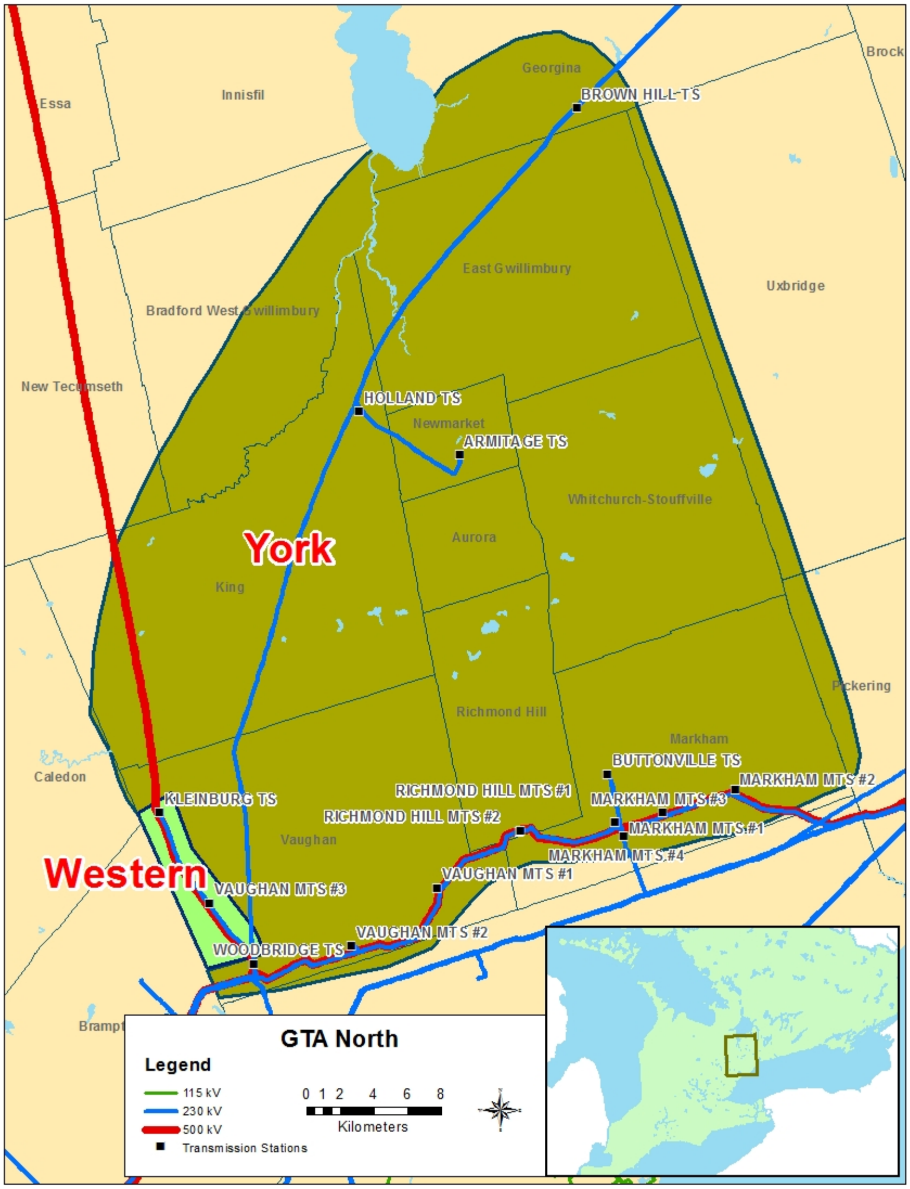


Figure 3-1 GTA North Region – Supply Areas

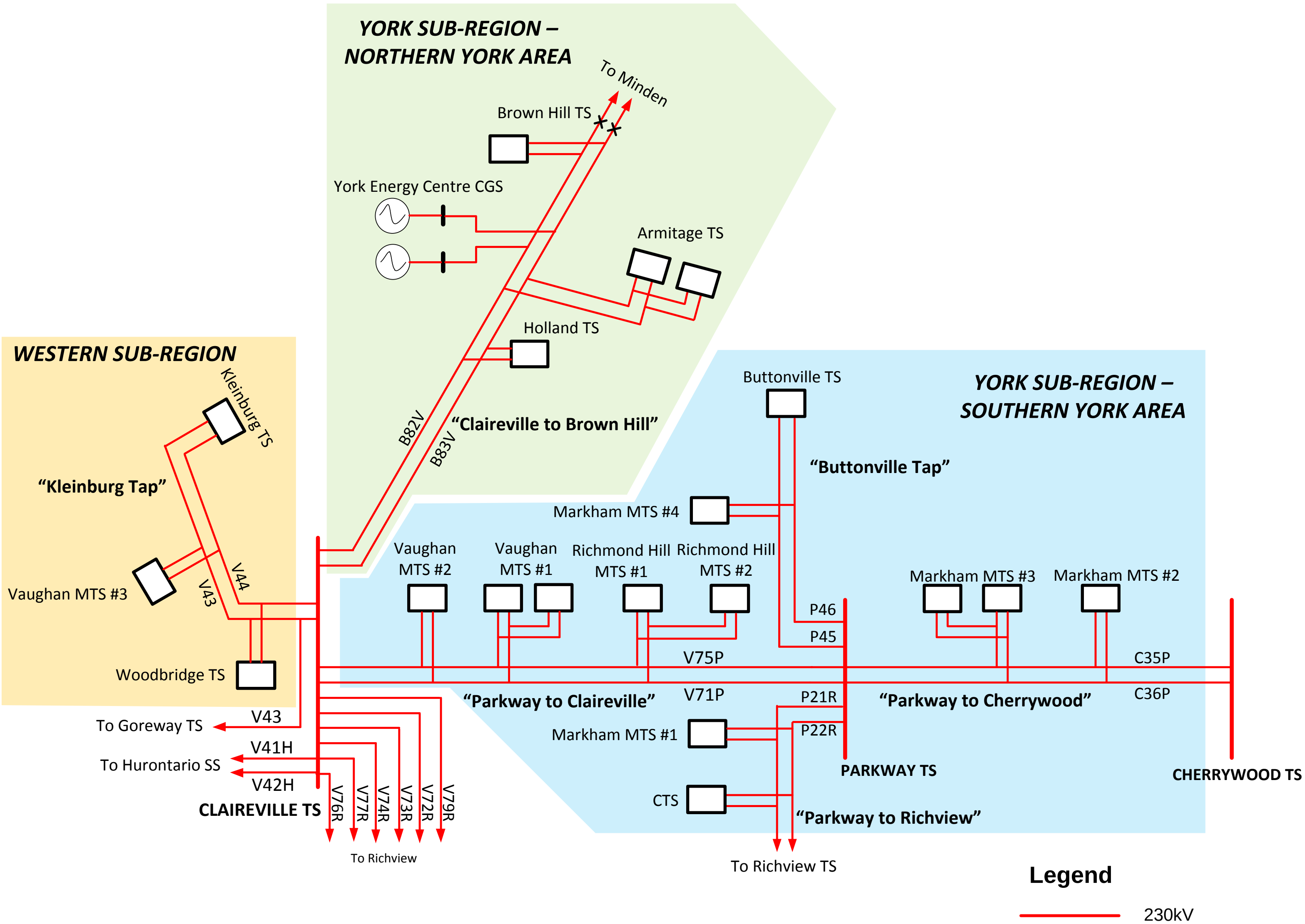


Figure 3-2 GTA North Transmission Single Line Diagram

4 TRANSMISSION FACILITIES COMPLETED OVER THE LAST TEN YEARS OR CURRENTLY UNDERWAY

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GTA NORTH REGION.

A brief listing of the completed development projects along with their in-service dates over the last 10 years is given below:

- Holland TS and low voltage capacitor banks (2009) – to increase transformation capacity for the Northern York Area.
- Parkway 500-230kV autotransformer station (2006) – to increase transmission supply capacity to GTA North
- Parkway x Richmond Hill 230kV double circuit line (2006) – to improve reliability of supply to Southern York Area
- Connect Markham #4 MTS (2009) – to increase transformation capacity for the Southern York Area.
- Increased the size of the capacitor banks at Armitage TS (2006) – to improve reliability of supply to the Northern York Area.
- Connect the York Energy Centre generation facility (2012) – to provide a local source of supply for the Northern York Area.

The following development projects are currently underway:

- Vaughan MTS #4 (2017) – to increase transformation capacity for the Southern York Area.
- Holland breakers, disconnect switches and special protection scheme (2017) – to increase the transmission supply capacity and load restoration capability of the York Sub-Region.

5 FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA North Region is forecast to increase at an average rate of approximately 2.1% annually up 2020, and 1.8% between 2020 and 2025. The growth rate varies across the Region.

Figure 5-1 shows the GTA North Region extreme summer weather coincident peak net load forecast. The coincident peak net load forecast for the individual stations in the GTA North Region is given in Appendix D. The net load forecast takes into account the expected impacts of conservation programs and distributed generation resources.

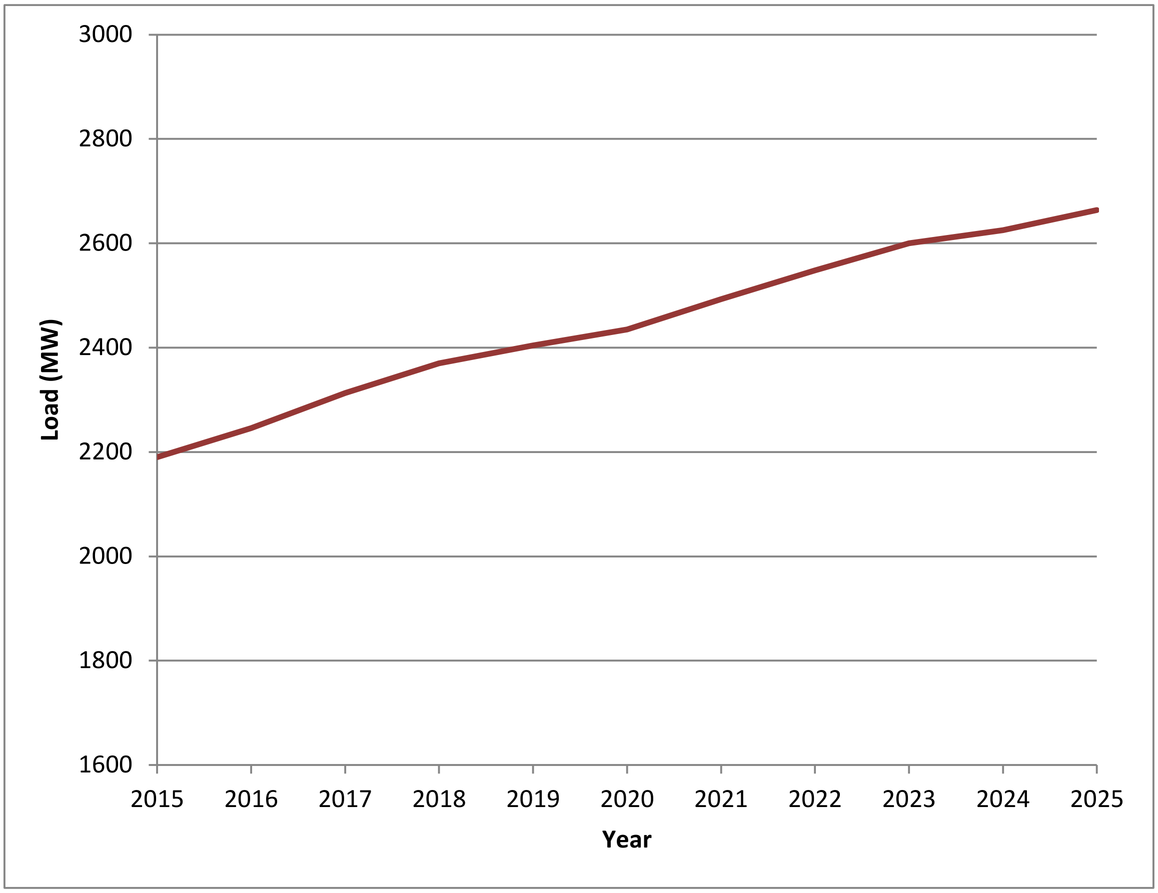


Figure 5-1 GTA North Region Extreme Summer Weather Coincident Peak Net Load Forecast

The station coincident peak net loads used in the RIP are as given in the York Region IRRP for the York Sub-Region[1] and the NA for the Western Sub-Region[2]. RIP Working Group participants confirmed that the load forecast, CDM, and DG information used in the IRRP and NA for the Western Sub-Region was still valid.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP Assessments is 2015-2025.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor which is consistent with ORTAC[4]. Normal planning supply capacity for transformer stations in this region is determined by the summer 10-Day Limited Time Rating ("LTR").

6 ADEQUACY OF FACILITIES AND REGIONAL NEEDS OVER THE 2015-2025 PERIOD

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE GTA NORTH REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM.

Within the current regional planning cycle two regional assessments have been conducted for the GTA North Region; the findings of these studies are input to the RIP:

1) IESO's York Region Integrated Regional Resource Plan – dated April 28, 2015[1]
2) Hydro One's Needs Assessment Report – GTA North – Western Sub-Region – June 27, 2014[2]

The York region IRRP identified a number of regional needs to meet the forecast load demand over the near to mid-term. Due to the immediate nature of the needs the Holland TS Breakers project and the Vaughan #4 MTS project were initiated to provide adequate load supply capability for the York Sub-Region while the York Region IRRP study was still underway. A detailed description and status of the Holland TS Breakers project and other work initiated or planned to meet these needs is given in Section 7.

This RIP reviewed the loading on transmission lines and stations in the GTA North Region assuming the Holland TS Breakers project is in-service using the latest Regional Forecast based on the IRRP load growth scenario as given in Section 5. Sections 6.1- 6.4 present the results of this review and Table 6-1 lists the Region's needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Mid-Term Needs in the GTA North Region

Type	Section	Needs	Timing
Step-down Transformation Capacity	7.1.1	Additional transformation capacity in Vaughan (new Vaughan MTS #4 on circuits B82V/B83V)	2017
	7.1.4	Additional transformation capacity in Markham	2022(3)
	7.1.3	Additional transformation capacity in Vaughan(1)	2023(3)
	7.2.2	Additional transformation capacity in Northern York Area(1)	2023
Transmission Capacity	7.2.1	Capacity of the Claireville to Brown Hill (B82V/B83V) transmission line exceeded	2021
Load Security	7.2.1	Claireville to Brown Hill line (B82V/B83V)	2018
	7.1.2	Parkway to Claireville line (V71P/V75P)	Today
Load Restoration	7.2.1	Claireville to Brown Hill line (B82V/B83V)	Today
	7.1.2	Parkway to Claireville line (V71P/V75P)	Today
	7.3.1	Claireville to Kleinburg line (V43/V44) – restoration need only(2)	Today

(1) There are long-term transmission supply needs associated with new transformation capacity
(2) Restoration need to be assessed as part of the IESO led GTA West bulk system planning initiative
(3) PowerStream is currently reviewing their forecast and has advised that the need date for Markham may change to 2023 and the need date for Vaughan may change to 2026.

6.1 Adequacy of York Sub-Region Facilities

6.1.1 500 and 230 kV Transmission Facilities

All 500 and 230 kV transmission circuits in the GTA North are classified as part of the Bulk Electricity System ("BES"). The 230 kV circuits also serve local area stations within the region. The York Sub-Region is comprised of the following 230 kV circuits. Refer to Figure 3-2.

Southern York Area:

a) Parkway TS to Cherrywood TS 230 kV circuits: C35P and C36P.
b) Parkway TS to Claireville TS 230 kV circuits: V71P and V75P.
c) Parkway TS to Buttonville TS **(**"Buttonville Tap") 230 kV circuits: P45 and P46.
d) Parkway TS to Richview TS 230 kV circuits: P21R and P22R.

Northern York Area:

- Claireville TS to Brown Hill TS 230 kV circuits: B82V and B83V.

The RIP review shows that based on current forecast station loadings and bulk transfers, all 230 kV circuits are expected to be adequate over the study period.

6.1.2 Step down Transformer Station Facilities

There are a total of twelve step-down transformers stations in the York Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in the York Sub-Region

Northern York Area		
Armitage TS	Brown Hill TS	Holland TS
Southern York Area		
Buttonville TS	Markham MTS#1*	Markham MTS#2*
Markham MTS#3*	Markham MTS#4*	Richmond Hill MTS*
Vaughan MTS#1*	Vaughan MTS#2*	Industrial Customer

*Stations owned by PowerStream

Based on the LTR of these load stations, additional capacity is required in Vaughan in 2017 which will be addressed by Vaughan MTS #4. Based on the forecast in Appendix D, additional capacity is required in Markham as early as 2022, and additional capacity will be needed in both Vaughan and Northern York Area as early as 2023. However, PowerStream has advised that their forecast for Markham and Vaughan is currently under review, and that these need dates may change to 2023 and 2026 respectively.

The station loading in each area and the associated station capacity and need dates are summarized in Table 6-3.

Table 6-3 Adequacy of the Step-Down Transformation Facilities in the York Sub-Region

Area/Supply	Capacity (MW)	2015 Summer Loading (MW)*	Need Date
Northern York Area (Armitage, Holland)	485	430	2023
Northern York Area (Brown Hill)	184	74	-
Southern York Area (Markham/Richmond Hill)	956	833	2022
Southern York Area (Vaughan)	612**	459	2023

* Weather adjusted summer peak as per York Region IRRP

** Includes future capacity provided by Vaughan #4 MTS. It does not include Vaughan MTS #3 which is in the Western Sub-Region

6.2 Adequacy of Western Sub-Region Facilities

The Western Sub-Region is comprised of one 230 kV double circuit line V43/V44 between Claireville TS and Kleinburg TS. Refer to Figure 3-2. The line supplies Kleinburg TS, Vaughan MTS #3, and Woodbridge TS. Loading on the V43/V44 line is adequate over the study period.

6.2.1 Step down Transformation Facilities

There are three step-down transmission connected transformation stations in the York Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in the Western Sub-Region

Kleinburg TS
Woodbridge TS
Vaughan MTS#3*

*Station owned by PowerStream

The forecast individual station forecast loads are given in Appendix D. Based on the forecast loads these transformer stations are adequate over the study period. The total station capacity and 2015 loads in Western Sub-Region are given in Table 6-5.

Table 6-5 Adequacy of Step-Down Transformation Facilities – Western Sub-Region

Area/Supply	Capacity (MW)	2015 Summer Loading (MW)	2025 Summer Loading (MW)
Western Sub-Region (Vaughan/Kleinburg)	509	394	409

6.3 Other Items Identified During Regional Planning

6.3.1 Load Security and Restoration in the Southern York Area

The York Region IRRP report had identified load security and restoration needs for loss of the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P. Loading on the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P exceeds the 600 MW limit as per ORTAC security criteria. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The needs and the Working Group recommendations to address the needs are discussed in more detail in Section 7.1.2.

6.3.2 Load Restoration in Western Sub-Region

The Needs Assessment report for the Western Sub-Region had identified a load restoration need for the loss of the Claireville TS to Kleinburg TS 230 kV double circuit line V43/V44. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The Working Group has reviewed the need and reaffirmed the NA recommendation that this need be considered as part of the IESO led GTA West bulk system planning initiative.

6.4 Long-Term Regional Needs

As shown in Section 6.1.2 additional transformation capacity is required in the mid-term. With continued demand growth, the transmission system supplying these stations is also expected to reach its limits. The York Region IRRP had identified the need to coordinate the long term transmission needs with plans to address the station capacity needs.

The GO Rail Electrification Project is an initiative by Metrolinx to convert several rail corridors from a diesel to an electric-based system. GO's Barrie and Stouffville corridors are part of this plan and it is expected that parts of these rail corridors will be supplied by transmission infrastructure in the GTA North Region. At the time of this RIP the electrification project is still in the planning phase, but the impact of this project on the electrical infrastructure in the GTA North Region will need to be monitored as the plans are developed.

The options to address the transformation capacity needs are being reviewed by the Working Group as part of the community engagement activities currently being led by the IESO and LDCs through a Local Advisory Committee process. The Working Group expects to finalize recommendations to address these and associated long-term transmission needs in an IRRP update currently scheduled for 2017.

7 REGIONAL PLANS

This section discusses the needs, wires alternatives and the current preferred wires solution for addressing the electrical supply needs in the GTA North Region. These needs are listed in Table 6-1 and include needs previously identified in the IRRP for the York Sub-Region[1] and the NA for the Western Sub-Region.[2] Needs for which work is already underway are also included.

The near-term needs include needs that arise over the first five years of the study period (2015 to 2020) and the mid-term needs cover the second half of the study period (2020-2025).

7.1 Southern York Area

7.1.1 Increase Transformation Capacity in Vaughan

7.1.1.1 Description

The load forecast reflects substantial growth around the City of Vaughan, mainly around the northern boundaries, as new developments are being made in the area. As a result, based on the net demand forecast a new transformer station is needed by 2017 to ensure adequate transformation capacity is available. This need was also identified as a near-term need in the 2015 York Region IRRP.

7.1.1.2 Recommended Plan and Current Status

Due to the need to provide transformation capacity by 2017, work on building a new station was initiated by PowerStream while the York Region IRRP was still under way. The IRRP Working Group recommended that the new station connect to the Claireville to Brown Hill lines (230 kV circuits B82V/B83V) approximately 12 km north of Claireville TS.[5] Refer to Figure 7.1.

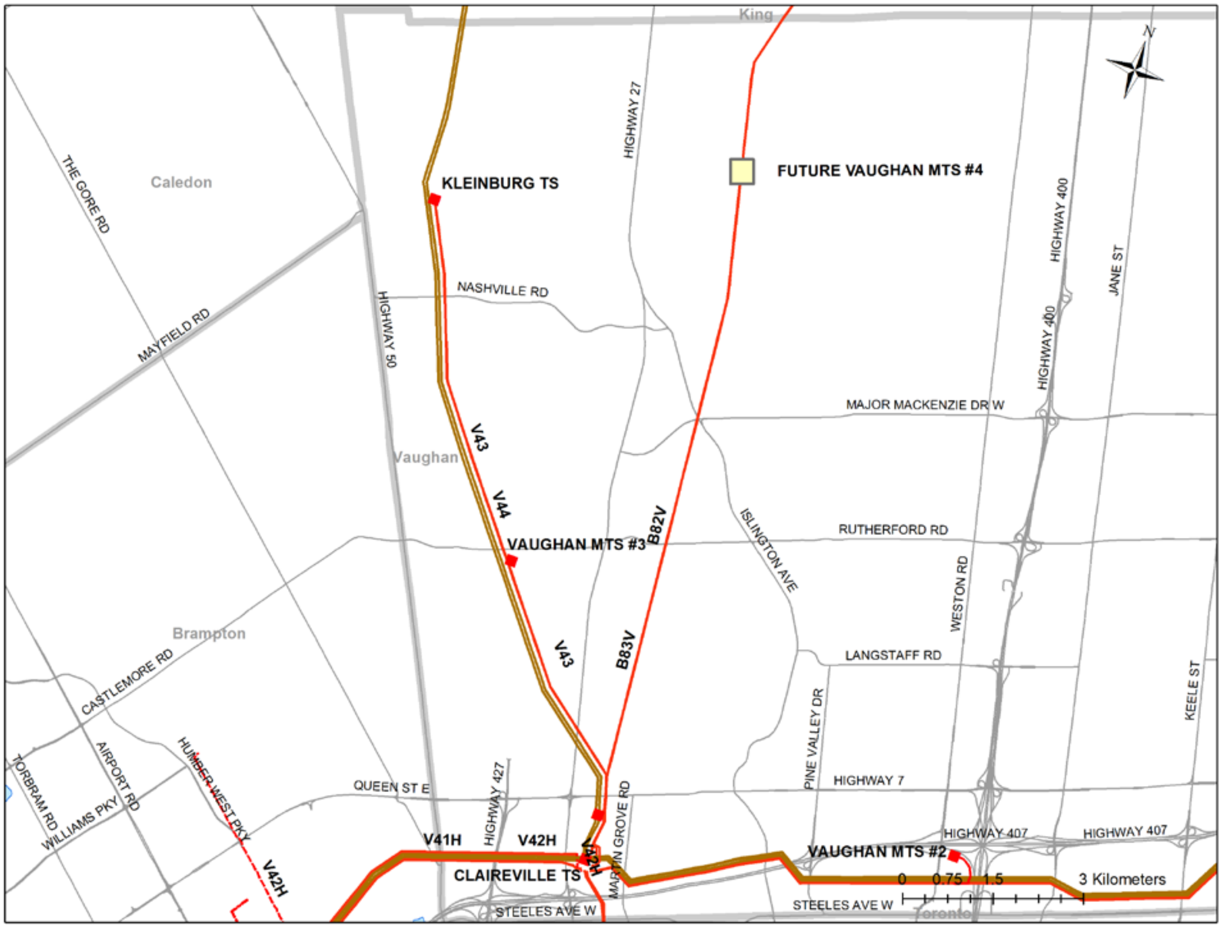


Figure 7-1 Vaughan MTS #4

The new station, Vaughan MTS #4, will provide 153 MW of 27.6 kV transformation capacity and is expected to be in-service by May 2017. Hydro One will construct the line tap to connect the new station to the B82V/B83V circuits.

PowerStream's estimated cost for the station is $25M. The Hydro One line connection cost is currently being estimated. The Hydro One line connection cost will be recovered from rate revenue in accordance with the TSC.

7.1.2 Improve Load Restoration Capability on the Parkway to Claireville Line

7.1.2.1 Description

The Parkway to Claireville line (V71P/V75P) is located on the Parkway Belt and supplies five load stations with a combined load of approximately 700 MW under current summer peak loading conditions. There are two needs identified for this system:

- The load security criteria in ORTAC[4] limits the amount of load that can be interrupted due to the loss of two elements (e.g.: a double circuit line outage) to 600 MW under peak load. On the Parkway to Claireville line, that limit is exceeded.
- The load restoration criteria requires that any load that is interrupted that exceeds 250 MW must be restorable within 30 minutes. At present, this may not be possible on the Parkway to Claireville line under certain operating conditions.

7.1.2.2 Recommended Plan and Current Status

The York Region IRRP recommended the installation of inline switches at the Vaughan MTS #1 junction in order to improve the capability of the system to restore load in the event that both 230 kV circuits V71P/V75P are lost. The switches will not reduce the amount of load that is interrupted, however they will enable Hydro One to quickly isolate the problem and allow the resupply of load to occur expeditiously. This work is covered under the V71P/V75P - Install 230 kV In-line Switches project.

Hydro One has established a project to install the two 230 kV in-line switches onto the V71P/V75P double circuit line with one switch installed on each circuit. The project is currently in the detailed design and estimation phase. The cost of this project is approximately $4-6 million and it is anticipated to be a transmission pool investment. The planned in-service date is May 2018.

7.1.3 Mid-Term Need to Increase Transformation Capacity in Vaughan

7.1.3.1 Description

The planned Vaughan MTS #4 will provide near term transformation capacity for Vaughan beginning in 2017. However, the load forecast shows that additional transformation capacity will be needed in Vaughan as early as 2023. There isn't sufficient transmission capacity available to supply another transformation station on the Claireville to Brown Hill line. Therefore a plan to increase transmission capacity to the area will be required before a plan for a new transformation station can be committed.

7.1.3.2 Recommended Plan and Current Status

Given the time required to build new transmission facilities, the York Region IRRP[1] had advised that it was necessary to identify a preferred alternative no later than 2018 to address both the transformation capacity need as well as the transmission capacity need. However, PowerStream is currently reviewing their load forecast for Vaughan and has advised that the need date for new transformation capacity may change to 2026. An update to the York Region IRRP is currently scheduled for 2017 to review the need date and develop a preferred plan for building and connecting additional transformation capacity in Vaughan.

7.1.4 Mid-Term Need to Increase Step-Down Transformation Capacity in Markham

7.1.4.1 Description

The step-down transformation capacity in Markham will be exceeded as early as 2022. The York Region IRRP has identified that additional transmission facilities will be required to supply the new station. It is expected that the IESO will continue to explore non-wires options, in addition to wires options, through the IRRP process.

New developments attributable to forecasted load growth in the area are generally further north, away from existing transmission facilities. The ORTAC's[4] load restoration criteria will need to be considered in the further development of any detailed wires options. Non-wires options are beyond the scope of this RIP, but there are two main wires options for supplying a new Markham transformer station.

Option 1 - Connect to 230kV circuits C35P/C36P between Parkway TS and Cherrywood TS
The Parkway to Cherrywood line (C35P/C36P) connects two major bulk transmission stations, Parkway TS and Cherrywood TS, and also supplies load stations Markham MTS #3 (2 stations) and Markham MTS #2. There is transmission capacity available on these circuits to connect another transformer station.

Option 2 – Connect to 230kV double circuit line P45/P46 between Parkway TS and Buttonville TS
The Buttonville Tap (P45/P46) currently supplies two stations, Markham MTS #4 and Buttonville TS radially from Parkway TS. The transmission capacity on these circuits is thermally limited by a section less than 1 km long, so it would be necessary to increase the thermal capacity of these circuits in order to fully supply another station.

Extending the transmission circuits discussed would allow the point of supply to be nearer to the area of expected load growth and therefore reduce the amount of distribution facilities that would be needed.

7.1.4.2 Recommended Plan and Current Status

The existing transmission lines are not near the areas of expected load growth so the additional transmission costs to supply a new station nearer to the load need to be considered alongside the distribution costs. PowerStream estimates the incremental distribution costs for a station supplied by existing transmission lines to be on the order of $10-$50M higher than would be required for a station located nearer to the load.

Given that this need is a mid-term need, the York Region IRRP[1] identified a number of non-wires approaches that may address or defer the need for further transformation capacity. Such alternatives include CDM, DG, large generation and other local community initiatives and further monitoring of the load growth was recommended. In order to have facilities in-service to meet a summer 2022 need, it is recommended to continue wires planning, in addition to other non-wires alternatives, to meet this need and to identify a preferred solution by the end of 2017. This timeline allows approximately 4.5 years for detailed estimating, engineering, approvals, construction and commissioning if a wires option is identified as the preferred alternative. However, PowerStream is currently reviewing their load forecast for Markham and has advised that the need date for new transformation capacity may change to 2023. It is expected that the need date will be reviewed and a preferred solution will be identified in the York Region IRRP update process which is currently scheduled for 2017.

7.2 Northern York Area

7.2.1 Increase Capacity and Load Restoration Capability on Claireville to Brown Hill Line

The transmission capacity, load security and load restoration requirements are near-term needs for the Claireville to Brown Hill line (circuits B82V/B83V). These needs were identified in the 2015 York Region IRRP[1]. The Claireville to Brown Hill transmission line and local generation (York Energy Centre) combined are capable of supplying 600 MW of load. This limit is based on the ORTAC[4] load security criteria, which limits the amount of load that can be lost for two elements out of service to 600 MW. This is the most restrictive limit in this system and therefore defines the amount of load that can be supplied. With continued load growth at the stations supplied by this line as well as the future Vaughan #4 MTS (described in section 7.1), it is expected that load security criteria will be exceeded by 2018 based on the net demand forecast.

The load restoration need is based on the ORTAC[4] load restoration criteria that requires any load lost exceeding 250 MW to be restorable within 30 minutes. Based on the current net peak demand forecast, the loss of the Claireville to Brown Hill line will exceed this threshold and there are insufficient transmission and distribution facilities to restore sufficient load within 30 minutes in order to respect the criteria.

7.2.1.1 Recommended Plan and Current Status

Hydro One is expanding the Holland TS station to include two, 230kV inline circuit breakers and six motorized disconnect switches to increase the transmission capacity as well as the load restoration capability of this system. The project includes a load rejection and generation rejection special protection scheme (“SPS”). The purpose of the SPS is to ensure that the transmission system does not get overloaded following respected contingencies. The IESO (formerly the Ontario Power Authority) stated their support for this project in a letter to Hydro One dated June 14, 2013.[5] The planned in-service date for this project is Q4 2017 at an estimated cost of $32 million. This is anticipated to be a transmission pool cost and LDCs are not expected to pay any contribution.

The station service supply to the York Energy Centre is currently supplied from Holland TS. However, a low-voltage breaker failure event at Holland TS or a double circuit 230 kV contingency can result in an interruption to the station service supply to York Energy Centre and therefore the loss of all generation output until the station service can be restored from the alternate source. The IESO intends to develop a plan to address this issue in the York Region IRRP update currently scheduled for 2017.

7.2.2 Mid-Term Need to Increase Transformation Capacity

Based on the growth forecast for the Northern York Area, the combined loading on Armitage TS and Holland TS will exceed their combined summer 10-Day LTR as early as 2023. There is 44 kV transfer capability between these stations on the distribution system so the timing of the need is based on the combined capability of both stations. The IRRP indicated that the Claireville to Brown Hill circuits do not have sufficient capacity to fully supply another transformation station in Northern York Area after the Vaughan #4 MTS connection and Holland breakers project and therefore there is a long-term need to increase transmission capability to supply a new station. However, as noted in the York Region IRRP, under a low growth scenario in the long term, the demand in Northern York Area will stabilize to within the capacity of existing stations to beyond 2033.

7.2.2.1 Recommended Plan and Current Status

The York Region IRRP[1] identified a number of non-wires alternatives that may address or defer the need for further transformation capacity in Northern York Area. Such alternatives include CDM, DG, large generation and other local community initiatives. However, given that the need date for this area may be as early as 2023, it is necessary to identify a preferred alternative by 2018 that addresses both the transformation capacity need as well as the transmission capacity need. The working group expects to finalize a plan and recommendations to address these needs in an IRRP update currently scheduled for 2017.

7.3 Western Sub-Region

7.3.1 Load Restoration Need for the Claireville to Kleinburg Line

The three stations in this sub-region, Woodbridge TS, Vaughan #3 MTS and Kleinburg TS, are supplied by two radial 230kV circuits, V43 and V44, originating from Claireville TS. Inherent to radial configuration, the loss of these two circuits will interrupt supply to loads and consequently load restoration times as per the ORTAC[4] may not be met. This need was identified during the NA for this sub-region and also in the Northwest GTA IRRP[6] and it was subsequently recommended that this need be addressed in the IESO's GTA West bulk system planning initiative.

7.4 Long Term Future Transmission Corridor to the GTA North Region

The GTA West RIP recommended the establishment of a future-use transmission corridor, to address growth-related needs in the GTA West region. In addition to addressing needs in the GTA West region, development of an eastern portion of this corridor through the City of Vaughan is also a possible option that could address the long-term supply needs identified for York Region. It is therefore recommended that, in the development of the long-term plans for the GTA West and GTA North regions, consideration be given to coordinating solutions to meet the needs of both regions when assessing options for each region individually.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA NORTH REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in Table 8-1.

Table 8-1: Regional Plans – Needs Identified in the Regional Planning Process

No.	Need Description
I	Vaughan Transformation Capacity (Near Term)
II	Northern York Area Load Security on B82V/B83V
III	Northern York Area Load Restoration on B82V/B83V
IV	Parkway to Claireville – Load Security on V71P/V75P
V	Parkway to Claireville – Load Restoration on V71P/V75P
VI	Markham Transformation Capacity (Mid-term)
VII	Vaughan Transformation Capacity (Mid-term)
VIII	Northern York Area Transformation Capacity (Mid-term)
IX	Kleinburg Tap – Load Restoration on V43/V44

Next Steps, Lead Responsibility, and Timeframes for implementing the wires solutions for the needs are summarized in Table 8-2 below. Investments to address the needs where there is time to make a decision (Needs No. VI, VII, and VIII), will be reviewed and finalized in the next regional planning cycle. Need No. IX will be addressed in the IESO GTA West bulk system planning initiative.

Table 8-2: Regional Plans – Next Steps, Lead Responsibility and Planned In-Service Dates

Id	Project	Next Steps	Lead Responsibility	I/S Date	Estimated Cost	Needs Mitigated
1	Vaughan #4 MTS	LDC to carry out the work	PowerStream	2017	$25M	I
2	Holland Breakers and SPS	Transmitter to carry out the work	Hydro One	2017	$32M	II, III
3	Parkway Belt Switches	Transmitter to carry out the work	Hydro One	2018	$4-6M	V

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. Due to the timing of the mid-term needs, the IRRP proposed that the process be updated in advance of the regular 5-year review schedule. The York Region IRRP is currently scheduled to be updated in 2017.

REFERENCES

[1]. Independent Electricity System Operator, "York Region Integrated Regional Resource Plan", 28 April 2015.
http://www.ieso.ca/Documents/Regional-Planning/GTA_North/2015-York-Region-IRRP-Report.pdf

[2]. Hydro One, "Needs Screening Report, GTA North Region – Western Sub Region", 27 June 2014.
http://www.hydroone.com/RegionalPlanning/GTANorth/Documents/Needs%20Assessment%20Report%20-%20GTA%20North%20-%20Western%20Subregion.pdf

[3]. "Planning Process Working Group (PPWG) Report to the Board The Process for Regional Infrastructure Planning in Ontario", May 17, 2013
http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2011 0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

[4]. Independent Electricity System Operator, "Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0"
http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

[5]. Hydro One, "OPA Letter – Initiating Near-Term Transmission Components of the York Region Integrated Regional Resource Plan," 14 June 2013.
http://www.hydroone.com/RegionalPlanning/GTANorth/Documents/OPA%20Letter%20to%20Hydro%20One%20%20Regarding%20%20York%20Subregion.pdf

[6]. Independent Electricity System Operator, "Northwest Greater Toronto Area Integrated Regional Resource Plan", 28 April 2015
http://www.ieso.ca/Documents/Regional-Planning/GTA_West/2015-Northwest-GTA-IRRP-Report.pdf

APPENDIX A: STATIONS IN THE GTA NORTH REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Kleinburg TS T1/T2 27.6 Kleinburg TS T1/T2 44	230/27.6 230/44	V43/V44
Vaughan MTS #3	230/27.6	V43/V44
Woodbridge TS T3/T5 27.6 Woodbridge TS T3/T5 44	230/27.6 230/44	V43/V44
Armitage TS T1/T2/T3/T4	230/44	B82V/B83V
Brown Hill TS T1/T2	230/44	B82V/B83V
Holland TS T1/T2	230/44	B82V/B83V
Buttonville TS T3/T4	230/27.6	P45/P46
Markham MTS #1	230/27.6	P21R/P22R
Markham MTS #2	230/27.6	C35P/C36P
Markham MTS #3 T1/T2/T3/T4	230/27.6	C35P/C36P
Markham MTS #4	230/27.6	P45/P46
Richmond Hill MTS #1	230/27.6	V71P/V75P
Richmond Hill MTS #2	230/27.6	V71P/V75P
Vaughan MTS #1 T1/T2/T3/T4	230/27.6	V71P/V75P
Vaughan MTS #2	230/27.6	V71P/V75P

APPENDIX B: TRANSMISSION LINES IN THE GTA NORTH REGION

Location	Circuit Designations	Voltage (kV)
Claireville TS to Brown Hill TS, Armitage TS and Holland TS	B82V/B83V	230
Claireville TS to Kleinburg TS, Vaughan MTS #3 and Woodbridge TS	V43/V44	230
Claireville TS to Vaughan MTS #1, Vaughan MTS #2, Richmond Hill MTS #1, Richmond Hill MTS #2, Parkway TS	V71P/V75P	230
Parkway TS to Markham MTS #1 and CTS	P21R/P22R	230
Parkway TS to Buttonville TS and Markham MTS #4	P45/P46	230
Parkway TS to Markham MTS #2, Markham MTS #3, Cherrywood TS	C35P/C36P	230

APPENDIX C: DISTRIBUTORS IN THE GTA NORTH REGION

<table>
<tr><th>Distributor Name</th><th>Station Name</th><th>Connection Type</th><th>Area/Region</th></tr>
<tr><td>Enersource Hydro Mississauga Inc.</td><td>Woodbridge TS</td><td>Dx</td><td>Western Sub-Region</td></tr>
<tr><td>Hydro One Brampton Networks Inc.</td><td>Woodbridge TS</td><td>Dx</td><td>Western Sub-Region</td></tr>
<tr><td rowspan="5">Hydro One Networks Inc. (Distribution)</td><td>Armitage TS</td><td>Tx</td><td>Northern York Area</td></tr>
<tr><td>Brown Hill TS</td><td>Tx</td><td>Northern York Area</td></tr>
<tr><td>Holland TS</td><td>Tx</td><td>Northern York Area</td></tr>
<tr><td>Kleinburg TS</td><td>Tx</td><td>Western Sub-Region</td></tr>
<tr><td>Woodbridge TS</td><td>Tx</td><td>Western Sub-Region</td></tr>
<tr><td rowspan="2">Newmarket-Tay Power Distribution Ltd.</td><td>Armitage TS</td><td>Tx</td><td>Northern York Area</td></tr>
<tr><td>Holland TS</td><td>Tx</td><td>Northern York Area</td></tr>
<tr><td rowspan="16">PowerStream Inc.</td><td rowspan="2">Armitage TS</td><td>Dx</td><td>Northern York Area</td></tr>
<tr><td>Tx</td><td>Northern York Area</td></tr>
<tr><td>Buttonville TS</td><td>Tx</td><td>Southern York Area</td></tr>
<tr><td>Holland TS</td><td>Dx</td><td>Northern York Area</td></tr>
<tr><td>Kleinburg TS</td><td>Tx</td><td>Western Sub-Region</td></tr>
<tr><td>Markham MTS #1</td><td>Tx</td><td>Southern York Area</td></tr>
<tr><td>Markham MTS #2</td><td>Tx</td><td>Southern York Area</td></tr>
<tr><td>Markham MTS #3</td><td>Tx</td><td>Southern York Area</td></tr>
<tr><td>Markham MTS #4</td><td>Tx</td><td>Southern York Area</td></tr>
<tr><td>Richmond Hill MTS #1</td><td>Tx</td><td>Southern York Area</td></tr>
<tr><td>Richmond Hill MTS #2</td><td>Tx</td><td>Southern York Area</td></tr>
<tr><td>Vaughan MTS #1</td><td>Tx</td><td>Southern York Area</td></tr>
<tr><td>Vaughan MTS #2</td><td>Tx</td><td>Southern York Area</td></tr>
<tr><td>Vaughan MTS #3</td><td>Tx</td><td>Western Sub-Region</td></tr>
<tr><td rowspan="2">Woodbridge TS</td><td>Dx</td><td>Western Sub-Region</td></tr>
<tr><td>Tx</td><td>Western Sub-Region</td></tr>
<tr><td>PowerStream Inc.[Barrie]</td><td>Holland TS</td><td>Dx</td><td>Northern York Area</td></tr>
<tr><td>Toronto Hydro Electric System Limited</td><td>Woodbridge TS</td><td>Dx</td><td>Western Sub-Region</td></tr>
<tr><td>Veridian Connections Inc.</td><td>Armitage TS</td><td>Dx</td><td>Northern York Area</td></tr>
</table>

APPENDIX D: GTA NORTH REGION LOAD FORECAST 2015-2025

Stations Net Coincident Peak Load Forecast (MW)

Station Name	LTR*	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Kleinburg 28 kV (BY)	97	54	56	58	59	63	64	66	69	70	70	70
Kleinburg 44 kV (EQ)	99	62	63	64	65	65	65	65	66	66	66	66
Vaughan 3 MTS 28 kV	153	153	153	153	153	153	153	153	153	153	153	153
Woodbridge 44 kV (EQ)	80	53	54	54	54	53	52	52	52	52	52	52
Woodbridge 28 kV (BY)	80	72	71	71	71	70	69	69	68	68	68	68
Holland TS 44 kV	168	136	138	142	144	145	146	149	152	154	156	158
Armitage TS 44 kV	317	294	299	306	312	314	317	324	330	336	338	344
Brown Hill TS 44 kV	184	74	76	79	81	83	85	88	90	93	95	98
Richmond Hill MTS 28 kV	254	254	254	254	254	254	254	254	254	254	254	254
Vaughan 1 MTS 28 kV	306	306	306	306	306	306	306	306	306	306	306	306
Vaughan 2 MTS 28 kV	153	153	153	153	153	153	153	153	153	153	153	153
Vaughan 4 MTS	153	0	24	47	69	83	97	119	140	160	170	185
Buttonville TS 28 kV	166	153	153	153	153	153	153	153	153	153	153	153
Markham 1 MTS 28 kV	81	81	81	81	81	81	81	81	81	81	81	81
Markham 2 MTS 28 kV	101	101	101	101	101	101	101	101	101	101	101	101
Markham 3 MTS 28 kV	202	202	202	202	202	202	202	202	202	202	202	202
Markham 4 MTS 28 kV	153	42	62	89	112	125	137	158	178	198	207	220

* LTR based on 0.9 power factor

APPENDIX E: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 2B
Section B
Appendix E
ORIGINAL
(105 pages)

CENTRAL TORONTO AREA
INTEGRATED REGIONAL RESOURCE PLAN

Part of the Metro Toronto Planning Region | April 28, 2015

ieso
Independent Electricity System Operator

Integrated Regional Resource Plan

Central Toronto Area

The Integrated Regional Resource Plan ("IRRP") was prepared by the IESO pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066

This IRRP was prepared on behalf of the Central Toronto Area Working Group, which included the following members:

- Independent Electricity System Operator
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

The Central Toronto Working Group assessed the adequacy of electricity supply to customers in the Central Toronto Area over a 25-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Central Toronto Area; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

Central Toronto Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. Central Toronto Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

Table of Contents

List of Figures

List of Tables

List of Appendices

List of Abbreviations

Abbreviation	Description
BES	Bulk Electric System
CDM	Conservation and Demand Management
CEMLC	Commercial Energy Management and Load Control
CEP	Community Energy Plan
CHP	Combined Heat and Power
DE	District Energy
DG	Distributed Generation
EM&V	Evaluation, Measurement and Verification
EUE	Expected Unserved Energy
EV	Electric Vehicle
FIT	Feed-in Tariff
GEA	Green Energy Act, 2009
GFA	Gross Floor Area
GHG	Green House Gas
GTA	Greater Toronto Area
GWh	Gigawatt hour
HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IPSP	Integrated Power System Plan (2007)
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
kW	Kilowatt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LTEP	Long-Term Energy Plan (2013)
LTR	Limited Time Rating
MPAC	Municipal Property Assessment Corporation
MVA	Megavolt-ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portlands Energy Centre
PPWG	Planning Process Working Group
PRA	Probabilistic Reliability Assessment

PSS®E	Power System Simulator for Engineering
PV	Photovoltaic (Solar)
RIP	Regional Infrastructure Plan
SCGT	Single-Cycle Gas Combustion Turbine
TGS	Toronto Green Building Standard
THESL	Toronto Hydro-Electric System Limited
TS	Transformer Station
Working Group	Central Toronto Area Working Group

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of Central Toronto. The report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group (the "Working Group") composed of the IESO, Toronto Hydro-Electric System ("Toronto Hydro" or "THESL") and Hydro One Networks Inc. ("Hydro One" or "HONI").

The Central Toronto Area has been undergoing extensive redevelopment, which has resulted in electricity demand growth that is placing pressure on parts of the electricity system serving the area. The City of Toronto's expectation is that the area will experience substantial continued population and economic growth in the coming decade. Therefore, there is a need for integrated regional electricity planning to ensure that the electricity system can support the pace of development over the long term.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB regional planning process, transmitters, distributors and the IESO are required to carry out regional planning activities for the 21 electricity planning regions across the province at least once every five years.

The area covered by the Central Toronto IRRP is a sub-region of the "Metro Toronto" region established through the Ontario Energy Board's ("OEB" or "Board") regional planning process. This report contributes to fulfilling the requirements for the Metro Toronto region as required by the IESO's OEB licence. Hydro One completed a Needs Screening for the remainder of Metro Toronto ("Metro Toronto Northern sub-region") in 2014 and found that no regionally coordinated planning was required for the remainder of the region.

This IRRP for Central Toronto identifies and co-ordinates the many different options to meet customer needs in Central Toronto over the next 25 years.[1] Specifically, this IRRP identifies investments for immediate implementation necessary to meet near and medium-term needs. This IRRP also identifies a number of options to meet longer-term needs, but given forecast

[1] The long-term planning horizon for a Regional Plan is typically 20 years. In the case of Central Toronto, Toronto Hydro provided a forecast covering a 25 year period. The Working Group agreed to assess needs based on the 25 year forecast.

uncertainty, the potential for technological change, and the longer development lead time, the plan maintains flexibility for longer-term options and does not recommend specific projects at this time. Instead, the long-term plan identifies near-term actions to develop alternatives and engage with the community, to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle, scheduled for 2020 or sooner, depending on demand growth, so that the results of these actions can inform a decision, should one be needed at that time.

This report is organized as follows:

- A summary of the recommended plan for Central Toronto is provided in Section 2;
- The process used to develop the plan is discussed in Section 3;
- The context for electricity planning in the Central Toronto Area and study scope is discussed in Section 4;
- Demand forecast scenarios, and conservation and distributed generation ("DG") assumptions are described in Section 5;
- Near-term and medium-term electricity needs are presented in Section 6;
- Alternatives and recommendations for meeting near- and medium-term needs are addressed in Section 7;
- Options for meeting long-term needs are provided in Section 8;
- A summary of community, aboriginal and stakeholder engagement to date in developing this IRRP and going forward is provided in Section 9; and
- A conclusion is provided in Section 10;

2. The Integrated Regional Resource Plan

Near/Medium-Term Needs

- Meeting standards / improving supply security at Manby TS and Leaside TS – **today to 2018**
- Ensuring sufficient capacity to supply near term growth in west Toronto – **2018**
- Ensuring sufficient supply capacity on the 230 kV transmission system between Richview TS and Manby TS – **2018**
- Ensuring sufficient capacity to supply near term growth in downtown Toronto – **2021**

The Central Toronto IRRP addresses the sub-region's electricity needs over the next 25 years, based on the application of the IESO's Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP identifies needs that are forecast to arise in the near term (0-5 years), medium term (5-10 years) and long term (10-25+ years). These planning horizons are distinguished in the IRRP to reflect the different level of commitment required over these time horizons. The plans to address these timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria, including reliability, cost and feasibility; and, in the near term, it seeks to maximize the use of the existing electricity system. For the near term, the IRRP identifies specific investments that need to be immediately implemented or that are already being implemented. This is necessary to ensure that they are in service in time to address the region's more urgent needs, respecting the lead time for their development.

For the medium and long term, the IRRP identifies a number of alternatives to meet needs. However, as these needs are forecast to rise further in the future, it is not necessary (nor would it be prudent given forecast uncertainty and the potential for technological change) to commit to specific projects at the present time. Instead, near-term actions are identified to develop alternatives and engage with the communities, to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle, so that their results can inform a decision at that time.

The needs and recommended actions for the near/medium-term and long-term plans are summarized below.

2.1 Near- and Medium-Term Plan

The plan to meet Central Toronto's near- and medium-term electricity needs was developed with a view to economically maximizing the use of the existing system while ensuring adequate and reliable supply is in place to meet the growth needs of the region.

The core elements of the near- and medium-term plan include measures to meet the reliability standards and enhance supply security in the area, continuing with implementation of conservation, developing DG, and ensuring that infrastructure options are available to connect new customers and meet demand growth requirements in a timely manner.

Detailed recommendations are provided in Section 7. A summary of the plan's recommended actions is as follows:

1. Reconfigure the tap points of Horner TS on the Richview to Manby 230 kV lines to improve the distribution of loading on the 230 kV system by better balancing the loadings using existing infrastructure (completed by Hydro One in 2014).
2. Implement Special Protection Systems to address supply security and ensure that the reliability standards are met for breaker failure contingencies at the major transformer stations serving Central Toronto (Manby TS and Leaside TS).
3. Implement area-specific conservation options in order to defer 230 kV transmission line capacity needs.
4. Conduct further work to identify opportunities for distributed generation resources within the Central Toronto Area.
5. Proceed with work for increasing transformer station capacity in west Toronto by 2018, and in the downtown core by 2021.
6. Proceed with detailed investigation of the infrastructure options to provide capacity relief for the Richview – Manby 230 kV transmission corridor.
7. Investigate and implement cost-effective options for enhancing supply security and restoration capability following multiple element contingencies in Central Toronto.
8. Conduct further work to assess options for increasing system resiliency for extreme events.

2.2 Long-Term Plan

In the long term, Central Toronto's electricity system is expected to reach its capacity to supply growth at the two major transformer stations and at key transmission facilities supplying the area as early as the mid-2020s. Uncertainty in the long-term demand forecast, and the opportunity for conservation and DG resources to reduce the area's reliance on the delivery of provincial grid supply via the transmission system, could however defer these needs further into the future. The long-term plans for Central Toronto will be integrated and assessed with plans as a whole for the Metro Toronto Region.

Long-Term Needs

- Ensuring sufficient capacity to supply long- term growth in Toronto

The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise. A number of alternatives are possible to meet the region's long-term needs. While specific solutions do not need to be committed today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives, to support decision-making in the next iteration of the IRRP.

Detailed recommendations are provided in Section 8. A summary of the recommended actions to support the long-term plan are summarized as follows:

1. Establish a Local Advisory Committee to inform the long-term vision for electricity supply in the area.
2. Continue to engage with stakeholders and the community to develop community-based solutions.
3. Monitor demand growth, conservation achievement and DG uptake.
4. Initiate the next Regional Planning Cycle early, if needed.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region – defined by common electricity supply infrastructure over the near, medium, and long term, and develops a plan to ensure cost-effective reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the Ontario Power Authority ("OPA") carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In 2012, the Ontario Energy Board convened a Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders. In May 2013, the PPWG released the Working Group Report to the Board, setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group report and a phased schedule for completion of regional planning was outlined. The Board endorsed the Working Group Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA licence changes required it to lead a number of aspects of regional planning including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence became the responsibilities of the new IESO.

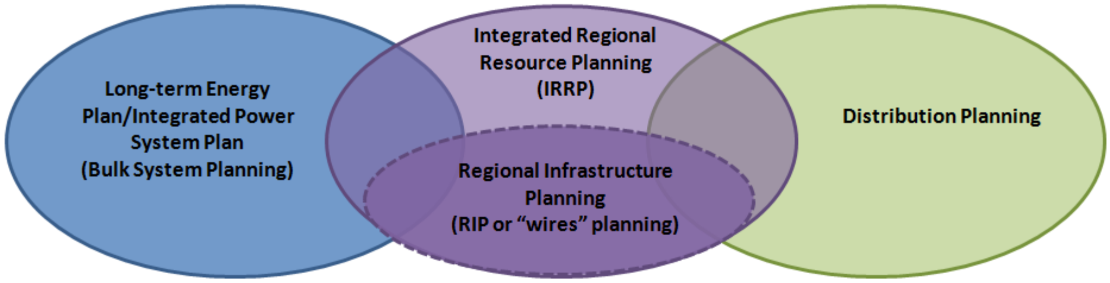
The regional planning process begins with a Needs Assessment process performed by the transmitter, which determines whether there are electricity needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment process to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission and distribution solutions, or whether a straightforward "wires" solution is the only option. If the latter applies, then a transmission and distribution focused Regional Infrastructure Plan ("RIP") is required. The Scoping Assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Assessment process – identifying whether an IRRP, RIP, or no regional coordination is required – and a preliminary Terms of Reference. If an IRRP is the identified outcome, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and is required to complete the plan within six months. Both RIPs and IRRPs are to be updated at least every five years.

The final IRRPs and RIPs are to be posted on the IESO and the relevant transmitter websites, and can be used as supporting evidence in a rate hearing or Leave to Construct application for specific infrastructure investments. These documents may also be used by municipalities for planning purposes and other parties to better understand local electricity growth, conservation opportunities and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one form of electricity planning that is undertaken in Ontario. There are three broad types of electricity planning in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Figure 3-1: Levels of Electricity System Planning



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capability
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- & medium-term focused

Distribution Network Planning

- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified Dx facilities)
- Distribution system reliability (capacity & security)
- Distribution connected generation & CDM resources
- LDC demand forecasts
- Near- & medium-term focused

Planning at the bulk system level typically considers the 230 kV and 500 kV transmission network. Bulk system planning considers the major transmission facilities and assesses the resources needed to adequately supply the province. Bulk system planning is carried out by the IESO. Distribution planning, which is carried out by local distribution companies ("LDC"), looks at specific investments on the low voltage distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost-effectiveness it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of the needs. Regional planning aligns near- and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they allow an evaluation of the multiple options available to meet needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

3.2 The IESO's Approach to Integrated Regional Resource Planning

IRRPs assess electricity system needs for a region over a 20-year period, except in cases where the Working Group participants agree on a different planning horizon.[2] The outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan—the near- and medium-term—than for the longer-term period, 10 to 20+ years. The plan for the first 10 years is developed based on best available information on demand, conservation, and other local developments. Given the long lead-time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead-times; as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future, and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and regional Working Group (see Section 3.3 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and First Nation and Métis communities, who may have an interest in the area. The steps of an IRRP are illustrated in Figure 3-2 below.

The IRRP report documents the inputs, findings and recommendations developed through the process described above, and provides recommended actions for the various entities that are

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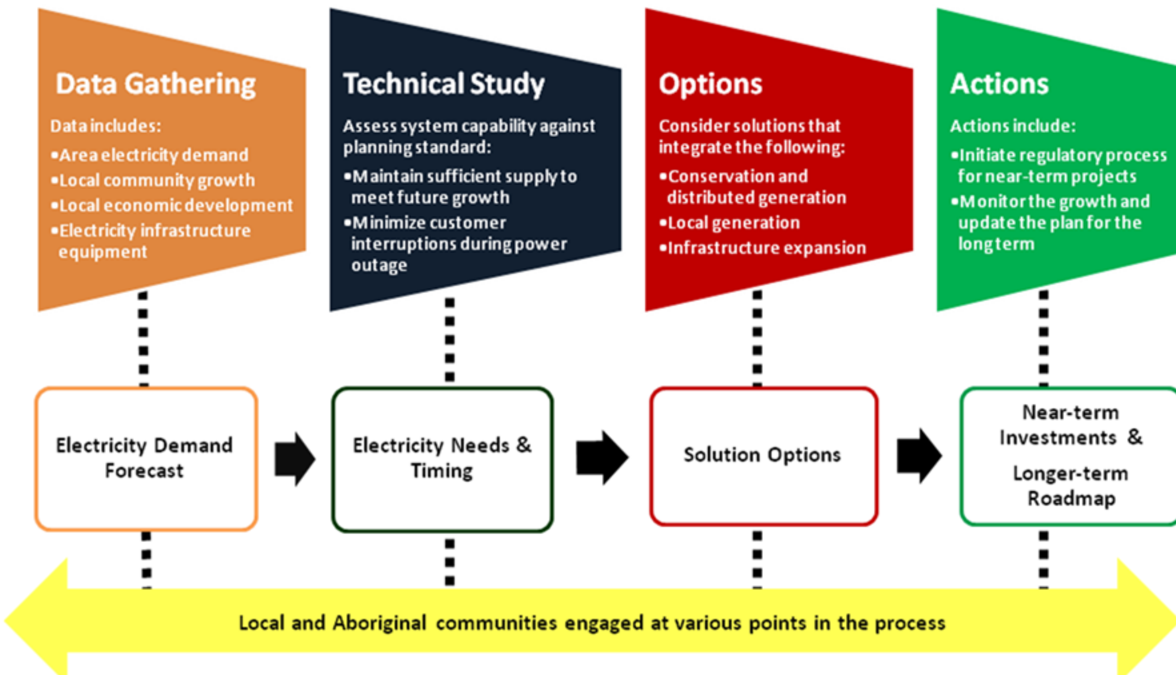
[2] In some cases, such as in this IRRP, the planning assessment was based on a 25-year forecast to account for longer-term growth potential and/or municipal plans. As planning for Central Toronto was initiated in 2011, the forecast period extends to 2036.

responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process to develop those options. Other actions may involve development of conservation, local generation, or other solutions, community engagement, or information gathering to support future iterations of the regional planning process in the Region.

Figure 3-2: Steps in the IRRP Process



3.3 Central Toronto Working Group and IRRP Development

The Central Toronto IRRP process was commenced in 2011 by the Ontario Power Authority ("OPA"), in response to the significant rate of growth of new buildings and urban intensification in the downtown core and other areas within the central part of the city. It had been almost five years since the previous planning study for the area was done for the 2007 Integrated Power System Plan. The OPA proposed that a joint integrated planning study be undertaken which led to the establishment of the Working Group which as noted above included representatives of the former OPA, IESO, Toronto Hydro, and Hydro One.

The OPA developed a Terms of Reference that were signed by each of the participating organizations.[3] The Working Group gathered data, identified near term and potential long-term needs in the area, and recommended the near-term plan included in this IRRP. Implementation of elements of the near-term plan began in 2014 with the OPA issuing letters supporting near-term projects so that they could commence immediately in order to be in-service in time to address imminent needs.

This Central Toronto IRRP is therefore a "transitional" IRRP in that it began prior to the development of the OEB's regional planning process and much of the work was completed before the new process and its requirements were known. When the Regional Planning process was formalized by the OEB in 2013, the planning approach was adjusted to comply with the elements of the new process. This included the incorporation of formal input from electricity consumer groups in the city, municipal planners, other governments groups interested in electricity planning, industry stakeholders and interested community participants. This IRRP reflects this revised and updated information.

[3] The IRRP Terms of Reference can be found on the IESO website: http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/Central-Toronto-IRRP-Terms-of-Reference.pdf

4. Background and Study Scope

The City of Toronto ("City"), the largest city in Canada by population and employment, has a very high land-use density of commercial and residential buildings, especially in the central parts of the city. Toronto is the largest electricity demand centre in Canada, at about 5,000 MW of peak summertime electricity demand, 40% of which (about 2,000 MW) is in the central area.[4] Extensive high density residential and commercial urban redevelopment has contributed to steady electricity demand growth in localized pockets, although the overall City of Toronto demand has been steady at around 5,000 MW for the last 10 years. This pace of growth in localized areas is expected to continue for the next several years. In recent years, more tall buildings have been under construction in Toronto than in any other major city in North America.[5]

To set the context for this IRRP, the scope of the IRRP and the existing electricity system serving the area are described in Section 4.1, and a summary of recent investments in the local electricity system is presented in Section 4.2.

4.1 Study Scope

The IRRP study area is shown in green shading in Figure 4-1. The study area is roughly bounded by Highway 401 to the north, Highway 427 and Etobicoke Creek to the west, Victoria Park Avenue to the east and Lake Ontario to the south. Most of this area operates at the 115 kV transmission level, whereas the surrounding Metro Toronto area is served at the 230 kV level. At the distribution level, most of the area operates at 13.8 kV, while the surrounding area is served by distribution at the 27.6 kV level.[6]

The 230 kV corridors supplying the two main 230kV/115kV transformer stations ("TS") in the east and the west are included within the scope of this IRRP. The individual supply stations along the 230 kV corridor in the east were included in the Metro Toronto Northern sub-region Needs Screening assessment completed by Hydro One in 2014.

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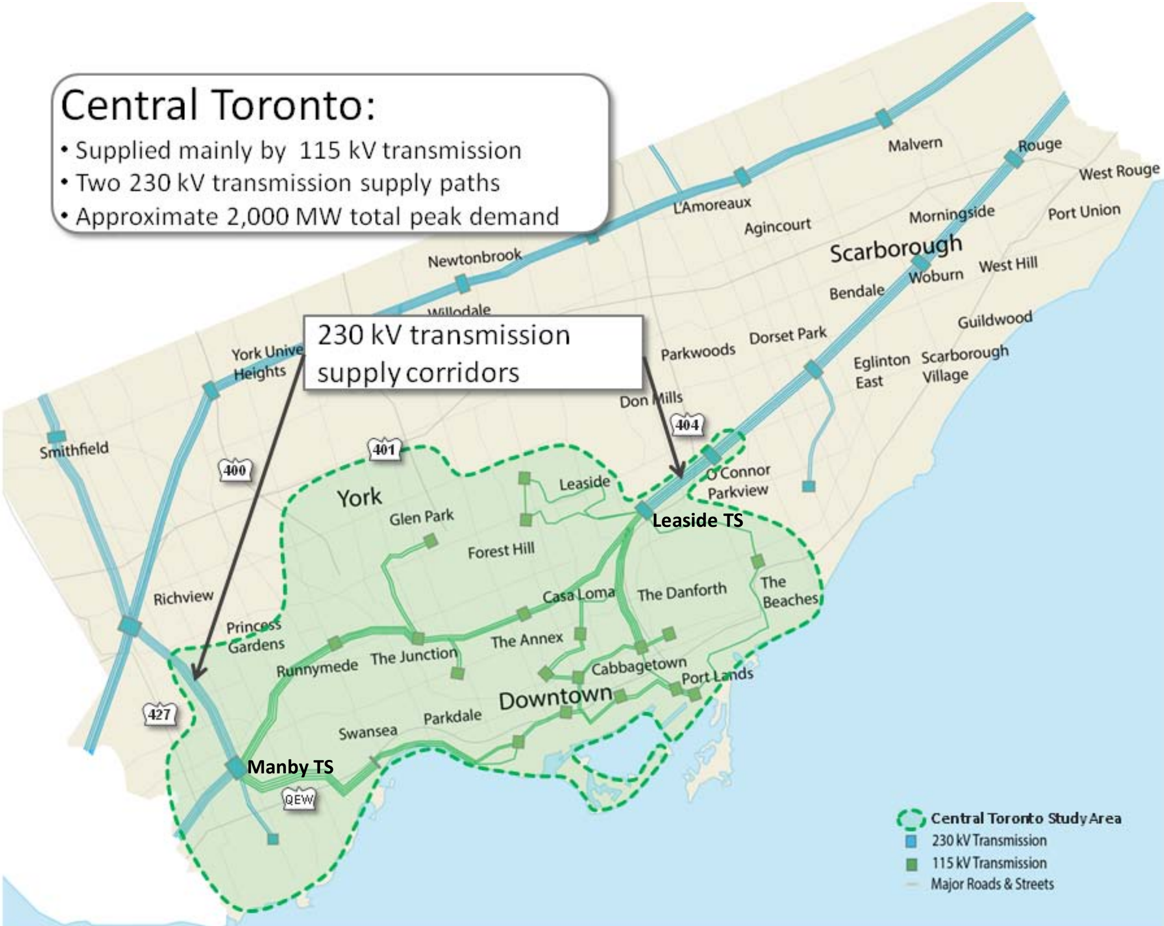
[4] The central area includes the downtown central business area.

[5] There are starting to be some signs of a slow-down in the construction of condominium buildings in Toronto, however, at least 55 tall buildings remain under construction, with many more approved by the City of Toronto for construction. Therefore, despite the possibility of a slower pace of growth in the future, electricity system infrastructure will still be required in the near term to supply the growth that is known with more certainty.

[6] Exceptions in the Central Toronto Area include four transformer stations in the study area that supply distribution system voltages at 27.6 kV. These stations include Manby, Leaside, Runnymede, Fairbank, and Horner transformer stations. These stations are shown in Appendix B.

Figure 4-1: Central Toronto IRRP Study Area



1. The study area boundaries, as shown, are the approximate service areas of the transmission and distribution facilities within the scope of the Central Toronto IRRP.
2. The study area also includes the service areas of Manby TS, Leaside TS and Horner TS, which are supplied by 230 kV transmission.

As shown in Figure 4-2, customers in the study area are served by two main electrical sectors, an eastern sector ("Eastern Sector") and a western sector ("Western Sector"). The Eastern Sector is supplied through a major 230 kV/115 kV TS in the Leaside area (Leaside TS) and the Western Sector is supplied through a major station near Islington City Centre – West in Etobicoke (Manby TS). The Portlands Energy Centre (PEC), a 550 MW natural gas fired combined cycle power plant near the downtown core, also feeds into the Eastern Sector. About 70% of the peak electrical demand (1,400 MW) is normally served by the power system facilities in the Eastern Sector and the remaining 30% of the peak electrical demand (600 MW) is normally served by the power system facilities in the Western Sector. The Western Sector is supplied by two independent busses at Manby TS: Manby West which supplies areas of the downtown core, and

Manby East which supplies areas to the northwest of downtown. A detailed diagram of the transmission system supplying the Central Toronto Area is provided in Appendix A. Further information about the electrical system in the study area can be found within a Central Toronto IRRP Discussion Workbook, available on the IESO website.[7]

Figure 4-2: Electrical Supply in Central Toronto by Sub-sector

Horner TS, to the south of Manby TS, is supplied by 230 kV facilities from Manby TS and is therefore inside the Central Toronto IRRP study area.

The transmission system in the study area has the capability of switching electrical demand between the Eastern and Western Sectors. There are switching facilities and cables that allow some of the load to be transferred back and forth between the Manby East and Leaside systems,

[7] The Discussion Workbook is available at: http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/Central%20Toronto%20IRRP%20-%20Discussion%20Workbook.pdf

and between Manby West and Leaside systems, when required to maintain load supply during equipment outages or system emergencies.

In the event of a loss of supply in the Eastern (Leaside) Sector, the generation source at PEC will be initially lost. While PEC does not have black-start capability,[8] there is sufficient flexibility within the transmission system to restore generation at PEC from the West via switching, when emergencies occur in the Eastern Sector. Restarting PEC from the West is estimated to take about 1 hour to complete.[9]

The flexibility and redundancy built into the transmission system has enabled effective restoration of customers within the city under past extreme failure events. This flexibility also enables planned outages for routine maintenance and major refurbishments without materially impacting service to customers.

Transfer capability at the distribution system level is more limited. Some transfer capability is feasible from bus to bus within stations, but there is very little capability to transfer electrical demand between stations in the Central Toronto Area via the 13.8 kV distribution system.[10] This is a result of the legacy design of the distribution system that was originally built in Toronto.

4.2 Recent, Planned and Committed Resources

Since 2006, numerous projects, programs and initiatives in Central Toronto have addressed supply capacity, reliability, and equipment end-of-life. This has produced lasting improvements to the electricity supply situation in the area. These resources include conservation, local and distributed generation, and transmission and distribution investments.

4.2.1 Conservation

Considerable achievements in electricity conservation have been made in the City of Toronto. From 2006 through 2013, about 295 MW of peak demand reduction has been achieved in the

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[8] Black-start is the capability to restore a power station to operation without relying on the external electric power transmission network, which is normally provided from the station's own generators.

[9] This time can vary depending on the sequence of events that had led to the initial isolation of the Leaside bus.

[10] Recent system investments will provide significant enhancements to the transfer capability in Central Toronto once in service. For example, the Midtown Reinforcement project will permit nearly all of the Manby East demand to be supplied via Leaside TS, and Clare R. Copeland TS, currently under construction in downtown Toronto, will eventually have the ability to transfer load to and from the other major stations around it.

city through programs and initiatives delivered by the OPA, Toronto Hydro and other participants, including the City of Toronto. Much of these savings are expected to persist for the next several years, although savings from conservation committed in the past may diminish over time.

The approach to conservation resource procurement that was taken up to 2015, involved designing and delivering conservation programs to customers province-wide. These programs were evaluated through the OPA's evaluation, measurement and verification (EM&V) process to determine both the provincial and LDC-specific impact of each program. The capability to conduct LDC-specific evaluation of savings for the conservation programs evolved with the ramping up of program offerings in the market. Impacts of conservation efforts were reported both at the provincial and LDC-level.

With the transition to more locally designed conservation programs (through the LDCs, for example), it is expected that conservation programs will be tailored to the local customer base, target specific customer groups in local or regional areas of need, and that results will be directly attributable to the local step-down station or bus level.

2006-2014 OPA Conservation Programs

At least 28 conservation programs were offered in the City of Toronto from 2006 to 2014. Eleven of these programs continue to be offered as the province transitions to the new conservation framework and Toronto Hydro's 2015-2020 Conservation Plans are implemented. Moving forward, under the Conservation First Framework, all Ontario LDCs are required to produce a conservation and demand management plan by May 1st, 2015 outlining how they intend to meet their mandated energy savings targets within their allocated conservation budget from 2015 to 2020.

The programs that have been offered to customers in Toronto are listed in Table 4-1. These are mostly province-wide programs delivered by Toronto Hydro or various delivery channel partners. Some initiatives were rolled out as pilots, and learnings from these initiatives were integrated into future programs or program redesign.

Table 4-1: 2006-2014 Conservation Programs in the City of Toronto

Program	Market Sector	Availability
Affordable Housing Pilot	Residential Low Income	2007
Cool & Hot Savings Rebate	Residential	2006-2010
Demand Response 1	Commercial & Institutional, Industrial	2006-2009
Demand Response 2	Commercial & Institutional, Industrial	2009-2010
Demand Response 3	Commercial & Institutional, Industrial	2008-Current
Energy Efficiency Assistance Pilot	Residential Low Income	2007
Every Kilowatt Counts	Residential	2006-2010
Great Refrigerator Roundup	Residential	2006-2010
High Performance New Construction	Commercial & Institutional	2008-Current
Toronto Hydro - Summer Challenge	Residential	2009
Loblaws Demand Response	Commercial & Institutional (Loblaw)	2006-2010
Multi-Family Energy Efficiency Rebates	Residential, Residential Low Income	2009-Current
peaksaver® and ***peaksaver* Plus**®	Residential, Business	2007-Current
Power Savings Blitz	Commercial & Institutional	2008-2010
Social Housing Pilot	Residential Low Income	2007
Summer Savings	Residential	2007
Summer Sweepstakes	Residential	2008
Toronto Hydro Comprehensive	Residential, Commercial & Institutional, Residential Low-Income	2007-2010
Appliance Exchange	Residential	2011-Current
Appliance Retirement	Residential	2011-Current
Residential Coupons (Annual and Event Coupons)	Residential	2011-Current
HVAC Incentives	Residential	2011-Current
Retailer Co-op	Residential	2011-Current
Direct Install Lighting	Commercial & Institutional	2011-Current
Retrofit	Commercial & Institutional	2011-Current
Energy Audit	Commercial & Institutional	2011-Current
Home Assistance Program	Residential	2011-Current
Energy Manager	Industrial	2011-Current

City of Toronto Energy Saving Policies and Programs

In addition to the conservation programs listed in the preceding section, the City of Toronto has developed a number of innovative policies and programs that conserve energy. A summary of these policies and programs is presented in Table 4-2. This summary has been adapted from the City of Toronto Energy & Emissions Inventory and Mapping Report (2013).

Table 4-2: City of Toronto Energy Saving Policies and Programs

Policy	Description	Target Group
City Wide Energy Policies		
Toronto Green Standard (TGS)	The TGS is a two-tiered set of performance measures and guidelines used to achieve sustainable site and building design in new developments. New buildings are required to achieve a minimum energy performance of 25% better than the Model National Energy Code for Buildings/Ontario Building Code within Tier 1, and a voluntary energy performance of 35% energy savings within Tier 2. These minimum and voluntary targets are currently under review and are expected to increase in the future.	New planning applications (including Zoning By-law Amendment, Site Plan Control and Draft Plan of Subdivision) are required to comply with Tier 1 standards. Tier 2 measures are voluntary and applicants who wish to meet them may be eligible for a Development Charge Rebate.
Green Roof By-law	Sets green roof and cool roof coverage requirements for new developments as a way to reduce storm water runoff and building cooling demand.	Applies to new building permit applications for residential, commercial and institutional development made after January 31, 2010 with a minimum gross floor area (GFA) of 2,000 m2
Area Specific Energy Policies		
Waterfront Toronto Minimum Green Building Requirements	Waterfront Toronto Minimum Green Building Requirements	Waterfront Toronto Minimum Green Building Requirements
Secondary Plan Requirements for Energy Studies	Secondary Plan Requirements for Energy Studies	Secondary Plan Requirements for Energy Studies
Energy Programs		
Better Building Partnership	Better Building Partnership	Better Building Partnership
Home Energy Load Program	Home Energy Load Program	Home Energy Load Program

Conservation Pilot Initiatives in the City of Toronto

In addition, a number of innovative conservation pilot initiatives have either been completed or are underway in the City of Toronto. The IESO, Toronto Hydro, and the City of Toronto pilot initiatives are summarized in Table 4-3. Opportunities to scale these pilots to programs are being evaluated.

Table 4-3: Conservation Pilot Initiatives in the City of Toronto

Pilot	Description	Savings Opportunity
Pay for Performance (PFP): $/kWh (Loblaws Inc.)	• Pilot initiated in 2014 • Pay for Performance is a financial model in which savings from energy efficiency upgrades receive additional monetary compensation (beyond reduced operating costs) • If energy consumption increases penalties may be applied • Contracts may be offered in targeted areas	• To be evaluated
Municipal financial support through Local Improvement Charges (City of Toronto)	• Pilot initiated in 2014 • Local Improvement Charges (charged and collected by the city) will be used to create a fund, which will be available as a low-interest loan to individuals for investment in energy efficient upgrades • Pilot will include 200 homes and 200 apartment units • The City expects to make the fund available to all Toronto residents by 2015	• Maximum energy efficiency upgrades is expected to be 10% per building/unit
Multi-unit residential building demand response pilot (MURB DR) (Toronto Hydro)	• Pilot initiated in 2013 • Involves the installation of load control devices and programmable communicating thermostats in MURB units and common areas • Energy efficiency retrofits will also be conducted in building common areas	• Involves four condominium facilities for a total of 400 suites; the anticipated savings is 0.3 kW per suite and 77.9 kW per common area (with 100 suites, per building savings is 101 kW (ca. 10% of load) • A total of 20MW of demand reduction may be achieved if full program launch is enabled (ca. 200 buildings)
Local Demand Management Pilot Study (Toronto Hydro)	• Study initiated in fall 2013 • Aim is to assess the estimated demand savings from targeted demand reduction initiatives and to design and run pilots in constrained service areas	• If the initiative achieved 5% in demand savings, infrastructure investments could be offset for several years
Commercial Energy Management and Load Control (CEMLC) pilot (Toronto Hydro)	• Pilot involves the installation of load control devices and programmable communicating thermostats to be activated during peaksaver PLUS activation periods	• Pilot initiated in 2013 for the 50-250 kW commercial sector • Involves 12 facilities (3 in each of the office, retail, hospitality and institutional sectors); the average demand savings per site is expected to be 23.4 kW (280 kW total) • A total of 42 MW of demand reduction may be achieved if full program launch is enabled (1,800 sites)
HVAC load shifting technology pilot (Ice Energy- Ice Bear Energy Storage System)	• Piloted by Toronto Hydro 2010-2011 (supported by the OPA)	• Each unit reduces peak demand by 12 kW

Deep Lake Water Cooling

Downtown Toronto is home to the Deep Lake Water Cooling System that provides air conditioning to commercial, institutional, government and residential buildings by drawing cool lake water and circulating it to buildings to replace the need for electric air conditioning systems. It is estimated that deep lake water reduces electricity usage by 90% compared to conventional cooling systems. The Deep Lake Water Cooling System has been estimated to have reduced the downtown peak demand by as much as 61 MW.

4.2.2 Generation Resources

Since 2008, a number of new generation facilities have been installed in Central Toronto. The Portlands Energy Centre ("PEC") is an example of a large transmission connected generation facility sited within the load centre. Many new small renewable generation facilities have also come into service under the province's Feed-in Tariff program, as well as combined heat and power projects. These facilities are described further below.

Portlands Energy Centre 550 MW Gas-fired Generating Station

Phased in from 2008 to 2009, a major new generation supply resource was placed in-service and connected at the Hearn switching station in the Portlands area. This 550 MW combined cycle generation facility is an important source of generation providing capacity and supply security within the Central Toronto load area. The PEC restored some balance to the supply and demand situation in downtown Toronto, which had become imbalanced when the Hearn generating station was decommissioned in the 1980s.

Renewable Energy Generation

Since 2009, 13.75 MW of new renewable energy generation facilities have been contracted for in Central Toronto under the Feed-in Tariff program. Of these 120 projects, 13 MW are rooftop solar photovoltaic ("PV") projects, and one project is the 750 kW wind turbine installed at Exhibition Place. Another 731 microFIT solar PV projects, totaling approximately 4 MW of capacity, have been contracted for across the City of Toronto, a portion of which are located in the Central Toronto Area.

District Energy

The City of Toronto has identified and studied 27 areas, or "nodes," throughout the city where the density of development provides an opportunity to develop District Energy systems.[11] Of these 27 nodes, 10 were identified as having high potential to be developed, 7 of which are within the Central Toronto Area:

- East Bay Front (Jarvis and Queens Quay)
- Yonge and Dundas
- Yonge and Bloor
- West Don Lands (Eastern and Front)
- Fort York (Bathurst and Lakeshore)
- Etobicoke Civic Complex (West Mall and Civic Center Court)
- Lawrence Phase 2 (Allen and Lawrence)

A 1.6 MW District Energy system is currently under construction at Exhibition Place. Electrical energy generated will help meet local peak electricity demand needs of the area, and thermal energy will be sold to a new hotel under construction on the Exhibition Place grounds.

Other small District Energy systems in the City of Toronto make up a portion of the 21.5 MW of reliable peak electricity demand reduction that represents the full complement of DG resources within the Central Toronto Area.[12]

4.2.3 Transmission and Distribution Facilities

Since 2007, numerous transmission and distribution projects have been started or completed to address supply capability, reliability or equipment end-of-life issues in the Central Toronto Area. These projects include:

- John TS to Esplanade TS underground cables
- Midtown 115 kV transmission reinforcement
- Hearn switching station rebuild
- Breaker upgrades
- Lakeshore 115 kV cable refurbishment
- Clare R. Copeland 115 kV transformer station

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[11] Report is available for download at the City of Toronto website: http://www1.toronto.ca/City%20Of%20Toronto/Environment%20and%20Energy/Programs%20for%20Businesses/BBP/PDFs/FINAL-GENIVAR-Report-City-of-Toronto-District-Energy-November-21-13.pdf

[12] 21.5 MW is the capacity of DG resources that can predictably generate during the peak demand period.

Many of these projects stemmed from previous integrated planning studies completed since the mid-1990s, and are discussed in more detail below. Over the last 10 years, investment in Central Toronto's electricity system has been approximately $1.3 billion.

John TS to Esplanade TS Underground Cables

Two new underground cables, 2.2 km in length, from the John TS to Esplanade TS were placed in-service in 2008 by Hydro One. These cables resulted in enhanced reliability and security between the Leaside and Manby systems and addressed the need for increased load transfer capability between the two 115 kV systems. This link was recognized as a common facility required for a future major new transmission supply to Central Toronto. The cables are capable of operation at 230 kV, but are currently being operated at 115 kV.

Midtown 115 kV Transmission Reinforcement

The Midtown transmission project, currently underway, is a multi-stage transmission refurbishment project that is replacing the underground cables between Bayview Junction and Birch Junction in the Leaside TS sector. This joint Hydro One – Toronto Hydro project will add a new 115 kV circuit between Leaside TS and Birch Junction, as well as installing new equipment at Leaside TS and the Bayview, Birch and Bridgman Junctions to provide additional electrical supply capacity to the area. In addition to addressing capacity issues for supplying Bridgman TS and Dufferin TS, the project provides additional capacity to transfer the Wiltshire TS load from the Manby TS sector to the Leaside TS sector under most normal operating conditions. This will provide more flexibility to address loading or equipment issues not only on the Manby TS system but also further upstream in the western parts of the GTA. This line upgrade will also enable nearly all of the electrical demand in the Manby East system to be supplied from Leaside TS under emergency conditions (up to 340 MW).

Hearn Switching Station Rebuild

Hydro One has completed a full rebuild of the Hearn switchyard in the Portlands area to address equipment end-of-life at this important switching station in downtown Toronto. The new Hearn station permits the Hearn 115 kV switchyard to operate as one bus rather than in split bus configuration, resulting in improved overall balancing of electrical demand on the transmission facilities out of Leaside TS.

Breaker Upgrades

Hydro One has replaced the 115 kV circuit breakers at both Leaside TS and Manby TS. These projects have resulted in the removal of fault current limitations that had affected the downtown area. They will also permit the connection of additional DG in the Central Toronto Area. In addition, the new equipment is more reliable and reduces the probability of an unexpected breaker failure contingency affecting supply to customers in the area.

Lakeshore 115 kV Cable Refurbishment

The Lakeshore Renewal Project is the second phase of the Lakeshore sustainment project first undertaken in the 1990s. The current project by Hydro One involves replacement of two 115 kV underground cables connecting Riverside Junction at Windermere Avenue and Lakeshore Boulevard to Strachan TS at Strachan Avenue and Manitoba Drive. Hydro One is installing two new 230 kV cables, but the cables will operate at 115 kV until more power is needed. The existing cables that were originally installed in the late 1950s will be decommissioned once the new cables are in service. The typical lifespan of a cable is 50 to 60 years.

Clare R. Copeland 115 kV Transformer Station (Phase 1)

Toronto Hydro is building the first new step-down transformer station in downtown Toronto in many years. In addition to providing additional supply capacity in the heart of the downtown business district, the Clare R. Copeland TS ("Copeland TS," formerly called Bremner TS) will provide additional flexibility to transfer downtown loads from Manby to Leaside and this additional load-shifting capability can reduce the amount of load at risk of being interrupted in the event of a contingency at Manby TS or John TS.

5. Demand Forecast

This section outlines the demand forecast for Central Toronto. The demand forecast estimates the future peak electricity demand within the area over the planning horizon, including the contribution of conservation and DG to reducing peak electricity demand requirements.

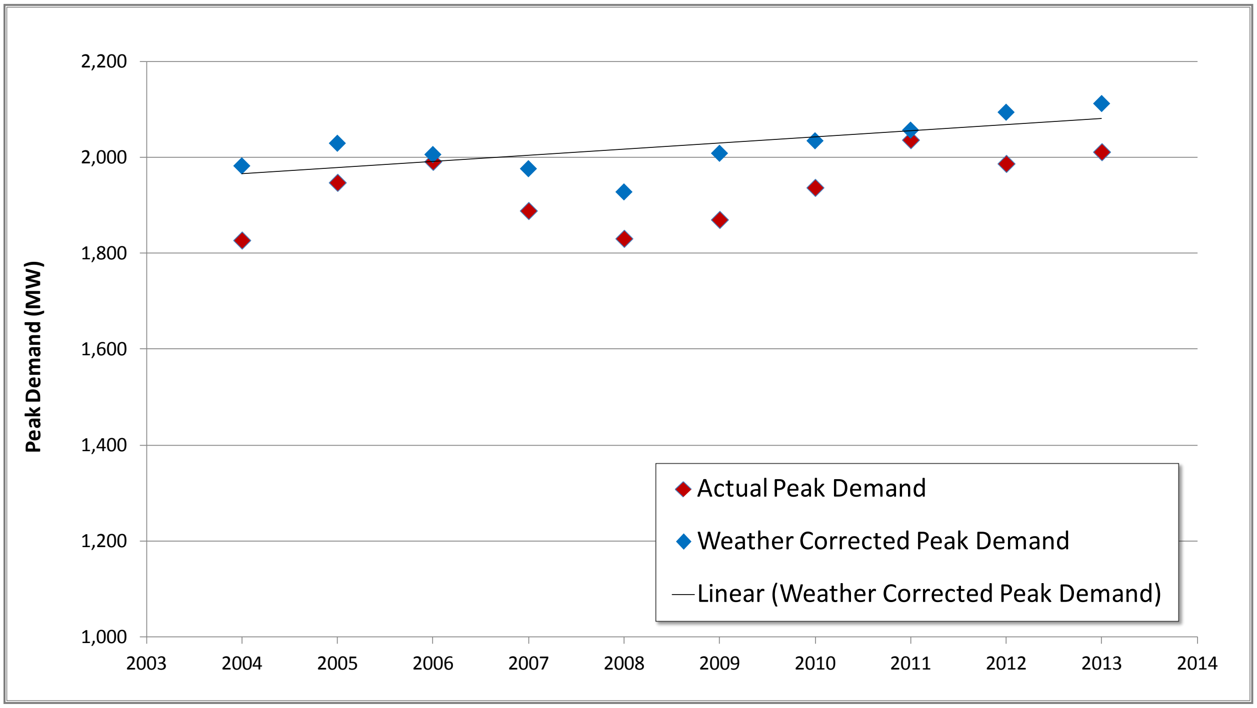
For the purposes of evaluating the adequacy of the electricity system, regional planning is concerned with the regional coincident peak demand. Coincident peak demand is the demand observed at the transformer stations for the hour of the year when overall demand in the study area is at its highest. This represents the moment when equipment is expected to be the most stressed, and resources the most constrained. Within Central Toronto, the peak loading hour for each year typically occurs in mid-afternoon of the hottest weekday during the summer, and is driven primarily by the weather sensitive air conditioning loads of commercial and residential customers. Within the past 10 years, the local peak occurred on the same day as the overall provincial peak in each year but one.

The following sections describe the historical demand trends in the area, followed by a description of the various forecast elements, including the gross forecast, conservation forecasts, and the net forecasts used for determining the electricity service requirements for the plan.

5.1 Historical Demand

Over the past five years, Central Toronto has experienced moderate overall growth in electricity demand. In 2007 and 2008, a decrease in electricity demand in the Central Toronto Area occurred, as conservation programs entered the market and the economy experienced a downturn. Since 2008, the demand in the area has returned to pre-recession levels and has been buoyed by strong growth in new building construction. Historical peak demand has averaged growth of 0.7% per year over the past decade, as shown in Figure 5-1.

Figure 5-1: Historical Electricity Peak Demand for Central Toronto 115 kV System



Within Central Toronto, there have been individual pockets of higher growth, and some areas that have experienced lower growth. In particular, the downtown core, consisting of five transformer stations (Cecil TS, Terauley TS, Esplanade TS, John TS and Strachan TS), has averaged growth of 1.2% per year over the same time period.

Factors that have influenced the historic peak demand from 2006 onwards have been the savings associated with conservation programs, and other initiatives such as the Deep Lake Water Cooling System Project that has been estimated to reduce the downtown peak demand by as much as 61 MW.

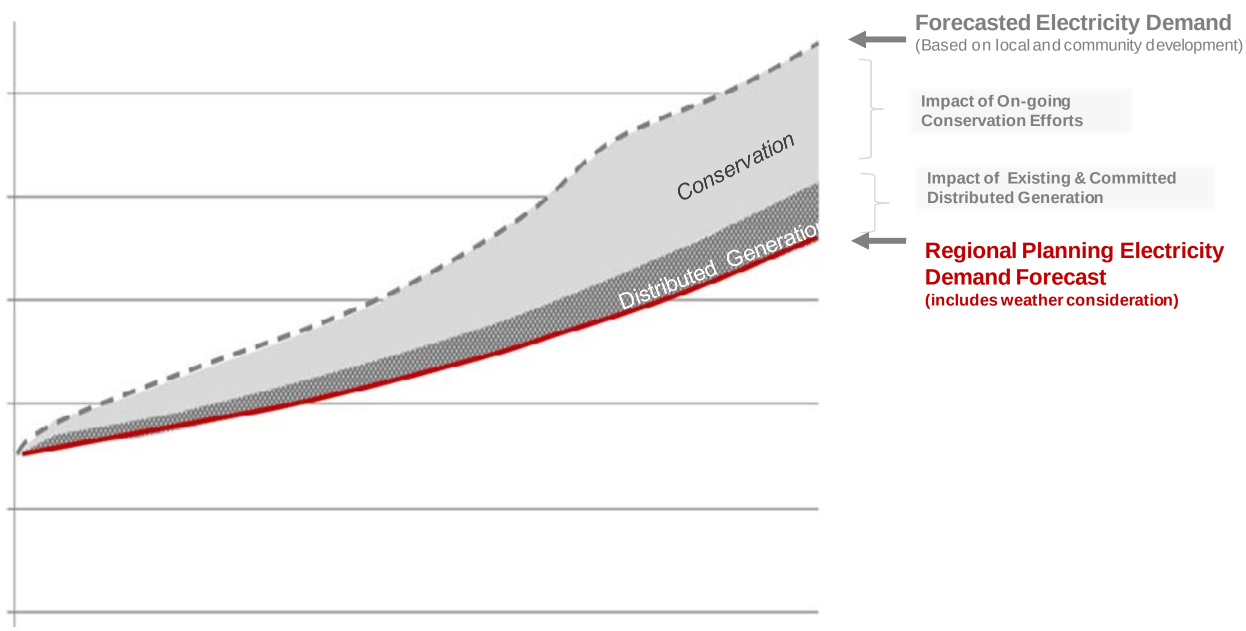
5.2 Demand Forecast Methodology

Regional electricity needs are driven by the limits of the infrastructure supplying an area, which is sized to meet peak demand requirements. Therefore, regional planning typically focuses on growth in regional-coincident peak demand. The Toronto region is a summer peaking area. The adequate supply of electricity, or energy adequacy, is usually not a concern, as the region can generally draw upon energy available from the provincial electricity grid and provincial energy adequacy for the province is planned through a separate process.

A regional peak demand forecast was developed as illustrated in Figure 5-2. A gross demand forecast, assuming extreme-weather conditions, was provided by Toronto Hydro. The gross demand forecast accounted for the growth projections provided by City of Toronto plans and projections for population, economic development, and intensification through plans for new building and urban development, and considered the impact of existing in-market conservation programs and existing DG. This forecast was then modified to reflect the peak demand impacts of future provincial conservation targets to produce a planning forecast. The planning forecast was then used to assess any growth-related electricity needs in the region.

Using a planning forecast that is net of provincial conservation targets is consistent with the Province's Conservation First policy. However, this planning forecast assumes that the energy targets will be met, and will produce the expected local peak demand impacts. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by Toronto Hydro, and as necessary, revisiting and adapting the plan if assumptions change.

Figure 5-2: Development of Demand Forecasts



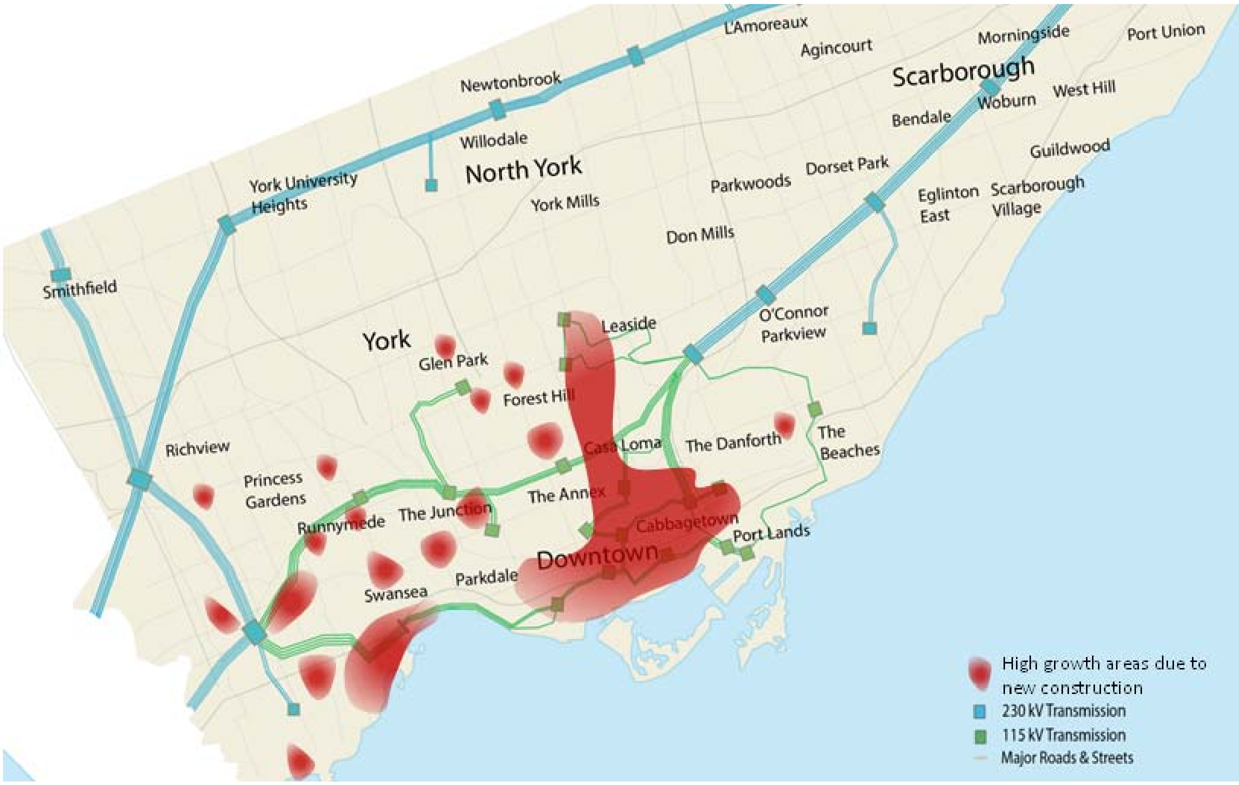
5.3 Gross Demand Forecast

For the purpose of this study, Toronto Hydro commissioned Navigant Consulting Inc. to develop a summer peak demand forecast covering a 25-year planning horizon. The forecast accounts for information on developments expected to contribute to demand growth in the area, including population and employment. The forecast provided by THESL was developed under coincident, extreme-weather assumptions, which accounts for the weather sensitive aspects of electricity demand such as space cooling in the summer months. Further detail about the methodology used to develop Toronto Hydro's gross forecast is provided in Appendix B.[13]

Overall, growth is expected to continue over much of the Central Toronto Area. The majority of growth is expected to be concentrated where significant pockets of new development are occurring, such as the central lakeshore area and the west end of the City. The growth in these areas is primarily due to high rise building development, and is shown in Figure 5-3.

[13] It is noted that Navigant produced separate forecasts termed "gross" and "net." The "gross" forecast excludes all conservation and DG past, present and future, and represents a forecast absent the impact of any conservation measures implemented in Toronto since 2006. This forecast is less useful for the purpose of determining electricity system needs. The "net" forecast includes historical conservation and the current conservation programs that were in-market in 2012 until 2014. After 2014, the THESL "net" forecast does not account for additional conservation programming. The references to THESL's "gross" demand forecast in this document actually refer to the "net" forecast as described in Appendix B.

Figure 5-3: Concentrations of Growth in Central Toronto



Source: City of Toronto

5.4 Conservation Resources Assumed in the Forecast

Conservation plays a key role in maximizing the useful life of existing infrastructure, and maintaining reliable supply. Conservation is achieved through a mix of program-related activities, including behavioral changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results. The conservation savings forecasts for Central Toronto have been applied to the gross peak demand forecast, along with existing DG resources, to determine the net peak demand for the region.

In December 2013 the Ministry of Energy released a revised Long-Term Energy Plan (LTEP), which outlined a provincial conservation target of 30 TWh of energy savings by 2032. To represent the effect of provincial targets within regional planning, the IESO developed forecast scenarios for peak demand savings based on varying levels of achievement of the provincial savings target. These conservation scenarios were applied to the gross demand forecast to develop estimates of the peak demand impacts in Central Toronto. The conservation estimates are shown in Table 5-1. Additional conservation forecast details are provided in Appendix C.

Table 5-1: Peak Demand Savings Assumed from the 2013 LTEP Conservation Targets in Central Toronto (Megawatts)

Year	2014	2016	2018	2021	2026	2031	2036
High Demand Scenario	305	253	255	241	215	215	238
Low Demand Scenario	305	346	376	411	497	611	641
Median Demand Scenario	305	253	255	284	366	396	423

5.5 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG is also anticipated to offset peak demand requirements. The introduction of the *Green Energy Act, 2009* ("GEA"), and the associated development of Ontario's Feed-in Tariff ("FIT") program, has increased the significance of distributed renewable generation in Ontario. This generation, while intermittent in nature, contributes to meeting the electricity demands of the province.

In developing the planning forecast, the effects of DG in service at the time were included. Each project's capacity contribution was subtracted from the peak demand at the transformer station to which it was connected. The amount of DG assumed to have a peak demand impact was 21.5 MW.

Future DG uptake was not included in the forecast due to difficulties forecasting the uptake and location. This leaves DG potential as an option for meeting future needs.

Additional details of the demand reductions attributable to DG are provided in Appendix C.

5.6 Planning Forecasts

After taking into consideration the combined impacts of conservation and DG, planning forecast scenarios were produced based on the demand forecast submitted by Toronto Hydro to the Working Group.

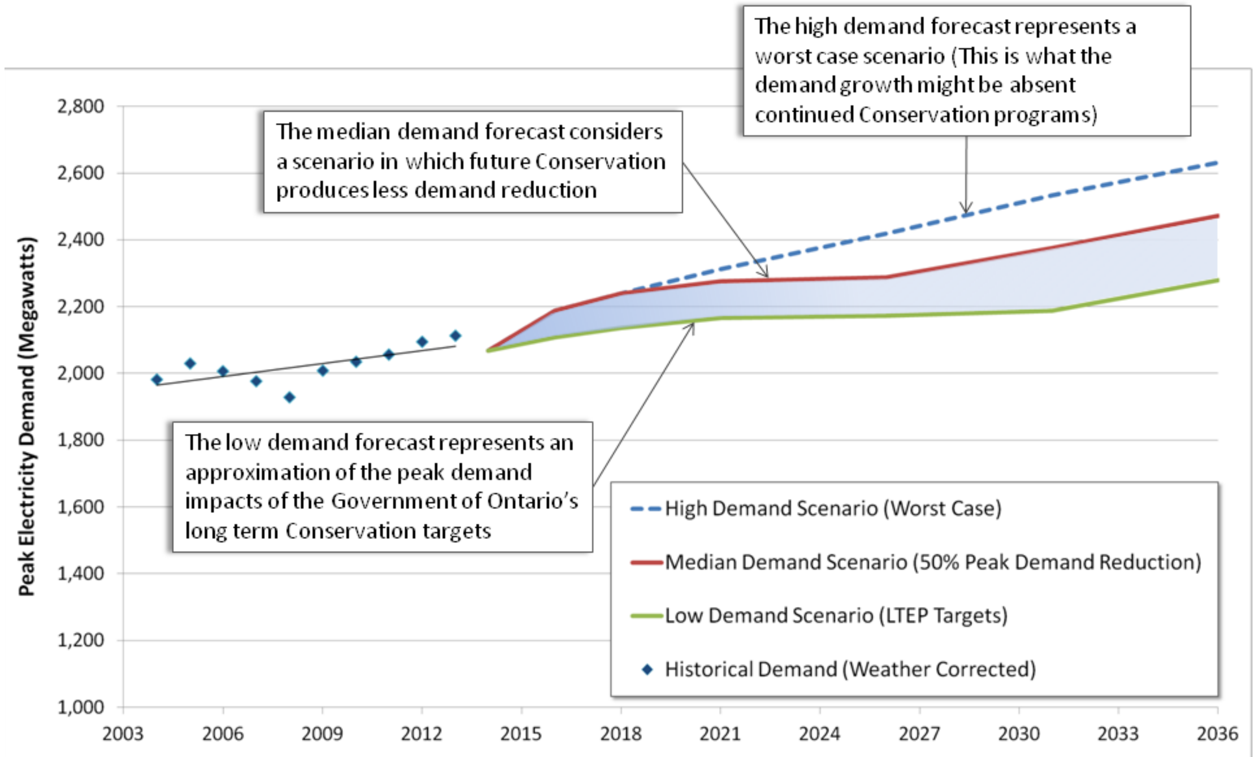
A "high demand" growth scenario was assessed to determine what the system needs would be under a worst-case, in which either conservation does not meet expectations, or new growth and development accelerate in the area. This forecast scenario assumes 238 MW of savings from conservation targets across the Central Toronto Area over the next 25 years. This scenario assumes that all historic and conservation initiatives to the end of 2014 continue to provide persistent savings, but no new conservation after 2015. The average annual growth rate under this scenario is 0.99% per year.

A "low demand" growth scenario was assessed which assumes that 60% of the new demand growth will be met through future conservation programs. The basis for this scenario was the provincial Long-Term Energy Plan targets ("LTEP targets"). This forecast scenario assumes 641 MW of new savings from conservation targets across the Central Toronto Area over the next 25 years. Combined with the effects of DG and existing conservation programs, the low demand scenario forecast assumes that the impact of future conservation programs to meet the long-term targets will reduce the average annual growth rate from 0.99% to 0.38% growth per year.

An additional planning scenario was developed to reflect the uncertainty associated with forecasting electricity demand and the possibility of varying levels of peak demand impact from future conservation. This "median demand" scenario was developed to test the impact on system needs if either future conservation produces less peak demand impact, or new customer growth is higher than forecast. This forecast scenario assumes 423 MW of new savings from conservation targets across the Central Toronto Area over the next 25 years, which considers 50% of the peak demand reduction compared to the low demand scenario. This represents a growth rate of 0.72% growth per year. This growth rate is closest to the historical rate of electricity demand growth in Central Toronto over the last ten years (0.71%).

The three demand scenarios are shown in Figure 5-4 for the 115 kV transmission system in Central Toronto. The raw demand forecast data for the entire study area is provided in Appendix D.

Figure 5-4: Electricity Peak Demand Forecast for Central Toronto (115 kV System)



6. Needs

This study assessed the capability of the existing high voltage power system to provide reliable electrical service over the near-term (0-5 years), medium-term (6-10 years) and longer-term (11-25 years) periods.[14] The assessment accounted for growth in electrical demand within the study area, the reliability standards established for power systems within Ontario, service quality expectations as expressed by customers, and other preferences indicated by the local community through the engagement process. The assessment as noted, also accounted for the implementation of expected conservation, given existing programs that are in the planning phases and targets established by the Province of Ontario.

6.1 Need Assessment Methodology

Provincial planning criteria were applied to assess the capability of the existing electricity system to supply forecast electricity demand growth in the Central Toronto are over the forecast period. Electrical system needs were determined through a series of tests as defined in the ORTAC, which establishes the planning criteria and assumptions to be used for assessing the adequacy and security of Ontario's electricity system.[15]

Technical assessments were conducted using industry-standard software-based modeling tools such as Power System Simulator for Engineering ("PSS®E") for conducting deterministic contingency analysis, and using the probabilistic assessment feature within PSS®E to estimate the risk related to certain contingencies that are beyond the stress tests as defined by the criteria in ORTAC. All system tests were performed assuming summertime peak demand conditions under the various demand forecast scenarios described in Section 5.

6.1.1 Ontario Resource Transmission Assessment Criteria

In accordance with the ORTAC, the transmission system must be able to provide continuous supply following defined transmission and generation outage scenarios, and limit the amount of load loss and restoration time following the occurrence of multiple element outages. The

[14] The long-term planning horizon for a Regional Plan is typically 20 years. In the case of Central Toronto, Toronto Hydro provided a forecast covering a 25-year period. The Working Group agreed to assess needs based on the 25-year forecast.
[15] The ORTAC document can be found on the IESO website:
http://www.ieso.ca/Documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

defined outage scenarios are referred to as "contingencies." These contingency-based tests are deterministic in that they are assessed independent of the probability of their occurrence.

Deterministic assessments are an established electricity industry practice for assessing the power system's ability to supply the demand under various possible states, including:

- all system elements in service (N-0),
- following the loss of any one transmission or generation element (N-1),
- following the loss of any one element while another element is on outage or planned maintenance (N-1-1), and
- In certain cases, following the loss of two elements simultaneously (N-2).[16]

In addition to the deterministic tests, the assessment accounted for the flexibility within ORTAC to rationalize higher (or lower) levels of reliability performance.[17] A probabilistic-based reliability assessment ("PRA") was conducted to test higher-order contingencies beyond those specified in ORTAC. Contingencies involving the loss of up to three independent power system elements (N-3) were tested with consideration of the frequency with which they might be expected to occur and the duration of the outages. The frequency and expected duration of an outage for each element was based on the historic levels of reliability and restoration service within the study area, as reported to the Working Group by Hydro One.

PRA provides an estimation of the amount of energy that is likely to go unsupplied in each year, as expressed by the Expected Unserved Energy ("EUE") metric,[18] giving an indication of "unreliability" related to the system design.

Types of Needs Uncovered in the Assessment

The assessment of the electricity system facilities serving Central Toronto uncovered a number of electricity power system needs. These needs generally fall into the following categories: (1) capacity-based needs relating to providing required infrastructure capacity to supply the peak

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[16] Transmission facilities that provide Local Area supply are tested to N-1, or N-1-1 levels of security, whereas Bulk Power System facilities are tested to N-2 to account for the possible system impacts that could result from double contingencies.

[17] For example, Section 7.4 of ORTAC allows for transmission customers and transmitters to agree on higher or lower levels of reliability for technical, economic, safety and environmental reasons. The IRRP Working Group agreed that in the case of Central Toronto, that the assessment be supplemented by reviewing the impact of higher order contingencies on customers in the area.

[18] The EUE metric does not provide an absolute determination of the amount of energy that will not be supplied due to unreliability of the system. Rather, it is an indicator only and should not be interpreted as an accurate representation.

demand; (2) reliability-based needs relating to reducing the impact of supply interruptions; and (3) security-based needs relating to the ability to restore supply after major contingencies or unusual events such as extreme weather. These types of needs are described further below.

- **Capacity** is the ability to supply peak demand under normal conditions (i.e., all equipment in service) or under a contingency condition (e.g., one or more power system elements out of service). This ability includes the electrical and physical attributes of the power system to carry out its role.
- **Reliability**, in the context of interruptions of electricity supply to customers, involves two considerations. The first relates to the frequency of supply interruptions (or how often they occur). The second relates to the duration of supply interruptions, and the ability of the system to enable the restoration of service to customers within a specified period of time.
- **Security** involves ensuring that the power system is designed with enough flexibility to reasonably contain the interruption of electricity supply to customers when extraordinary failures occur, and to enable the restoration of supply to interrupted customers within a reasonable period of time. Security includes the ability of the system to cope during major events such as storms and other extreme weather events. The coincident or overlapping failure of several pieces of equipment, the failure of an entire transmission station, or more than two transmission circuits are considered as extraordinary failure events. Given the rare nature of these events, the cost of ensuring full redundancy is typically not justifiable. However, these rare failure events are given consideration in planning, as the power system should have the capability to limit the number of customers exposed and restore interrupted customers within a reasonable period of time.

As part of the security assessment, the IESO reviewed the system design under major power system failure events. A few of these events have occurred over the last several years and the Working Group agreed that proactively investigating the susceptibility of the local power system to these events should be a key component of this study. Although the occurrence of these types of failure events is statistically rare, they tend to have very high impacts on customers if the system and related operational procedures are not able to restore power to customers within a reasonable time period.

The needs identified through the assessment are summarized in the following sections for the near-term and medium-term periods and in Section 8 for the long term.

6.2 Near-Term and Medium-Term System Needs

The technical assessment of the electricity system serving Central Toronto uncovered a number of system needs to be addressed by actions in the near term and medium term.

The near-term needs (0 to 5 years) and the medium-term needs (6 to 10 years), and the options and recommended actions for addressing these needs are summarized in Table 6-1 and are shown in Figure 6-1. Further details are provided in the following sections. Technical summaries of the assessment results are provided in Appendix E. Long-term needs and options are discussed in Section 8.

Table 6-1: Summary of Near and Medium-Term Needs in Central Toronto

Need	Description	Timing	Map Reference (Figure 6-1)	Section Reference
Supply security	Breaker failure contingency at Manby West and Manby East	Today at Manby West; 2018 at Manby East	1	6.2.2
Supply security	Breaker failure contingency at Leaside TS	Today	2	6.2.3
New transformation capacity	Demand growth in West Toronto is forecast to exceed the limits of Runnymede TS and Fairbank TS	2018	3	6.2.5
New transformation capacity	Demand growth in Southwest Toronto is forecast to exceed the limits of Manby TS and Horner TS	2018	4	6.2.5
Transmission line capacity	Demand growth in Central Toronto is forecast to exceed the limits of the 230 kV Richview TS to Manby TS corridor	2018	5	6.2.6
New transformation capacity	Demand growth in the downtown core is forecast to exceed the limits of Esplanade TS and Copeland TS	2021	6	6.3.2

Figure 6-1: Map Showing Need Locations in Central Toronto

6.2.1 Improving Supply Security for Low Probability Breaker Failures at Manby TS and Leaside TS

The IRRP assessment identified a need to reduce the impact of multiple element contingencies at the two major transformer stations that provide grid supply to the Central Toronto Area. These needs are related to the potential failure of a switching device (e.g., breaker) to perform the intended function of clearing an electrical fault. Such a failure could result in electricity service interruptions to customers in the Central Toronto Area.

6.2.2 Manby TS Needs

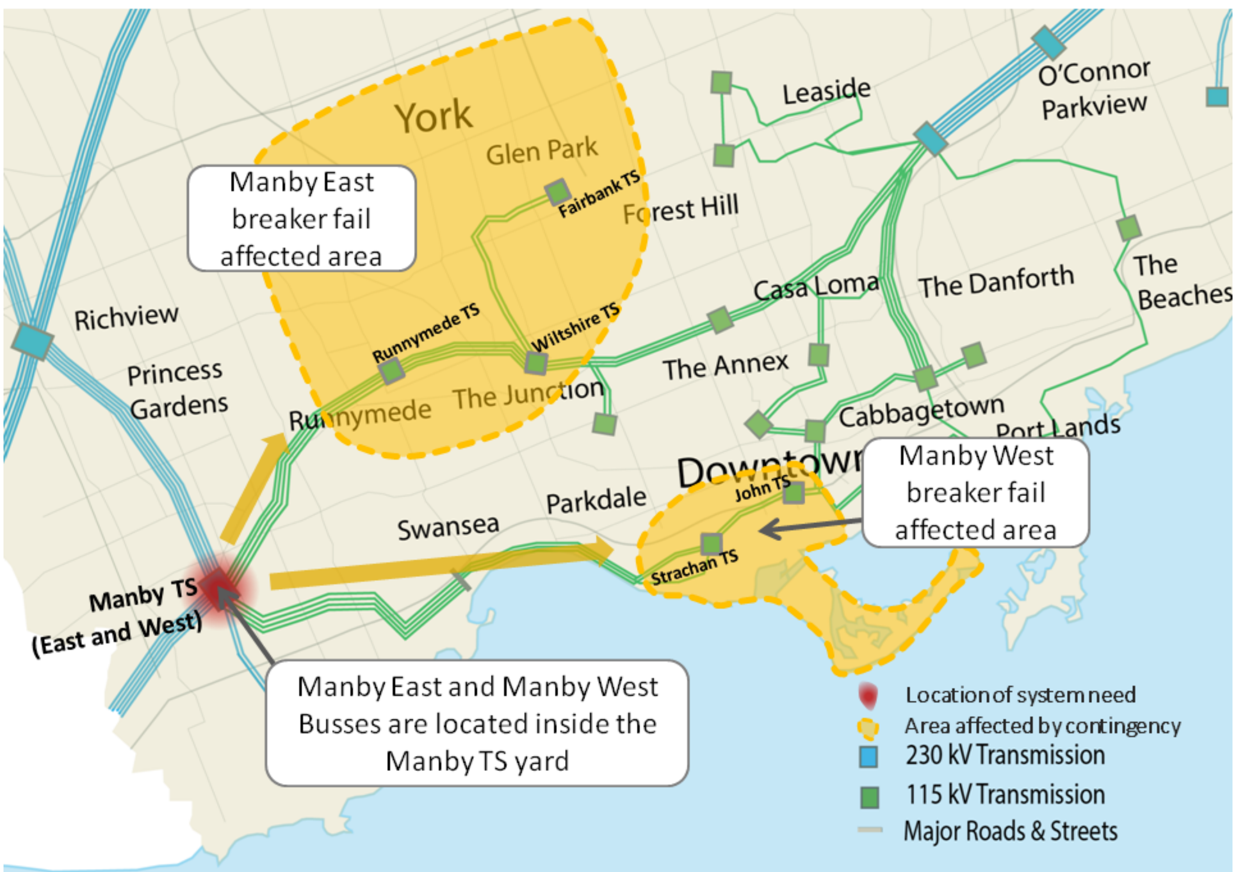
At Manby TS, this need stems from the reliability standards established for interconnected power systems in North America, as defined in the ORTAC. A breaker failure contingency at Manby TS would remove two transformers from service at the same time. The station has two independent delivery points to Central Toronto: a west bus and an east bus, each with three 230/115kV transformers to supply different parts of the Central Toronto Area, as shown in

Figure 6-2.[19] A breaker failure incident at either of these busses will result in only one of the three transformers remaining in service.

In the past, the summer peak station loads have been within the short time emergency rating of the transformer and would thereby still allow the system operator to take necessary action to reduce the transformer load in the event of the contingency. As the demand has increased in Central Toronto, there is a need to take action to ensure that the transformer loading can be reduced, and to minimize the possibility of cascading failures.

The location of the Manby TS and areas affected by the breaker failure are shown in Figure 10. Breaker failure could impact significant customer demand in the affected areas.

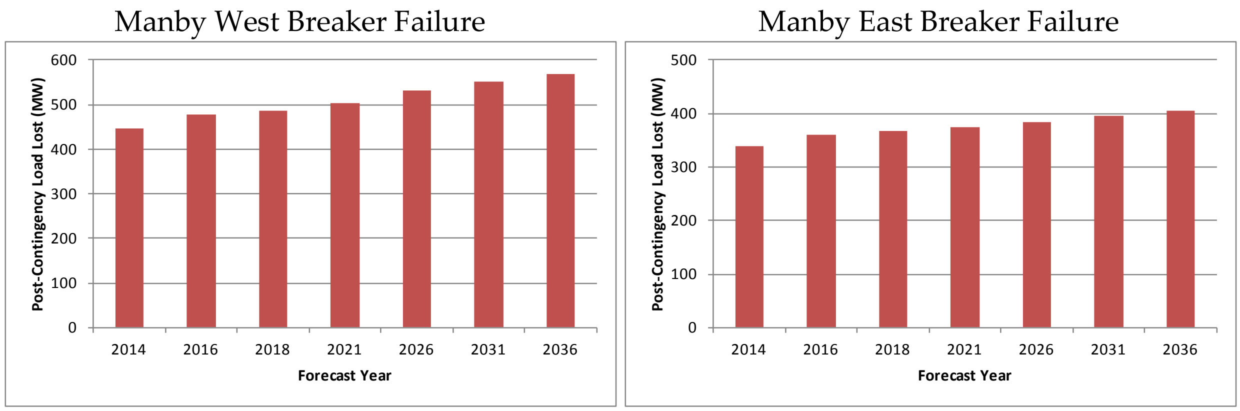
Figure 6-2: Manby TS Equipment and Affected Areas



[19] At Manby West, the failure of breaker H1H4 or A1H4 would activate breaker failure protection at the station resulting in only a single transformer to carry the full Manby West electrical demand. At Manby East, the failure of breaker H2H3 would activate breaker failure protection at the station resulting in only a single transformer to carry the full Manby East electrical demand.

As stated previously, this need occurs at each of the two independent east and west delivery points at Manby TS, affecting customers both in a large part of the downtown core and in the west Toronto area to the northwest of downtown. The severity of the need is reflected by the amount of load that would be at risk immediately following the breaker failure event. The estimated load at risk at both Manby TS busses is shown in Figure 6-3.

Figure 6-3: Forecast of Customer Load at Risk Following Manby TS Breaker Failure Events



6.2.3 Leaside TS Needs

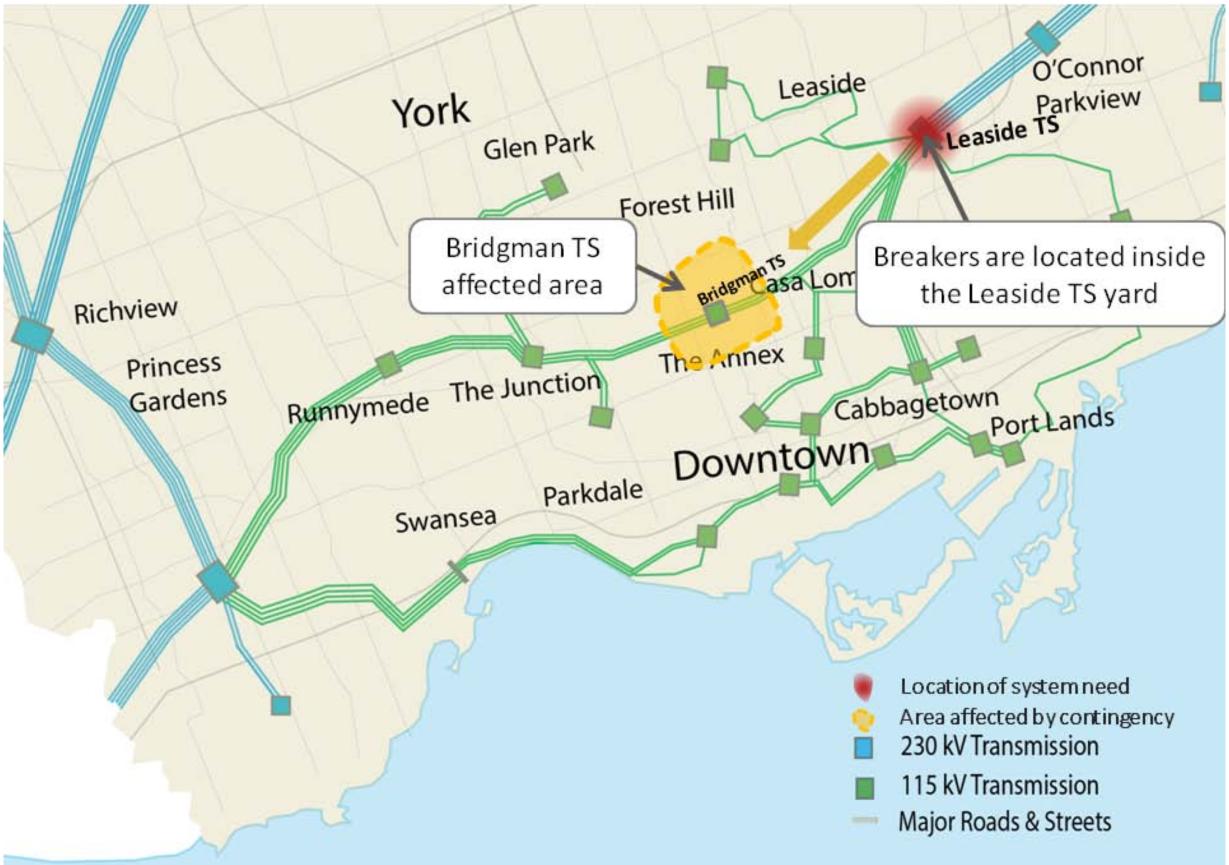
The need at Leaside TS is considered discretionary because the reliability standards (e.g., ORTAC) do not require action to be taken given system impacts and configuration, but because of the importance of security of supply in the Central Toronto Area and the important role that Leaside plays in backing up the Manby East system, the issue has been flagged in this plan.

A breaker failure contingency at Leaside TS would cause protection systems to activate and consequently remove from service two 115 kV circuits that supply the Bridgman TS to the north of downtown Toronto.[20] This would result in five of six step-down transformers at Bridgman TS being removed from service, leaving only one remaining transformer at Bridgman TS. This remaining transformer is not capable of supplying the full electrical demand of the station.

The location of the Leaside TS and the area affected by the breaker failure are shown in Figure 6-4. This breaker failure would lead to a significant outage to customers in the affected area shown.

[20] At Leaside TS, the failure of breaker L14L15, which is shared by the 115 kV circuits L14W and L15W supplying Bridgman TS, would remove both circuits from service. The cascading impact of outages at Bridgman TS would affect the supply to the area served by Bridgman TS.

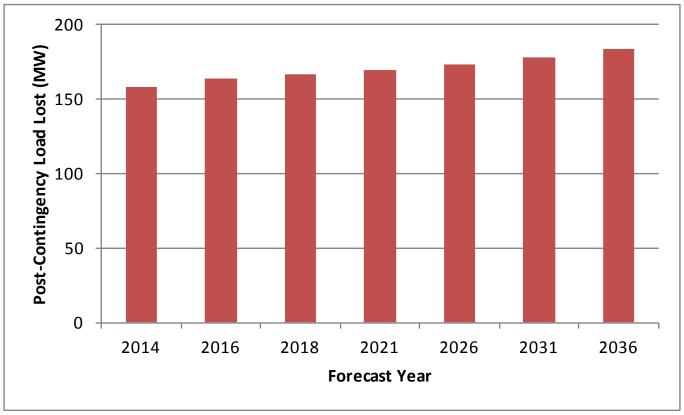
Figure 6-4: Leaside TS Equipment and Affected Areas



In contrast to the breaker events identified at Manby TS which must be addressed to satisfy the reliability standards, mitigating measures should be put in place at Leaside TS as a discretionary measure. These mitigating measures are appropriate given the number of customers potentially affected, the fact that the lines involved are also used to transfer loads from Manby during contingencies, and to improve the supply security in the area. The reliability standards require the testing of breaker failures within the Leaside TS, but since the consequence of the breaker failure do not affect the bulk electric system, the reliability standards do not require that mitigating measures be put in place.

The estimated load at risk immediately following the breaker failure event at Leaside TS is shown in Figure 6-5.

Figure 6-5: Forecast of Customer Load at Risk Following Leaside TS Breaker Failure Event



6.2.4 Capacity Relief to Supply Points in the Manby TS Sector

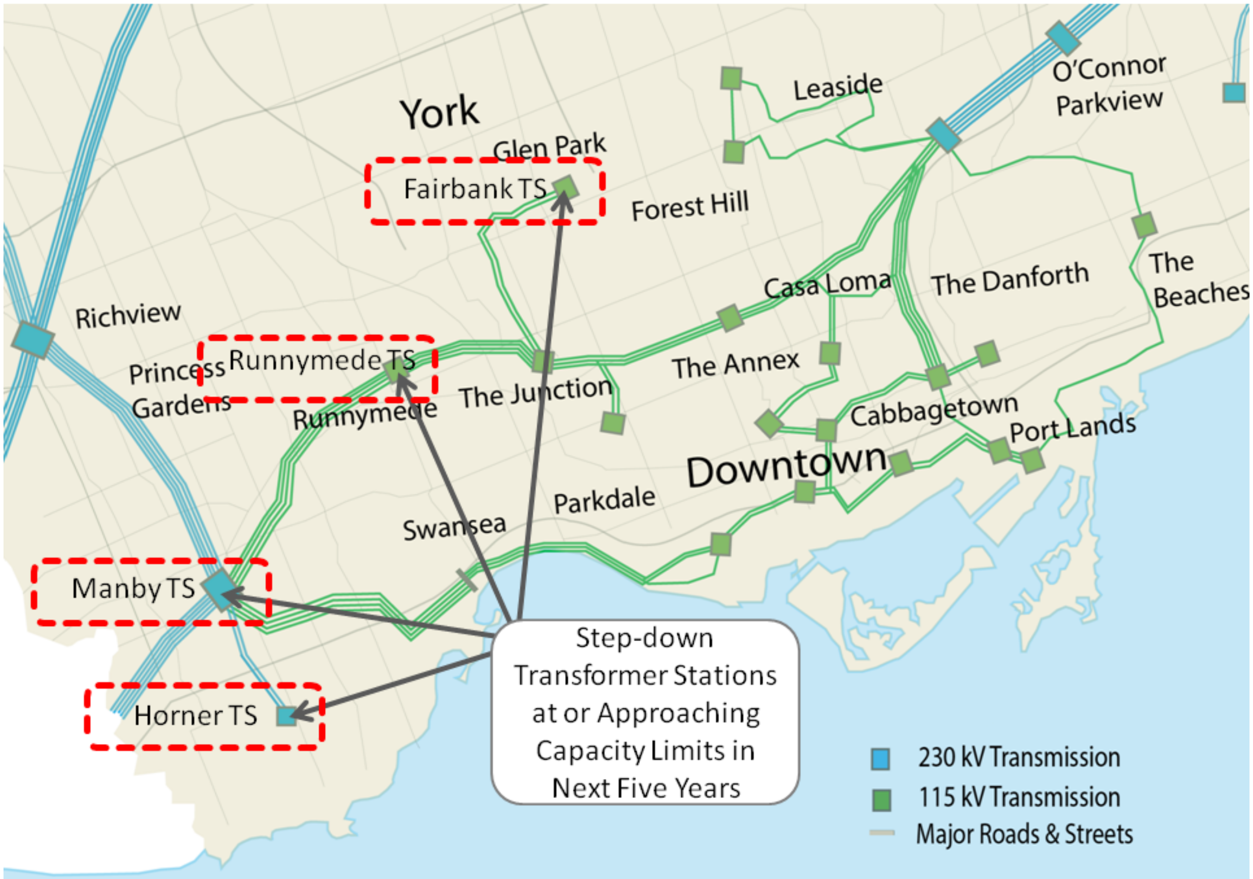
In the near term, there is a need to ensure that sufficient capacity is available to supply growing electricity demand in the west Toronto area. The capacity need occurs at the step-down transformer stations serving as electricity supply points for distribution customers in the Manby TS sector, and on the 230 kV transmission lines that supply the Manby TS from the provincial grid.

The local TS and line capacity needs are driven by continuing demand growth and by large new customer requests for connection to Toronto Hydro's distribution system. These individual TS and line needs are described separately in the following sub-sections.

6.2.5 Capacity Relief at Step-down Transformer Stations in West Toronto Area

There is a near-term need to provide capacity relief to existing step-down transformer stations serving distribution customers in the western sector. The specific distribution areas and neighbourhoods requiring the capacity relief are shown in Figure 6-6, and include the areas served by Runnymede TS, Fairbank TS, Manby TS, and Horner TS. These transformer stations provide energy transfer points between the high voltage transmission system and the distribution system, and the transmission facilities that provide supply to these stations. Runnymede TS and Fairbank TS are supplied by the 115 kV transmission system connected to the Manby East bus; and Manby TS and Horner TS are supplied by the 230 kV transmission network. The distribution voltage supplied by all four stations operates at 27.6 kV.

Figure 6-6: Station Capacity Needs in Central Toronto in the Near-Term



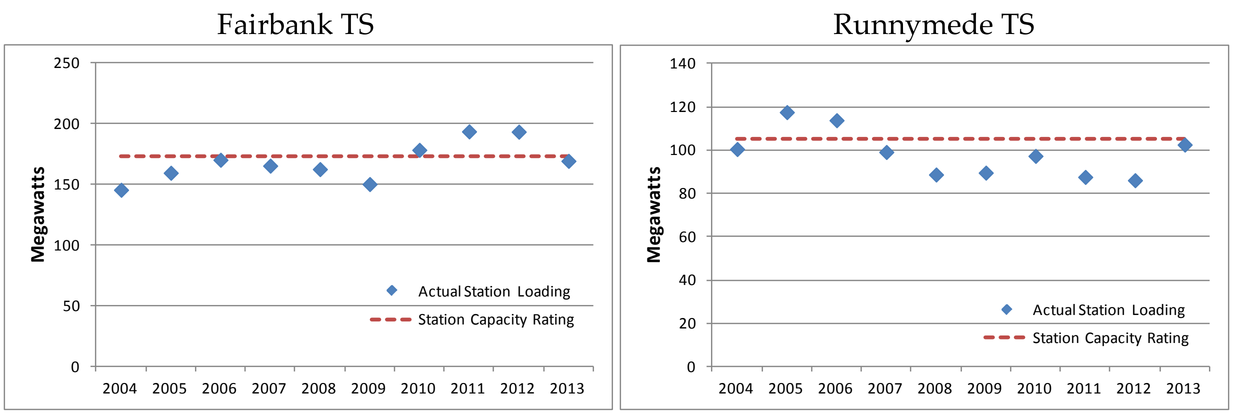
The needs in this area are being driven by the continued strong peak demand growth that has resulted in increasing new load connection request applications received by Toronto Hydro. In addition, other new large loads have signaled their intention to connect to the distribution system, such as the Eglinton Crosstown Light Rapid Transit ("LRT") ("Eglinton LRT") in the Runnymede/Fairbank area which is under construction and planned to be in service by 2019. Based on the geographic separation of the station areas, and the different growth drivers, the need for capacity relief in this area has been separated into two sub-areas: (1) Runnymede TS and Fairbank TS, and (2) Manby TS and Horner TS.

Runnymede TS and Fairbank TS

Both Runnymede TS and Fairbank TS are operating close to the station capacity during the peak demand period. A review of historical loadings at these stations shows that both Runnymede

TS and Fairbank TS have exceeded their 10-day limited time ratings (LTR) in the last 10 years, as shown in Figure 6-7.[21]

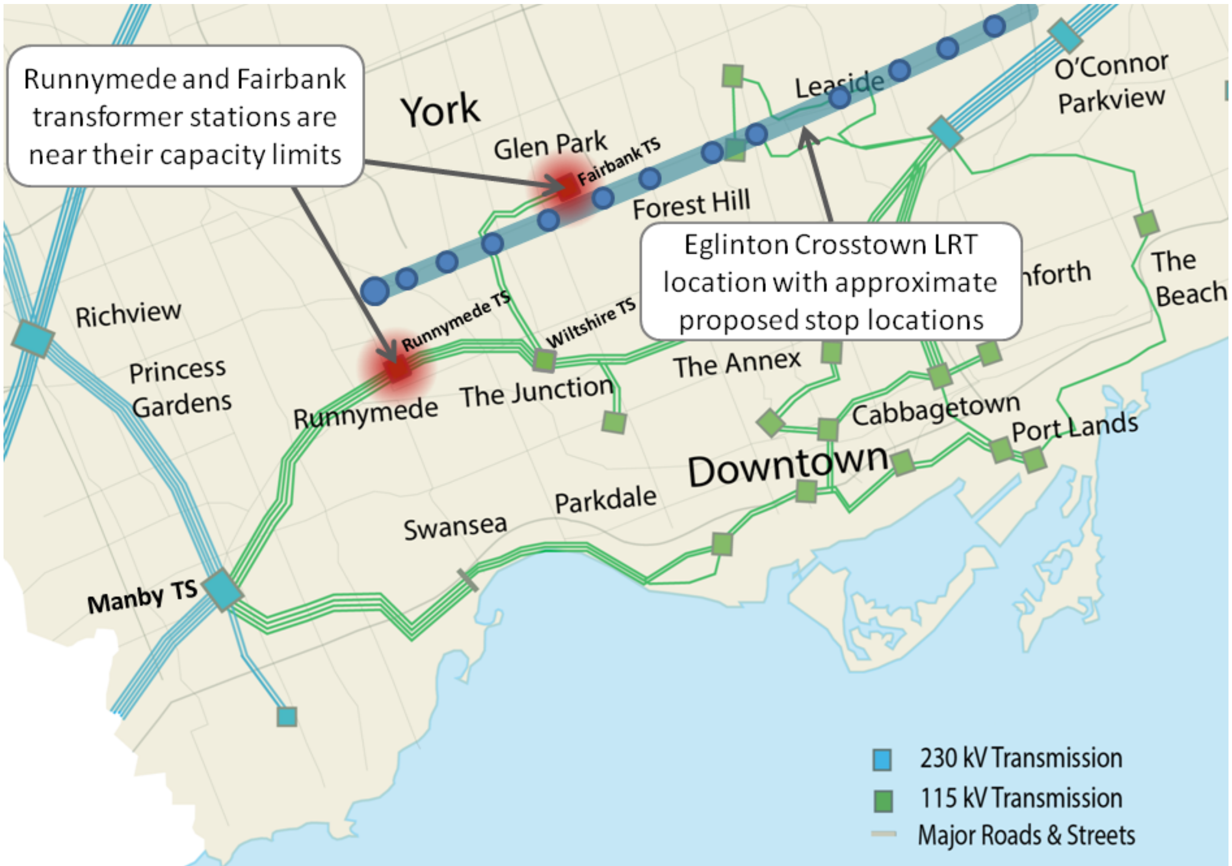
Figure 6-7: Runnymede TS and Fairbank TS Historical Peak Station Loadings



The service area of Runnymede TS and Fairbank TS is experiencing re-development, as well as being host to a portion of the Eglinton LRT project by MetroLinx. The Eglinton LRT project will add approximately 80 MVA (72 MW) of new load within Toronto, with over 20 MVA (18 MW) to be supplied from the west terminus of the line, near Runnymede TS. The location of the Eglinton LRT in relation to Runnymede TS and Fairbank TS is shown in Figure 6-8. As with other areas served by public transit facilities in Toronto, further land development and intensification due to the presence of new mass transit is expected to occur in the future.

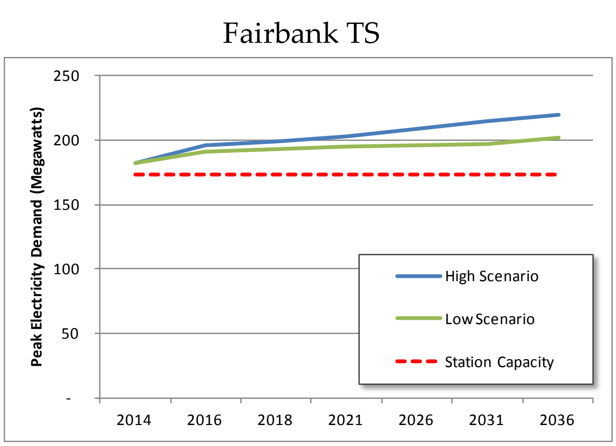
[21] The station capacity ratings were provided to the Working Group by Toronto Hydro and Hydro One.

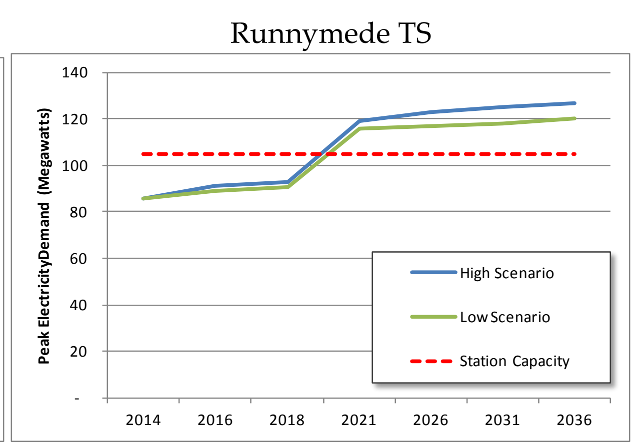
Figure 6-8: Eglinton LRT Project Location in Relation to Supply Points in West Toronto



The demand forecast for Fairbank TS and Runnymede TS is shown in Figure 6-9. Both stations are forecast to require relief. The impact of the Eglinton LRT at the Runnymede TS will exceed the station's capacity to supply the load.

Figure 6-9: Runnymede TS and Fairbank TS Peak Demand Forecast

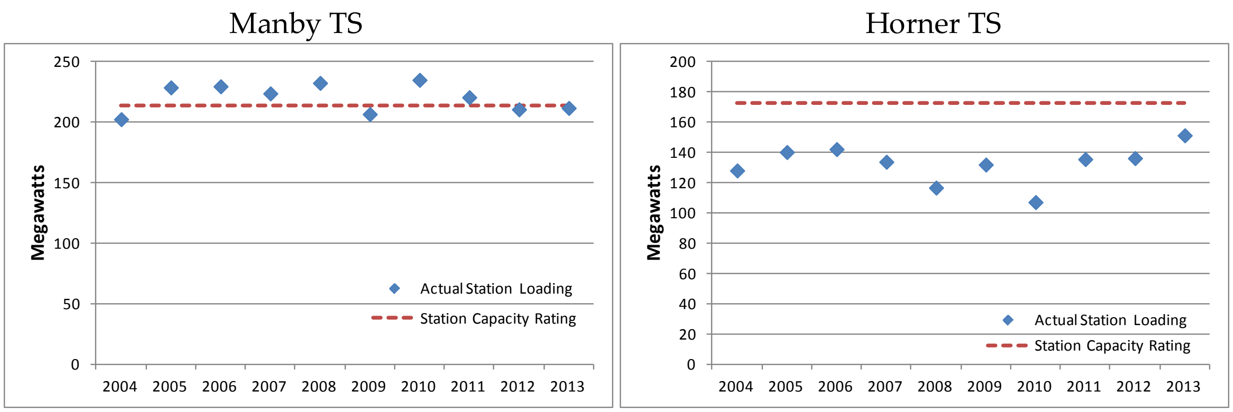




Manby TS and Horner TS

Both Manby TS[22] and Horner TS are operating close to the station capacity during the peak demand period. Manby TS is operating at its LTR and Horner TS was at 88% of its LTR in 2013, as shown in Figure 6-10. Manby TS has exceeded its capacity rating in past few years. Toronto Hydro has implemented several projects to relieve Manby TS in recent years through transfers to Horner TS, exhausting most, if not all, of the economic load transfer ability to Horner TS.

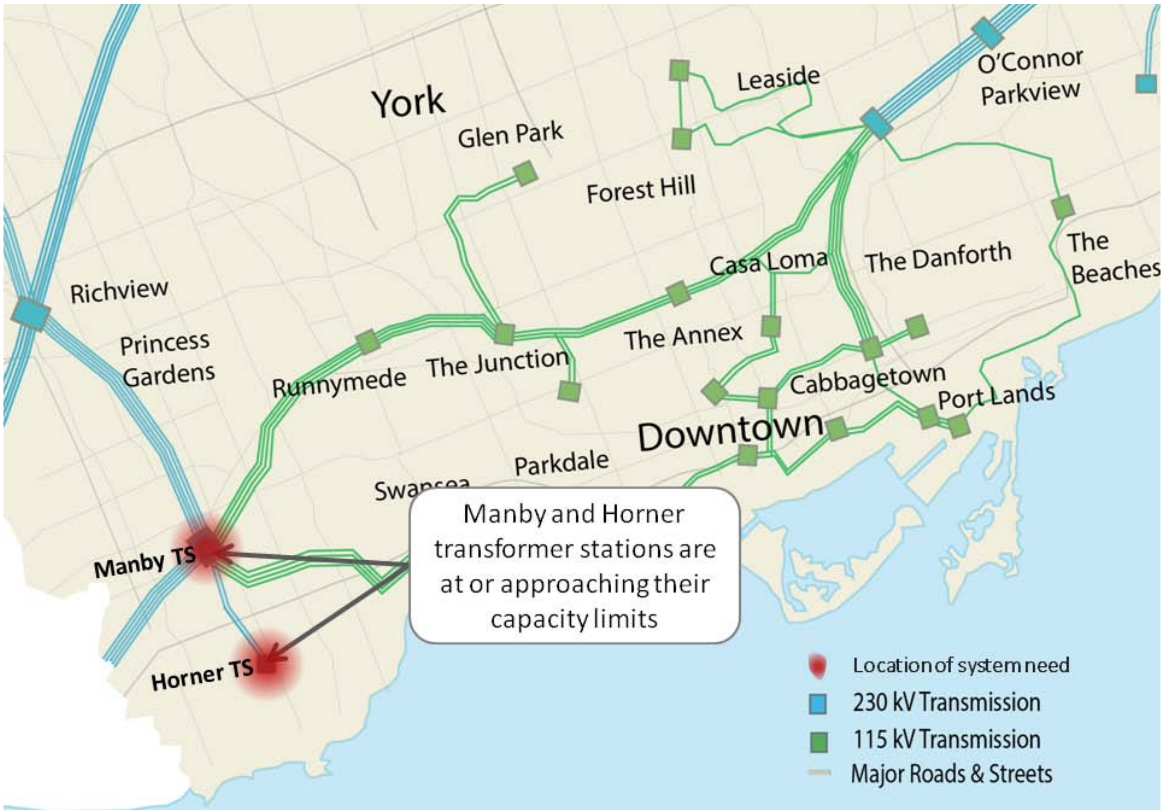
Figure 6-10: Manby TS and Horner TS Historical Peak Station Loadings



A consideration for Manby TS and Horner TS is continuing customer interest in connecting to the stations in this area. The location of Manby TS and Horner TS is shown in Figure 6-11.

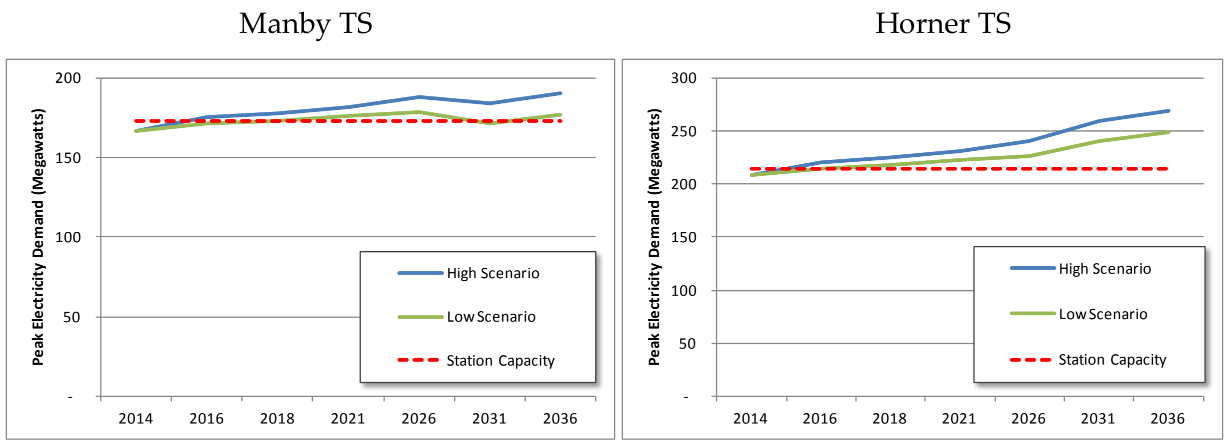
[22] This need refers to the capacity of the Manby TS step-down transformers that supply the local distribution network in the Islington City Centre area (230/27.6 kV), different from the 230/115 kV transformers that supply other parts of the Central Toronto Area via the 115 kV transmission system.

Figure 6-11: Manby TS and Horner TS Supply Points in West Toronto



The demand forecast for Manby TS and Horner TS is shown in Figure 6-12. Capacity relief at both stations is needed in the near-term period.

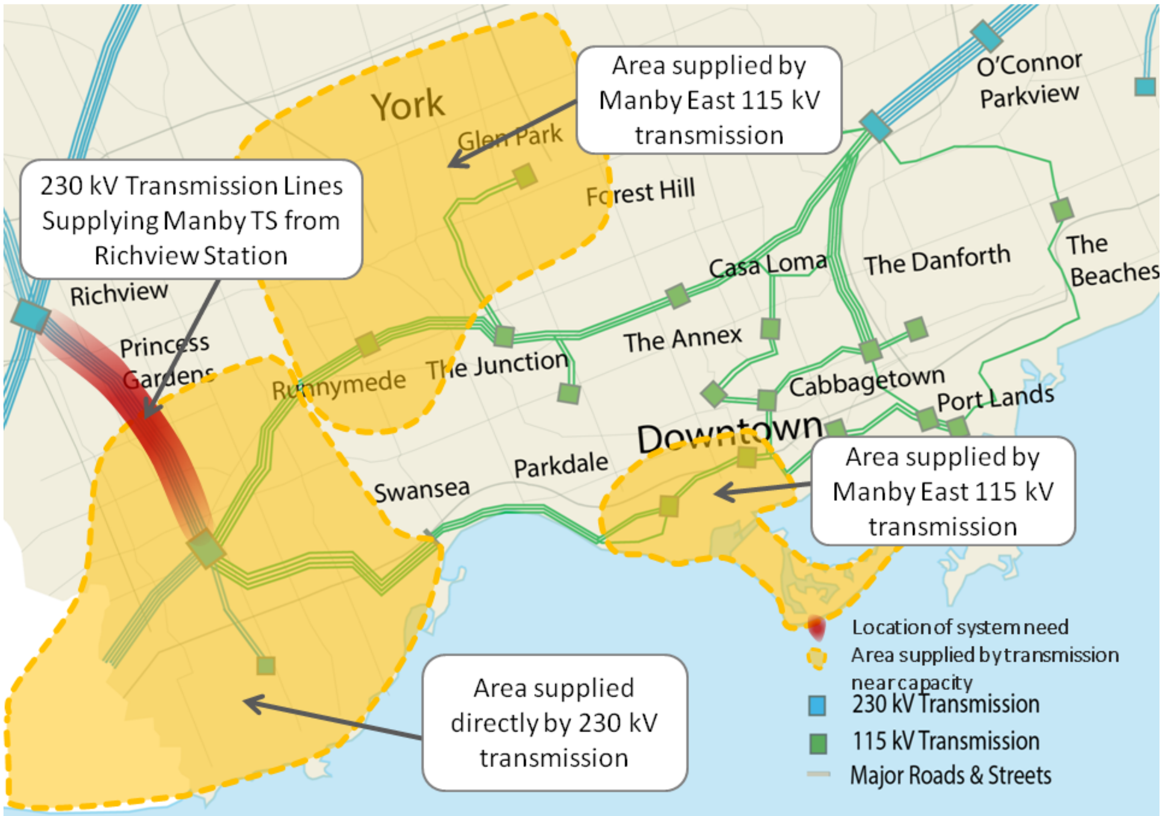
Figure 6-12: Manby TS and Horner TS Peak Demand Forecast



6.2.6 Capacity Relief for Richview x Manby 230 kV Transmission Corridor

At the end of the near-term period, there is a need for additional capacity on the 230 kV transmission lines that supply Manby TS from Richview TS. Richview TS is a major switching station and a main hub of supply from the provincial grid to customers in the western and northwest Greater Toronto Area. The Richview to Manby transmission corridor is the main supply path for a large part of the Central Toronto Area, including downtown Toronto, as well as southern Mississauga and Oakville. Manby TS is supplied by four 230 kV circuits from Richview TS along the corridor shown in red in Figure 6-13. The areas supplied by these transmission facilities are also shown in Figure 6-13 as orange shaded areas.

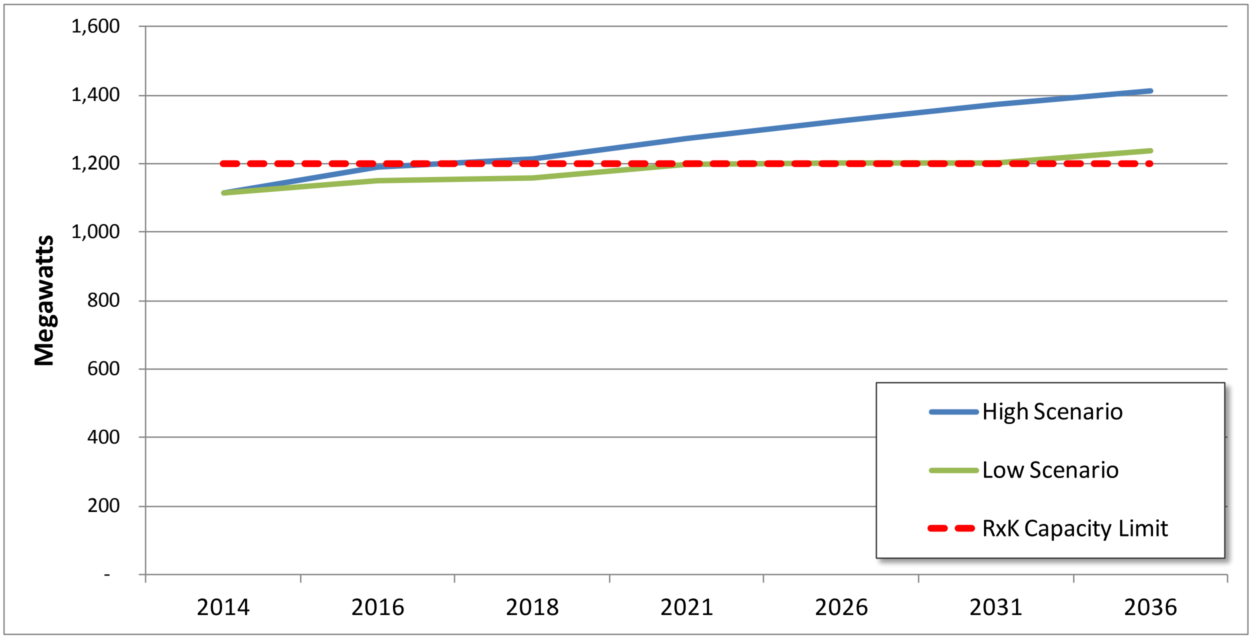
Figure 6-13: Richview – Manby 230 kV Transmission Capacity Needs



Note: The area supplied by Richview – Manby 230 kV transmission includes the Western Sector of the study area and the southern portion of Enersource and Oakville Hydro LDC franchise territory.

In 2014, Hydro One completed work to re-position the 230 kV tap points that supply Horner TS from the Richview – Manby transmission circuits. This project improves the load balancing of Horner TS supply across the Richview – Manby circuits, resulting in better utilization of existing facilities and providing some near-term capacity relief on the Richview – Manby corridor. Other new customers seeking connection to the power system in the Manby TS service area, such as the Eglinton LRT discussed in the previous section, will however add to the need for capacity relief by the end of this decade. The demand forecast for the Richview – Manby transmission corridor is shown in Figure 6-14. The forecast indicates that the capacity of this transmission corridor will be reached between 2018 and 2021, depending on the forecast scenario. Given the lead time for transmission, conservation and DG options, this need is considered urgent.

Figure 6-14: Forecast for Richview – Manby 230 kV Transmission Corridor



The electrical demand for transmission facilities in southern Mississauga and Oakville are excluded from the Richview – Manby ("RxK") corridor forecast and subtracted from the capacity limit shown above. The peak demand in these areas, also supplied via the Richview – Manby corridor is approximately 370 MW.

6.3 Medium-Term Needs

6.3.1 Capacity Relief to Supply Points Serving the Eastern (Leaside TS) Sector

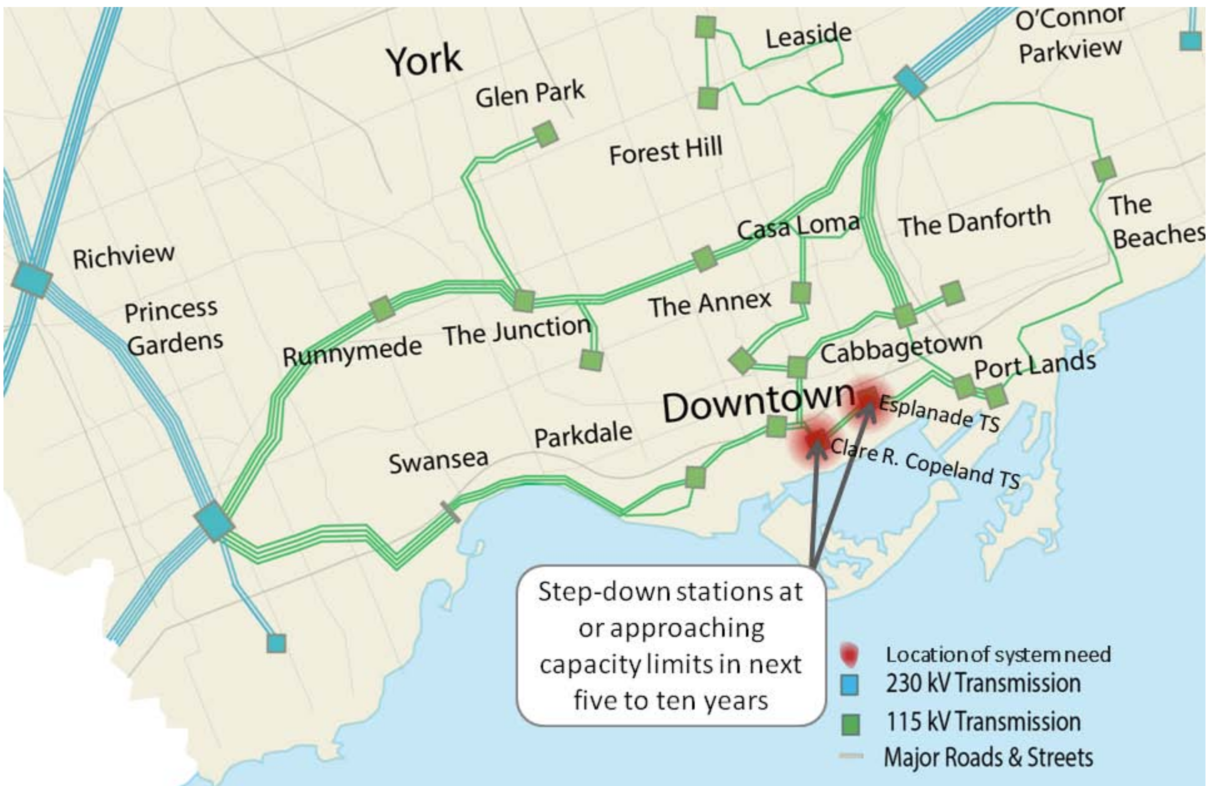
In the medium-term, there is a need to ensure that sufficient capacity is available to supply growing electricity demand in the downtown Toronto area, at the electricity supply points serving distribution customers in the downtown business district. This need is driven by continuing demand growth and by new customer connection requests.

6.3.2 Capacity Relief at Step-down Transformer Stations in the Downtown Area

There is a medium-term need (as early as 2021) to provide capacity relief to the Esplanade TS and Clare R. Copeland TS ("Copeland TS," phase one of which is currently under construction), which serve customers and supply growth in the downtown core. The stations requiring relief are shown in Figure 6-15.

Copeland TS will be used by Toronto Hydro to enable new customer connections, enable equipment renewal to address end-of-life issues at other downtown stations, and provide capacity relief. Once the first phase of Copeland TS is brought into service in 2016, Toronto Hydro expects that a combination of growth within the area and reconfiguration of adjacent station service areas will fully utilize the capacity by 2021, primarily because the station will pick up the growth from other adjacent, fully utilized downtown transformer stations, and connect new customers in the area.

Figure 6-15: Station Capacity Needs in Downtown Toronto in the Medium-Term



According to the load forecast, approximately 10 MW of relief will be required at Esplanade TS as early as 2016, with the amount of relief increasing to 30 MW by 2026. It is estimated that up to approximately 90 MW of additional customer load will be seeking connection in this area in the next five years. This estimate is based on recent information and is incremental to the load forecast provided for the IRRP. In addition, when Copeland TS is brought into service, the station will accept load from the nearby John TS and other transformer stations in the area, to free capacity to perform refurbishment work at John TS, as well as to provide relief to other downtown stations. Copeland TS is therefore expected to be at capacity very soon after commissioning, and following the reconfiguration of existing station service areas. The need at Esplanade TS indicated in the load forecast will be deferred further into the future.

6.4 Other Observations for Addressing the Quality of Electricity Service

6.4.1 Probabilistic Reliability Assessment of Performance in Central Toronto

Electricity service reliability performance in the Central Toronto study area has typically exceeded reliability standards levels. The IRRP considered options for maintaining these high levels of service in the context of developing the plan. This approach was supported by stakeholder engagement feedback, which indicated that customers in the area expect very high electricity service reliability, including few interruptions and quick restoration of service when interruptions do occur.

To determine whether customers in Toronto should be provided with a higher level of electricity service, a review of utility practice in other jurisdictions containing major metropolitan areas was carried out. The review indicated that many utilities plan to meet higher levels of service reliability in central business areas as compared to outlying areas. About half of the utilities planned to achieve better reliability in central business areas or, in some cases, the capital region of their territory. Not all utilities planned or achieved higher reliability levels in the same manner. For example, some jurisdictions plan redundant transmission infrastructure, some have policies to ensure that greater amounts of generation are located within the load centre, some coordinate transmission and distribution planning more closely to enable one system to better back up the other, and several rely more heavily on special protection systems or operational schemes to provide higher levels of reliability in urban areas, rather than relying on more expensive infrastructure solutions. A summary of the review of planning standards in major metropolitan areas is provided as Appendix F.

A common practice in several jurisdictions is to employ probabilistic assessment tools to assess the reliability risk to customers, and to find solutions – the cost of which may correspond to the potential economic impact of the risk. For the Central Toronto IRRP, a probabilistic reliability assessment was conducted as a means of estimating the risk to customers inherent in the electricity system supplying the area, and to test the resiliency of the electricity system under outage contingency scenarios that are beyond the levels required by the reliability standards (e.g., ORTAC). The PRA took into account the probability of the outages, relying on historical outage statistics of the various classes of equipment, including the frequency and the duration of historical outages.

The PRA results, provided in Appendix E, indicate that the transmission system serving the central part of the city has an inherent design that provides good flexibility for containing the impact of, and recovering from, such events. The design features of the local power system, coupled with the available operator control actions, result in the ability to restore service within a relatively short period of time, considering the magnitude of the types of outages assessed.

Actual experiences from recent major events confirm these findings. Root-cause analyses conducted subsequent to these major events have also incorporated system improvements that further mitigate the risk in the future. Given the low likelihood of occurrence associated with such incidents and the improvements which have been put in place to mitigate the known risks, the Working Group's view is that the cost of added transmission reinforcements to mitigate the residual risk is not justified. This was the case even when the economic impacts of customer outages were taken into account.

The annual monetized risk[23] of outages on the system is in the order of $6 million per year, reflecting the very low probability of multiple coincident transmission element failures. In addition, the risk of customer impact from outages is generally evenly distributed across the 115 kV system, with no one station or transmission service area being disproportionately vulnerable to outages as compared to any other. This finding indicates that there is no single transmission system fix that will substantially enhance supply security for the 115 kV transmission system area.

This PRA found that the greatest risk inherent within the 115 kV transmission system in Central Toronto is related to double transmission element contingencies at the individual step-down transformer station level. The coincident failure of two transformers or their transmission supply lines, on average, result in an annual monetized risk of just under $1 million per year. This indicates that the cost of mitigating solutions should be consistent with this benefit. Higher-order contingencies such as three elements failing at once (e.g., N-3) represent a very low risk to customers due to their very low probability of occurrence.

[23] Using assumptions for the value of customer reliability, the amount of expected unserved energy can be expressed as a monetary value. These assumptions are found in Appendix E.

6.4.2 Assessment of Impact of Extreme Contingencies (Low Probability – High Impact Events)

A number of specific "extreme contingencies" were assessed as part of the needs assessment, such as the loss of key transformer stations supplying the downtown Toronto 115 kV system and the loss of one or more multiple circuit structures (i.e., transmission towers). The contingencies assessed were selected by the Working Group based on a number of known possible scenarios that are beyond the scope of the normal planning criteria and more extreme than would be considered in the PRA discussed in the previous section, but for which an assessment was warranted due to the magnitude of the possible impact on customers.

The reliability standards[24] recognize the loss of a substation, transmission corridor and/or a major load centre as "extreme contingencies." While such extreme contingencies have a very low probability of occurring, the consequences can be high as the resulting interruptions can be widespread and/or take a long time to restore. While the design of the power system is not required to withstand such events without interruption of service, planning authorities assess extreme events for the potential impact and review if measures to mitigate the risk can be justified. Mitigation may include attempting to reduce the likelihood of load being interrupted, or more commonly reducing the extent and/or duration of unsupplied load following an extreme contingency. The ORTAC does not prescribe the degree of mitigation required and it is left to individual jurisdictions to assess the risk of extreme events and to determine if mitigation measures can be justified and incorporated in long-term plans.

The technical summary of the impact of extreme contingencies is not included with this IRRP due to security concerns.

6.4.3 Consideration of Plans for Transmission Infrastructure Renewal

Given the age of many of the transmission facilities in the area, the IRRP study assessed the potential impact on supply reliability of major facilities reaching end of life within the study period. Some facilities in the Central Toronto 115kV system are expected to require replacement or refurbishment over the next several years. The Hydro One report, "Summary of Asset Condition and Sustainment Plans for the Leaside and Manby 115kV System," included as Appendix G, identifies aging facilities in all major asset classes: overhead lines, underground cables, transformers, breakers and other switchgear equipment.

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[24] Northeast Power Coordinating Council ("NPCC") criteria, as referenced in the ORTAC.

The refurbishment plans included in Hydro One's report were assessed using the demand forecast for the specific years representing the time periods:

- 1-5 years: 2016 forecast demand was assessed;
- 6-10 years: 2021 forecast demand was assessed; and
- 11-15 years: 2026 forecast demand was assessed.

The high demand forecast scenario was used for this assessment because this scenario represents the worst case loadings on the equipment supplying the area. The robustness of the transmission system, considering the planned outages that outlined in Hydro One's report, was tested by considering a contingency event in addition to the planned outage.

The assessment concluded that, given the process in Ontario for approving and taking equipment outages, it is expected that the local power system will have sufficient flexibility to accommodate the outages required to perform the planned refurbishment work.

The staging of certain refurbishment work, or strategies to keep existing facilities in service while replacement infrastructure is being built, and transferring customer supply to alternate sources, will help to mitigate risk of service interruptions during refurbishment periods.

7. Near-Term and Medium-Term Needs and Alternatives

The core elements of the near-term plan must include measures to enhance supply security and ensure that reliability standards continue to be met, and to ensure that sufficient infrastructure capacity is available to supply near-term growth. It is recommended that this be done by continuing with local conservation planning and implementation efforts, and proceeding with certain near-term infrastructure reinforcements to ensure that new customer demand can continue to be connected to the system. Finding opportunities for further DG resource development in the near and medium term is also recommended for improving the supply diversity and supporting system resilience.

This section describes the alternatives considered in developing the near and medium-term plan for Central Toronto and provides details of and rationale to support the recommended plan.

7.1 Alternatives Considered for Meeting Near- and Medium-Term Needs

In developing the near and medium-term plans, the Working Group considered a range of integrated alternatives. These alternatives balanced maximizing the use of the existing infrastructure with costs, and the need for enhancing the capacity, security and reliability of electricity service. A key objective in developing the plan was to ensure that longer-term infrastructure options are kept available and that the plan can adapt to a future in which the demand, resources and technology development are uncertain.

The following sections detail the alternatives that were considered, and comments on their performance in the context of the criteria described above.

7.2 Near-Term Alternatives

7.2.1 Addressing Supply Security Risk at Manby TS and Leaside TS

The supply security risks stemming from the possible breaker failure events at the Manby and Leaside transformer stations are generally recognized as having a low probability of occurring. However, should these events occur there would be significant electricity service interruptions to customers supplied downstream from these facilities. Given the high potential consequence of these events, the number of technically feasible, cost-effective alternatives available for mitigating these risks is limited.

The alternatives that were considered for addressing these needs are discussed below.

Operational Measures (e.g., a Special Protection System, or "SPS")

A SPS can be designed to maintain the electrical demand within the capability of the transmission and distribution equipment that is remaining in service following a critical breaker failure event. These are operational measures that are automated, and do not typically involve major infrastructure upgrades.

The SPS is estimated to require one to two years for design and implementation, with a total cost in the order of $1 million to $3 million.

The use of an SPS is an acceptable solution for satisfying the ORTAC. SPSs are commonly used by utilities worldwide to enhance electricity service security for low probability, high consequence events. The SPS can be implemented quickly and more cost-effectively than other infrastructure based alternatives.

These types of automatic schemes are generally only triggered under very rare circumstances (although they may be "armed" and ready more often). When triggered, customer demand can be reduced in a strategic manner in order to maintain the equipment remaining in service below its emergency ratings and to prevent cascading failures and a wider customer impact. This also enables service to be restored more quickly. Specific customers that are interrupted can be selected based on criticality.

Another benefit of an SPS is that is can be designed and scoped to mitigate the impact of other rare equipment outage events, such as a partial or complete loss of Manby TS or Leaside TS or the loss of two circuits on a multi-circuit tower structure. These additional contingencies were assessed as per the analysis described in Section 6.4.2 and discussed with the Working Group in the context of the SPS alternative.

It is acknowledged that a SPS can introduce operational elements with associated risks that may need to be assessed and managed, such as the risk of failure on activation, inadvertent operation, as well as maintenance and coordination requirements between the transmitter, system operator, and the LDC.

Conservation and Distributed Generation

Conservation and DG are not technically feasible options for addressing these specific needs because there is not enough conservation achievable potential within the affected areas to address the risk within the timeframe required. A summary of each of the needs identified by the assessment, and the amount of conservation achievable potential within the affected areas is provided in Appendix H.

Furthermore, conservation is typically not used to address these types of security risks. However, conservation and DG resources that can be called upon to reduce the demand when needed can help to reduce overall equipment loadings, and thereby reduce the number of hours that a SPS needs to be armed, or to help manage equipment loadings while restoration of service is taking place following the contingency.

Reconfiguration of Station Facilities

An alternative option to address these security risks involves reconfiguring the bus work at the transformer station so that the breaker failure does not automatically remove multiple transmission system elements from service.

The reconfiguration requires significant capital work inside of a major transformer station that would take at least 2 to 3 years to design and implement, and with a cost that is several times more than a SPS.

This option is not precluded by the SPS alternative. It could be implemented coincident with other station refurbishment work as an incremental improvement at a later date, subject to a cost-benefit analysis at the time.

Status Quo

Doing nothing is not an option at Manby TS as this would not satisfy the applicable reliability standards. Doing nothing at Leaside TS would not contravene reliability standards; however, ORTAC Section 7.4 provides guidance for justifying this work based on the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost.

Summary

Given the rare nature of the events discussed in Section 6.2.1, operational measures, such as an SPS, is the only alternative that is technically feasible to implement in the time required, and at a cost that is commensurate with the rarity that it is expected to be needed. The cost of implementing the SPS is estimated to be in the range of $1 million to $3 million, and could be implemented within one or two years.

The use of SPSs to limit the impact of failures of this nature is a common practice of utilities worldwide. These systems can minimize cascading equipment outages that result in the propagation of service interruptions to customers. By way of strategically maintaining electrical demand within equipment ratings, a SPS can reduce the extent of further equipment outages and the amount of customer load impacted. A SPS is especially useful to reduce the risk of rare equipment failures such as a breaker failure. Compared to additional redundant infrastructure, station or line work, a SPS can be implemented more quickly and at a lower cost.

A summary of the attributes of the alternatives considered is shown in Table 7-1.

Table 7-1: Summary of Alternatives for Improving Supply Security Risks

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Operational measures (e.g., SPS)	YES	YES	1-2	1-3	Preferred approach based on least cost and time to implement for improving system resilience for breaker failures
Conservation / DG	NO	N/A	N/A	N/A	Insufficient potential within the area to mitigate the risk for a these low probability events
Reconfiguration of station facilities	YES	YES	2-3	10-30	Costs several times more than a SPS, but a potential medium to longer-term option if done in conjunction with other station refurbishment work
Status quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.2.2 Addressing Capacity Relief at Runnymede TS and Fairbank TS

A number of alternatives for providing the capacity relief required to supply growing demand in the area were considered. Given that the transformer stations in the area are already near or at capacity, and the new Eglinton LRT load will be connecting to the distribution system in the near-term period, there are limited alternatives available that are able to meet the need within the time required. The need for capacity relief in the Runnymede TS and Fairbank TS area is urgent. Only Runnymede TS has the space needed to accommodate new transformation facilities.

The alternatives that were considered for capacity relief in the Runnymede TS and Fairbank TS area are discussed below.

Distribution Feeder Ties to Transfer the Load to Other Load Stations and Deferred New Transformation Capacity

This alternative involves building additional distribution feeder capacity by way of 27.6 kV interties between the overloaded stations and adjacent stations to enable permanent load transfers.

This allows for electrical demand to be transferred from Runnymede TS and Fairbank TS to adjacent stations with spare capacity (e.g., Richview TS and Bathurst TS), and to supply the Eglinton LRT using existing feeder positions from the existing stations. Achieving these transfers involves constructing several new 27.6 kV distribution voltage feeders between Runnymede TS and Richview TS, and Fairbank TS and Bathurst TS. The feeder tie routes are expected to be technically challenging due to the distances involved and the number of physical barriers in the area (e.g., highways, bridges, waterways, etc.). The distance from Runnymede TS to Richview TS is approximately 7.5 km, and from Fairbank TS to Bathurst TS is 7 km. These long feeders may have reliability performance and/or voltage quality issues due to their lengths.

The estimated cost of the distribution feeder ties is estimated to be $70 million to transfer loads and to supply the new growth. This alternative is subject to significant cost uncertainty due to the physical barriers in the area and the potential power quality challenges. Within about

10 years, transformation capacity will still be required at an additional cost of about $34 million.[25] Therefore, the total cost of this alternative is approximately $104 million.

Expanding the Existing Runnymede TS to Provide Relief to Fairbank TS and Supply New Customer Demand

This alternative involves installing an additional bus and transformation capacity at Runnymede TS, and upgrading the 115 kV lines between Manby East and Wiltshire TS, as well as building distribution feeder ties between Fairbank TS and Bathurst TS to transfer loads.

There is available space for the expansion at Runnymede TS and therefore, this alternative would not require additional property acquisition.

Increasing the load serving capability of Runnymede TS requires that other system impacts be considered. Runnymede TS is supplied from the 115 kV lines originating at Manby TS (circuits K11W and K12W that run from Manby TS to Wiltshire TS). Installation of new capacity at Runnymede TS would increase the power flow requirements on these 115 kV lines and therefore will require upgrades to the 115 kV lines between Manby TS and Wiltshire TS.

The estimated cost of this alternative is $90 million, which includes $34 million for Runnymede TS expansion, $16 million for upgrades to the 115 kV network, and $40 million for distribution feeders/service for supplying new growth.

Conservation

Conservation is not a technically feasible alternative for providing the capacity relief because there is not sufficient conservation achievable potential within the affected areas to address the capacity relief that is needed and to supply the new customers seeking to connect in the area by 2019.

The assessment of the amount of conservation achievable potential within the affected area is provided in Appendix H.

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[25] This cost is the present value of the cost of expanding the Runnymede TS with additional transformation and bus capacity, and upgrading the 115 kV transmission lines between Manby TS and Wiltshire TS to enable the increased power flow requirements ($50 Million future cost expressed in present day dollars by applying a 4% discount rate).

Distributed Generation

The implementation of DG is not a technically feasible alternative to address this need because it would require strategically locating a sufficient amount of DG resources to relieve the specific TSs and feeders. Through recent procurement efforts and community outreach, the IESO is not aware of any such DG opportunities in the area that would defer or avoid this need.

Status Quo

Doing nothing is not a feasible alternative as it will not permit the connection of the new customer demand or provide relief to the stations already near or at capacity.

Summary

Based on the overall comparison of the costs, benefits and feasibility of the various alternatives, the expansion of the existing Runnymede TS is recommended as the preferred solution to address the need for capacity relief at the existing stations in the area and to supply new growth in the area, including the Eglinton LRT project.

Building distribution feeder ties defers the need date for incremental transformation capacity but carries significant cost due to the complexity of constructing new distribution feeders to transfer the electrical demand over long distances across a number of physical obstacles including major highways and waterways), and power quality concerns. This alternative requires an increase in transformation capacity in the area in about ten years to supply continued growth.

The upgrading of the 115 kV transmission service from Manby TS to Wiltshire TS associated with the Runnymede TS alternative will preserve the flexibility to transfer demand between Leaside TS and Manby TS in the event of system emergencies, and provides long-term capacity to supply demand growth and further expansion in the area.

A summary of the attributes of the alternatives considered is shown in Table 7-2.

Table 7-2: Summary of Alternatives for Providing Capacity Relief at Runnymede and Fairbank TS

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Distribution load transfers and deferred new transformation	YES	YES	2-3	104	Technical feasibility uncertain due to distance and physical barriers; subject to high degree of cost uncertainty, and will still require additional transformation capacity and transmission upgrades in ten years' time
Expand existing Runnymede TS	YES	YES	2-3	90	Provides service for Metrolinx, relief for existing stations and capacity for future growth; no new sites required
Conservation	NO	N/A	N/A	N/A	Insufficient potential to provide relief for existing stations and permit connection of new customers
DG	NO	N/A	N/A	N/A	Insufficient potential to provide relief for existing stations and permit connection of new customers
Status quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.2.3 Addressing Capacity Relief at Manby TS and Horner TS

A number of alternatives for providing the capacity relief required to supply growing demand in the area were considered. Given that the transformer stations in the area are already near or at capacity, there are limited options available that are able to meet the need within the time required. Capacity relief is required at both Manby TS and Horner TS in the near term. There is no available space at Manby TS to accommodate new transformation capacity or high-voltage facilities. Horner TS has space available to accommodate the installation of a new bus and transformation capacity.

The alternatives that were considered for capacity relief at Manby are discussed below.

Distribution Feeder Ties to Transfer the Load to Other Load Stations

The distribution alternative involves building additional distribution feeder capacity between Manby TS and Richview TS to permanently transfer loads from Manby TS to Richview TS for relieving Manby TS. This includes constructing several new 27.6 kV feeders that tie existing feeders from the service area of Manby TS to Richview TS.

The estimated cost of this alternative is $77 million. This alternative carries a high level of cost uncertainty due to the distance and number of physical obstacles that require crossing, such as railway corridors, as these types of physical obstacles and barriers can substantially impact the project cost. Furthermore, distribution transfers can result in the demand being supplied by long distribution feeders which may have a reliability impact.

Although this alternative allows for spare capacity at Richview TS to be utilized, it does not provide any additional supply capacity in the area to support additional growth beyond the current near-term forecast.

Expanding the Horner TS and Transferring Load from Manby TS to Horner TS to Provide Relief to Manby TS

This alternative involves installing an additional bus and transformation capacity at Horner TS, as well as building distribution feeder ties between Manby TS and Horner TS to transfer loads.

There is available space for the expansion at Horner TS and this alternative would not require additional property acquisition. In addition, Horner TS is located in a commercial/industrial area with no residential land uses adjacent to the station.

The estimated cost of this alternative is $70 million, which includes $51 million for the Horner TS expansion plus $19 million for distribution transfers.

There are some challenges with respect to the distribution transfers from Manby TS to Horner TS, related to the crossing of Gardiner Expressway. It is expected that Toronto Hydro will address these challenges in the detailed design and routing of the distribution feeders.

This alternative provides additional supply capacity in the area, and will still enable the connection of new customer demand if it does materialize in the medium to longer term.

New Transformer Station near Manby TS and Distribution Feeder Capacity

This alternative involves building a new transformer station near Manby TS, supplied from the 230 kV transmission system, and new distribution feeder capacity to supply new customer growth and provide capacity relief for Manby TS.

Building a new transformer station will require acquisition of new property, and additional costs related to the high voltage connection to the Richview – Manby 230 kV transmission system.

The estimated cost of this alternative is $88 million, which includes $72 million for a new 100 MVA (90 MW) transformer station and $16 million for distribution load transfers to relieve the existing stations in the area.

Conservation Targeted at Customers in the Area to Provide Relief to Manby TS

Conservation is not considered a technically feasible alternative to provide the necessary relief in time to meet the need.

Conservation targeted at this area would take time to ramp up, but the relief is required today, as evidenced by the station exceeding its capacity rating in historical years.

The assessment of the amount of conservation achievable potential within the affected area is provided in Appendix H.

DG in the Area Supplied by Manby TS

DG is not considered a technically feasible alternative to provide the necessary relief in time to meet the need because the station relief is required today (the station has already exceeded its capacity rating in historical years). The Working Group is not aware of material potential or customer interest in developing DG resources within this area that can meet this need in time.

Status Quo

Doing nothing is not a feasible alternative as it does not provide the necessary relief for Manby TS.

Summary

The least cost alternative to provide capacity relief for Manby TS is to expand the Horner TS by adding a new bus and transformation capacity, and to use distribution feeder ties to transfer demand from Manby TS to Horner TS. This alternative provides additional supply capacity in the area of Horner TS to accommodate future demand growth, while not requiring any additional property. The Horner TS is located in an area that is not adjacent to residential land use and therefore, there is not likely to be local opposition to construction within the station.

A summary of the attributes of the alternatives considered is shown in Table 7-3.

Table 7-3: Summary of Alternatives for Providing Capacity Relief at Manby and Horner TS

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Distribution feeder ties / load transfers	YES	YES	2-3	77	This alternative is subject to a high degree of cost uncertainty due to the distance and number of physical barriers between the stations in the area
Expand existing Horner TS	YES	YES	2-3	70	Provides relief for existing stations and capacity for future growth; no new sites required
New transformer station	YES	YES	3-5	88	Provides relief for existing stations and capacity for future growth; new site needed with longer implementation time
Conservation	NO	N/A	N/A	N/A	Insufficient potential identified to provide the relief required in time
DG	NO	N/A	N/A	N/A	Insufficient potential identified to provide the relief required in time
Status quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.2.4 Providing Capacity Relief for the Richview x Manby 230 kV Transmission Corridor

The Richview x Manby 230 kV reinforcement will be needed by between 2018 and 2021, depending on the rate of demand growth in the coming years. Under a low demand scenario, the loading on these transmission lines remains flat at the capacity limit until 2026 (as shown in Figure 6-14).

The alternatives considered for providing the capacity relief are discussed below.

Building Two New Transmission Circuits between Richview TS and Manby TS

This alternative involves replacing a 115 kV double circuit line with a new 230 kV line on the existing transmission right-of-way between Richview TS and Manby TS (a distance of 6.5 km). The new 230 kV circuits can be arranged in two possible configurations:

- Reconfigure two of the existing Richview x Manby TS 230 kV circuits to "supercircuits" which would use existing line terminations at Richview TS and Manby TS and provide the higher capacity, or
- Separately terminate the new 230 kV circuits at both Richview TS and Manby TS to create a total of six 230 kV circuits between these stations. This provides the required higher capacity and increased reliability.

The existing right of way is 100 m wide, and can accommodate the replacement of the 115 kV line with a 230 kV line. The new 230 kV towers would be larger than the existing 115 kV towers. Most of the existing corridor is adjacent to residential land uses.

The estimated cost of this alternative is $19.5 million if the existing circuits are reconfigured as "supercircuits," and $39.5 million if separately terminating the new lines.

Upgrade the Existing Richview x Manby 230 kV Circuits with New Conductors

This alternative involves re-conductoring the existing Richview TS x Manby TS circuits using higher capacity conductors on the existing towers. This will allow the existing infrastructure to carry more power into Manby TS.

The estimated cost of this alternative is $16 million, including the re-conductoring of pairs of circuits at $8 million for each pair.

Since the existing towers can be used with upgraded conductors, this option will result in no visual difference along the transmission right-of way once it is completed.

This alternative does not result in any additional supply reliability to the area.

Installation of 70% Series Compensation

Installation of 70% series compensation at Cooksville TS was reviewed and deemed not technically feasible to meet the need due to the space limitations at Cooksville TS, and the proximity of residential homes to the station which limits the opportunity to expand the station.

The capacitor banks would require 0.6 to 1.5 acres of space which is not present at the station, so additional land would be required.

Conservation

A conservation alternative involves targeting peak demand savings in the areas supplied by Manby TS to reduce peak flows on the existing 230 kV lines. A conservation potential study has validated that sufficient potential exists in the areas supplied by Manby TS to defer the need. The conservation achievable potential for the areas supplied by the Richview x Manby circuits is provided in Appendix H.

Targeted demand response to provide peak demand savings up to 40 MW in the areas supplied by the Richview - Manby 230 kV lines could defer the need by several years, depending on the rate of demand growth in the near-term period and beyond. If the demand grows in line with a low demand scenario, no incremental demand response in addition to the ongoing conservation programs to meet the LTEP targets would be required until the mid-2020s (2026). If demand grows according to a high demand scenario, demand response will be required to curtail the peak demand flows on the Richview x Manby corridor by 2018.

The estimated cost of incremental demand response above the LTEP estimated savings under a low demand forecast scenario is about $7 million, which would result in a deferral of this need to the end of the study period (2036). If demand grows higher than expected, the cost of incremental demand response would be needed sooner, and would cost as much as $8 million to defer the transmission need by five years.

Conservation does not provide the additional security of the infrastructure upgrades.

Distributed Generation

DG can be developed in the areas served by Manby TS to supply part of the demand locally, and reduce the peak flows on the existing transmission lines serving the area. The IESO is aware of proponent interest in developing a district energy facility in downtown Toronto that could provide up to 90 MW of capacity relief for the Richview x Manby transmission corridor.

As an alternative to meet this transmission need, DG in the amount of 40 MW, connected to the Manby TS 115 kV sector (or in parts of southern Mississauga and Oakville also supplied by Richview x Manby transmission), could defer this transmission need until the end of the study period under a low demand forecast scenario. This incremental DG resource capacity would be in addition to the achievement of the LTEP conservation targets.

If the demand grows at a faster rate than expected in the near-term period, DG resources in the amount of 40 MW could defer this transmission need by five years (to 2020). Under this higher growth scenario, additional DG resources would need to be added each year to continue to defer the transmission.

The estimated cost to develop 40 MW of DG resources in Central Toronto is $110 million. There is a high degree of cost uncertainty for DG resources as it depends on the type, size and location of the facilities. It is likely that any such facility would incur higher development costs to meet emissions standards and to integrate the facility into the urban environment.

Smaller DG facilities are generally well accepted by communities. The community acceptance of larger DG facilities in Central Toronto is not known.

Status Quo

Doing nothing is not a feasible alternative as these lines are approaching capacity and action needs to be taken.

Summary

Concurrent with ongoing conservation programming to maintain forecast load levels, it is recommended that a targeted demand response program be implemented in the areas supplied downstream from the Richview x Manby 230 kV facilities, to reduce the loadings on these facilities during peak demand periods. In addition, it is recommended that Hydro One continue detailed design work on the infrastructure alternative to minimize the development lead time required to implement the wires upgrades, in the event that planned conservation and targeted demand response activities do not result in the required capacity relief, or if the demand growths faster than expected.

In addition, opportunities to develop DG resources in the areas supplied by the Richview x Manby 230 kV facilities should be explored. The benefits of siting generation locally, in addition to providing transmission capacity relief, will need to be fully accounted for when making comparisons of cost and technical feasibility to transmission and other alternatives.

Upgrading the existing Richview x Manby corridor will increases the load meeting capability of this 230 kV corridor sufficient to supply the projected load growth in Toronto until beyond the IRRP study period. The detailed engineering design and specification of the transmission option should be completed concurrent to the development of conservation and DG opportunities, so that the infrastructure option is available for implementation with as short as possible of a lead time in the event that it is needed.

A summary of the attributes of the alternatives considered is shown in Table 7-4.

Table 7-4: Summary of Alternatives for Providing Capacity Relief for Richview – Manby 230 kV Corridor

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Two new transmission circuits	YES	YES	5-7	19.5 - 39.5	The lower cost range is in combination with "supercircuiting" the existing circuits, and the higher cost is with new line terminations; this option involves installing larger towers on an existing right-of-way adjacent to homes
Upgrade existing transmission circuits	YES	YES	2-3	16	The feasibility of taking outages to complete this work needs to be determined in a detailed study by Hydro One
Series compensation	NO	N/A	N/A	N/A	Not a feasible alternative
Conservation	YES	YES	1-2	7-8+	Low cost range assumes low demand scenario (provides relief to end of study period), the high cost assumes a median demand scenario (provides five years of capacity relief)
DG	YES	YES	3-5	110	Estimated cost for 40 MW of combined heat and power DG, sufficient to provide relief to the end of the study period under a low demand scenario, and for five years of capacity relief under a median demand scenario
Status quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.3 Medium-Term Alternatives

7.3.1 Providing Capacity Relief for Step-down Stations in the Downtown Area

The alternatives that were considered for capacity relief in the Esplanade TS and Copeland TS area are discussed below.

Completing Phase 2 of the Copeland TS

This alternative involves the installation of two additional transformers and load serving busses at Copeland TS, utilizing the space that is being built into phase 1 to accommodate the expansion.

Toronto Hydro's design for Copeland TS phase 2 includes an additional fifth (spare) transformer and a transfer bus to enable the utilization of the spare and station to station ties for additional security for downtown customers.

The bulk of the high voltage switching facilities are being constructed as part of phase 1 of the project.

The estimated cost for the additional transformers and load serving busses is $46 million.

This option does not require any additional property and the station is being built underground. It is not located adjacent to residential land uses.

Expanding the Esplanade TS

This alternative involves constructing a new building next to the existing Esplanade TS and installing two new transformers and load serving busses and high voltage connection facilities.

The estimated cost for this alternative is $48 million.

The Esplanade TS is located adjacent to residential customers and urban parkland.

Conservation

This alternative involves seeking conservation savings targeted at customers in the area to reduce peak demand.

The assessment of achievable conservation potential indicates that there is not technically enough potential in the area to defer or avoid these station needs, nor does conservation add the physical capability to connect new large customers to the distribution system.

The electricity service needs of a number of future developments in the downtown area, such as West Donlands, East Bayfront, lower Yonge Street, and the Portlands area, exceed any conservation savings potential as these developments represent potential large increases in demand that are not be fully reflected in the demand forecast. The total amount of peak demand savings needed includes the 10 MW reflected in the demand forecast, plus up to 90 MW of additional incremental customer demand due to new commercial and high-rise residential development applications. The 90 MW is in addition to the load forecast data as this estimate is based on more recent information regarding development in the downtown area of Toronto.

The assessment of the amount of conservation achievable potential within the affected area is provided in Appendix H.

Distributed Generation

Given the time required to implement DG resources, DG is not likely to avoid the need for additional station capacity.

Furthermore, DG resources do not add capability to connect new customers to the distribution system (e.g., available feeder positions at the station bus).

DG is therefore not considered a technically feasible option to address this capacity need.

Status Quo

Doing nothing is not a feasible alternative because it does not provide the necessary relief.

Summary

The Copeland TS phase 2 alternative is understood to be the most feasible and economic option because Copeland TS phase 1 is being designed to accommodate the expansion, and it is less costly than the Esplanade TS alternative and is not located adjacent to residential land uses.

Conservation resources, in addition to those being incorporated into Toronto Hydro's 2015-2020 Conservation and Demand Management plan, are not likely to produce sufficient savings in time to meet this need; however, Conservation savings should be pursued on its own merits in downtown Toronto to meet provincial policy goals and to meet conservation targets. In addition, conservation achieved in the downtown core can provide relief for the Richview TS x Manby TS need described in Section 6.2.6.

DG resource development should still be encouraged in the area, but these resources cannot be relied upon to reduce the net demand requirements in the Copeland TS and Esplanade TS area, given the continued growth and high-density development planned to occur in the downtown core and surrounding areas in the coming years.

A summary of the attributes of the alternatives considered is shown in Table 7-5.

Table 7-5: Summary of Alternatives for Providing Capacity Relief for Downtown Transformer Stations

Alternative	Technically Feasible (YES/NO)	Meets Standards (YES/NO)	Time to Implement (YEARS)	COST ($M)	Comments
Copeland TS phase 2	YES	YES	3-5	46	Copeland TS phase 1 is being built with space to accommodate expansion, and is not located next to residential land uses
Expand existing Esplanade TS	YES	YES	3-5	48	Requires expansion of the existing site; cost subject to more uncertainty than Copeland TS
Conservation	NO	N/A	N/A	N/A	Requires demand response targeted within a small area in downtown Toronto; demand from new construction is likely to exceed savings from conservation
DG	NO	N/A	N/A	N/A	DG in sufficient amounts cannot be developed in time to meet the need
Status Quo	NO	N/A	N/A	N/A	Not a feasible alternative

7.3.2 Maintaining Reliability/Security Performance Levels Above Standards

Based on the results of the needs assessment and PRA, there are currently not expected to be any cost-effective transmission system options for improving system security in the Central Toronto Area. Transmission and distribution upgrades that have recently been completed, or are in progress, have already introduced additional redundancy and load transfer flexibility to mitigate reliability/security risks. Examples include the John TS to Esplanade TS cable connection, completed in 2008, and the Copeland TS which is under development. These two investments increase the amount of load that can be transferred in the downtown core to alternate supply sources. Other possible actions for maintaining a high level of reliability/security performance in an urban centre such as Central Toronto include:

- Continuing to increase distribution level station intertie capacity to transfer loads in the event of a loss of a transformer station.
    - Toronto Hydro has been systematically increasing the number of distribution station interties in the Central Toronto Area. This program has long-term reliability/security benefits and should continue.
- Developing DG resources for critical customers such as hospitals with the capability to allow these customers to continue operating in the event of power outages.
- Long-term options for additional transmission facilities into downtown Toronto that will provide additional capacity to supply long-term growth, and additional redundant transmission supply sources to the area.

7.3.3 Other Alternatives for Improving System Resiliency for Extreme Contingencies

The assessment of the impact of extreme contingencies indicated that while the existing transmission system supplying the Central Toronto Area is generally resilient in the event of low-probability, high-impact events, there are measures that can be explored to further improve system resilience in the area. Other possible actions to address the risk of extreme contingencies include:

- Special Protection Systems designed to anticipate and enhance the ability of the system operator to quickly respond to extreme contingencies and system emergencies.
- Continued conservation to reduce loadings on equipment and the amount of load that would need to be restored in the event of an extreme contingency.
- DG resources with the ability to provide grid support and operate as islanded micro-grids to continue to supply critical loads such as hospitals and provide critical services during system emergencies.
- Further coordinated study on extreme weather / climate change adaptation options.

7.4 Recommended Near and Medium-Term Plan

In summary, to address the needs expected to occur within the near-term and medium-term period, the IRRP recommends that the following actions be undertaken immediately:

1. **Reconfigure the tap points of Horner TS on the Richview to Manby 230 kV lines to improve the distribution of loading on the 230 kV system by better balancing the loadings using existing infrastructure (completed by Hydro One in 2014)**

2. Implement Special Protection Systems to address supply security and ensure that reliability standards are met for breaker failure contingencies at the major transformer stations serving Central Toronto (Manby TS and Leaside TS)

It is recommended that Hydro One proceed immediately with designing and implementing SPSs that will ensure that facilities at Manby TS satisfy the reliability standards established for the electric power system as demand continues to increase in the area.

It is also recommended that Hydro One review the feasibility of an SPS to enhance supply security in the event of a similar breaker failure contingency at Leaside TS which can affect load supply to Bridgman TS as a discretional security improvement.

- The SPSs will be designed to prevent the failure of breakers: H1H4/A1H4 at Manby West, H2H3 at Manby East, and optionally L14L15 at Leaside TS, from impacting multiple transmission elements that can propagate customer interruptions beyond a minimum level.
- Considering the immediacy of this need, the development of these options was communicated to Hydro One in a hand-off letter in December 2013.[26]
- The December 2013 letter also identified a number of additional observations for consideration in the design of the SPS to enhance the level of electricity service in the area.

3. Implement area-specific conservation options in order to defer 230 kV transmission line capacity needs

It is recommended that the IESO and Toronto Hydro proceed with planning and implementation of conservation initiatives focused on achieving peak demand savings in the parts of the study area supplied by the Richview – Manby 230 kV transmission facilities that are forecast to approach their capacity limits in the near to medium-term period.

Toronto Hydro's 2015-2020 CDM plan should ensure that the initiatives proposed in the Plan reflect the regional capacity needs identified in this IRRP.

Develop targeted demand response programs designed to reduce electrical demand in the area at peak demand periods. These programs should target small to large scale commercial and

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[26] The letter to Hydro One is available at the IESO website: http://www.ieso.ca/Documents/Regional-Planning/Metro_Toronto/OPA-Letter-Hydro-One-Toronto.pdf

institutional customers, and multi-unit residential and small residential customers in the Central Toronto Area.

Develop a comprehensive evaluation, measurement and verification program to monitor the progress of the conservation savings and to estimate the impact of conservation in addressing the capacity needs identified in this IRRP.

4. Conduct further work to identify opportunities for DG resources within the Central Toronto Area

The IESO will work with stakeholders and DG proponents within the City of Toronto, Toronto Hydro and Hydro One to identify opportunities for implementation of DG resources, including district energy and combined heat and power projects, in the Central Toronto Area.

Procure cost-effective DG resources taking into account needs for provincial generation capacity, local capacity, reliability, system security benefits, and meeting government policy targets for clean and efficient generation.

The incorporation new DG in the Manby TS and/or Leaside TS supplied areas could be an economic solution to provide provincial, regional, and local benefits, given the additional generation capacity needed in the Province by the end of the decade.

5. Proceed with work for increasing transformer station capacity in west Toronto by 2018, and in the downtown core by 2021

It is recommended that Toronto Hydro and Hydro One finalize infrastructure options to provide near-term capacity relief in West Toronto for the Runnymede TS, Fairbank TS, Manby TS and Horner TS. This includes Hydro One developing detailed cost and feasibility assessments for upgrades to the 115 kV transmission lines necessary to support the Runnymede TS expansion. Considering the near-term nature of this need, the recommendation to continue with this work was communicated to Toronto Hydro in a letter in April 2014 (Appendix I).

It is also recommended that Toronto Hydro continue with procurement work on the station expansion in downtown Toronto in the medium-term.

The planning, development and procurement work includes:

- Completing the required Connection Impact Assessments and System Impact Assessments,
- Obtaining required regulatory and environmental approvals,
- Identifying detailed station and line work and associated costs to within a range of accuracy suitable for seeking project commitments; and
- Starting the procurement process for long lead time facilities.

6. Proceed with detailed investigation of the infrastructure options to provide capacity relief for the Richview – Manby 230 kV transmission corridor

To cover the risk of higher growth or lower conservation peak demand impacts related to Recommendation 3, the IESO and Hydro One will conduct detailed investigations of options for providing capacity relief for the Richview TS to Manby TS 230 kV transmission lines. This recommendation is to ensure that these options can be implemented in a timely manner, if or when the transmission is needed, and to keep the infrastructure lead time as short as possible.

In the event that Conservation and incremental demand response resources do not materialize to the extent necessary to defer the transmission alternative, the reinforcement of the Richview – Manby 230 kV corridor will be needed by about 2020.

7. Investigate and implement cost-effective options for enhancing supply security and restoration capability following multiple element contingencies in Central Toronto

It is recommended that Toronto Hydro continue to investigate opportunities for increasing capability on the distribution system to transfer station loads to adjacent stations using distribution inter-station ties.

The distribution ties should be able to transfer station loads to adjacent stations in the event of rare N-2 transmission contingencies that could impact service from 115 kV-supplied transformer stations. This should be part of a medium to long-term strategy of incrementally increasing distribution tie capability over time, for achieving higher supply resilience in response to risk of interruption of station service.

8. Conduct further work to assess options for increasing system resiliency for extreme events

It is recommended that the IESO, Toronto Hydro and Hydro One coordinate the assessment of options for increasing resiliency in preparation for possible widespread system outages resulting from low probability – high impact events, either caused by catastrophic failure of multiple critical system elements or extreme weather events such as ice storms and flooding.

Options for increasing system resiliency include Special Protection Systems, continued Conservation, and DG resources. It is also recommended that further work on the risk and impact of extreme weather events be conducted to enhance the capability to prepare for, and respond to these types of events.

8. Long-Term Needs and Options

In the long term, there is a need for additional transmission capacity to supply the Central Toronto Area from both Manby TS and Leaside TS. This need will arise when the demand growth exceeds the capability of the 115 kV transmission lines that supply the downtown core from Manby West, and the 230/115 kV transformers at both Manby TS and Leaside TS.

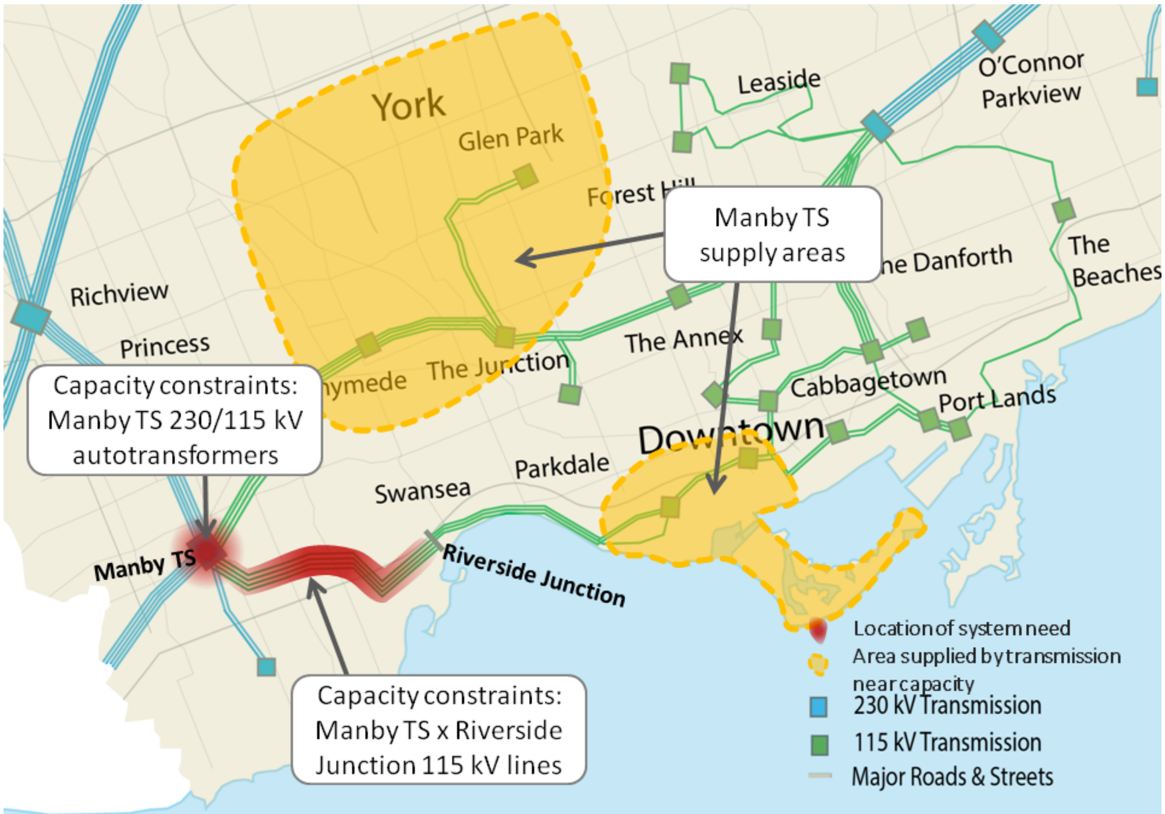
The capacity of the 115 kV transmission lines between Manby TS (Manby West) and the Riverside Junction into the downtown core is forecast to be exceeded as early as 2026 under a high demand scenario. These transmission circuits include the overhead section from Manby TS to Riverside Junction that supply Strachan TS and John TS in the downtown core. The underground section of this transmission corridor, from Riverside Junction to John TS, is being refurbished and upgraded to be capable of operating at 230 kV, although they will continue to operate at 115 kV. Under a forecast scenario that includes the impact of continued planned conservation to reduce electricity demand in the area (e.g., a low demand scenario that assumes achievement of the LTEP conservation targets), the capacity of this section of 115 kV transmission is not expected to be reached until 2031.

In addition to the 115 kV transmission lines, the 230/115 kV transformer capacity at Manby TS is forecast to be reached by 2031 under a high demand scenario. The total capacity shortfall at Manby TS by the end of the study period is forecast to be up to 50 MW. This shortfall is reduced or eliminated considering the achievement of conservation in managing the overall peak electrical demand in the area. Under a low demand scenario that considers the peak demand impact of achieving the LTEP conservation targets, this need is deferred to beyond the study period (after 2036).

A means of addressing this need is could be through the incorporation of an additional transmission supply point to the area that reduces the reliance on the Manby TS 230/115 kV transformers to meet the peak demand requirements of the area. The incorporation of additional electricity generation facilities in the areas supplied by Manby TS would also reduce the loadings on the Manby TS transformers if the generation could reliably operate during the peak demand period.

The constraints at Manby TS and on the 115 kV transmission described above are shown in Figure 8-1.

Figure 8-1: Forecast Capacity Constraints in the Manby TS Sector in the Long-Term Period



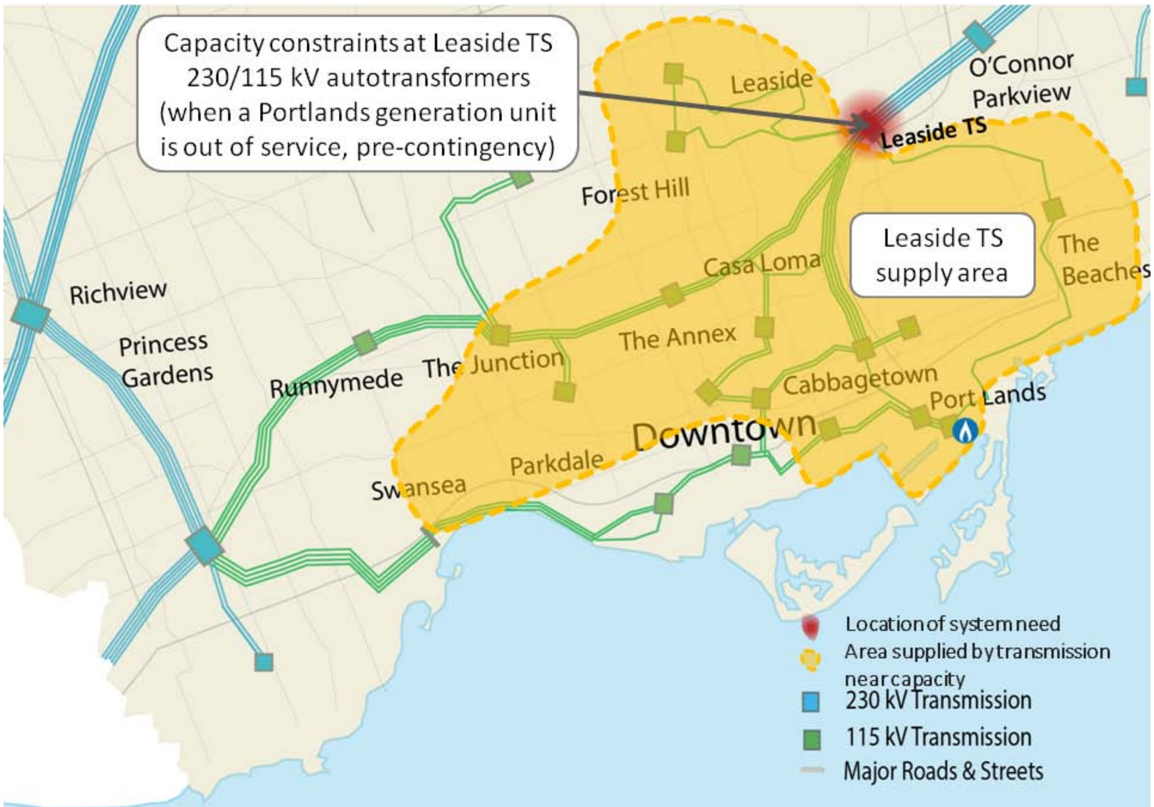
At Leaside TS, the ability to supply long-term load growth is limited by the ratings of 230/115 kV transformers, under a condition when all transmission elements are in service but one unit at PEC is out of service. Under such an N-1 outage at the PEC, both a gas turbine generator and the secondary cycle steam turbine generator will be out of service, and the generation output of the facility drops from 550 MW to 160 MW. This creates a situation, when the demand in the area is high enough (e.g., at peak), in which the Leaside transformers cannot supply the full electrical demand of the area.

This capacity constraint could arise as soon as 2026 under a high demand scenario. The shortfall is forecast to be as high as 200 MW under this scenario. Under a low demand scenario, the shortfall is reduced such that the need is deferred until 2036.

A means of addressing this need could be through the incorporation of an additional transmission supply point to the area that reduces the reliance on the Leaside TS 230/115 kV transformers to meet the peak demand requirements of the area. The incorporation of additional electricity generation facilities in the area supplied by Leaside TS would also reduce the loadings on the Leaside TS transformers if the generation could reliably operate during the peak demand period.

This constraint at Leaside TS described above is shown in Figure 8-2.

Figure 8-2: Forecast Capacity Constraints at Leaside TS in the Long-Term Period



For each of the needs described above, the capacity constraints could be deferred into the 2030s timeframe if the demand growth in the Central Toronto Area is managed through continued conservation achievement. The total amount of conservation peak demand savings under a low demand growth scenario is in the order of 640 MW of savings (550 MW in the 115 kV transmission service area) over the long-term period.

Given the uncertainty related to the timing of these needs, the approach for developing the long-term electricity plan is different than for the near-term plan. For needs arising in the near term, specific actions, programs or projects are recommended to ensure that the preferred solutions are available in time to meet the needs. For the longer term, potential options are identified, but no specific project commitments are made. There is time to explore and develop optional paths for regional electricity system development for the region. Instead of committing specific projects, the focus is instead on identifying possible approaches for meeting long-term needs as they arise in the future.

The approach for the long term is designed to ensure community values and preferences are identified and given consideration in planning, to maintain flexibility with respect to plans, projects and programs, and avoid committing ratepayers to investments before they are needed. This provides additional time to gauge the success and potential of future conservation programs and initiatives, and to test, pilot and, if appropriate, scale up new and emerging technologies. Long-term plans will also need to coordinate with local energy planning activities. Collectively, these steps will lay a foundation for informed decisions in the future.

Another important consideration in developing long-term plans is recognizing the timeframe within which decisions will need to be committed. This involves integrating the projected timing of needs with the expected lead time to bring alternatives into service. To enable fair consideration of all possible alternatives, this latter consideration is driven by the longest lead time among all the possible alternatives. This is usually associated with new major transmission infrastructure, which typically requires five to seven years to bring into service, including conducting development work, seeking regulatory and other approvals, and construction.

Based on the expected timing of the long-term needs in Central Toronto, and the lead times required for infrastructure alternatives, it is expected that, if demand growth turns out higher than is forecast today, decisions on elements of the long-term plan could be required as early as 2019-2020. Current conservation planning targets may result in deferring the timing for these decisions until approximately 2029-2030 (10 years deferral). Additional DG resource integration into the Central Toronto Area could defer this date even further. Therefore, it is recommended that demand growth, impact of conservation, and integration of DG be monitored closely and regularly as part of the implementation of this IRRP. If necessary, the IRRP could be revisited ahead of the 5-year schedule mandated by the OEB's regional planning process.

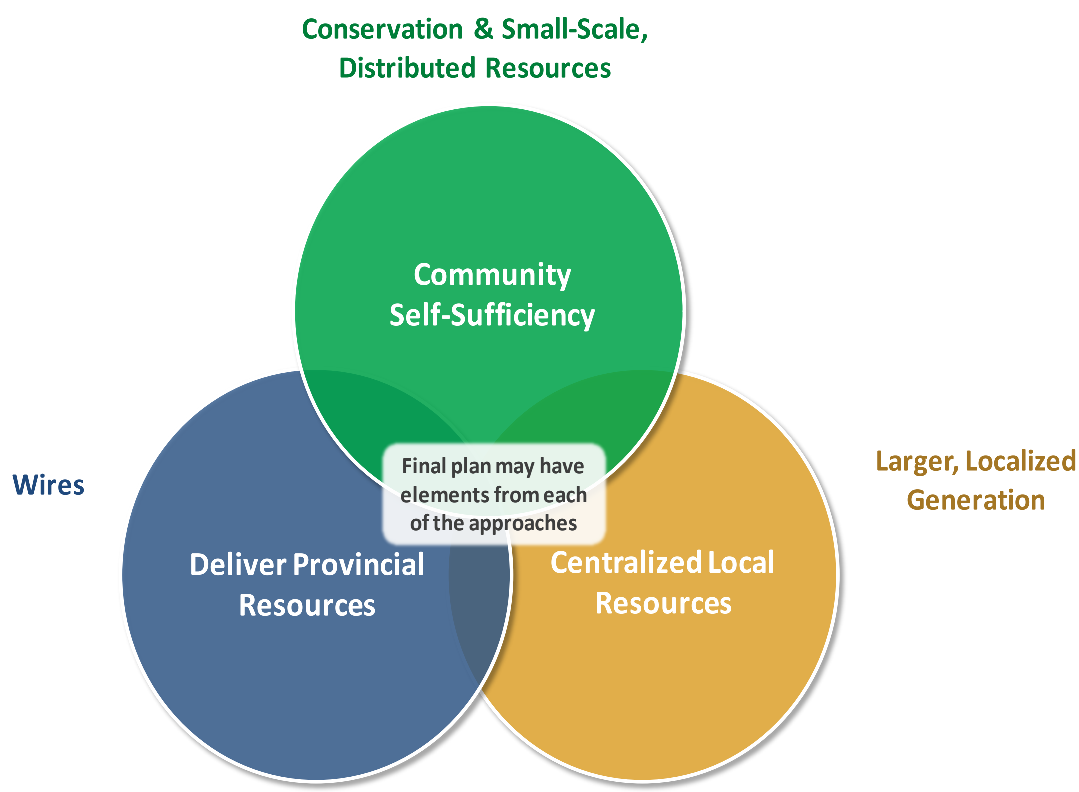
The following sections describe three approaches for meeting the long-term electricity needs of the Region and lay out recommended actions to develop the longer-term plan. It is expected that the regional planning cycle for the Metro Toronto – Central and Northern sub-regions will be aligned for the next planning cycle, and the long-term options for electricity supply will be addressed for the whole Metro Toronto region. Therefore, in the following sections, a City-wide view is presented.

8.1 Approaches to Meeting Long-Term Needs

In recent years, a number of trends, including technology advances, policy changes supporting DG, greater emphasis on conservation as part of electricity system planning, and increased community interest in electricity planning and infrastructure siting, are changing the landscape for regional electricity planning. Traditional, "wires" based approaches to electricity planning may not be the best fit for all communities. New approaches that acknowledge and take advantage of these trends should also be considered.

To facilitate discussions about how a community might envision its future electricity supply, three conceptual approaches for meeting a region's long-term electricity needs provide a useful framework (Figure 8-3). Based on regional planning experience across the province over the last ten years, it is clear that different approaches are preferred in different regions, depending on local electricity needs and opportunities, and the desired level of involvement by customers and the community in planning and developing local energy systems.

Figure 8-3: Approaches to Meeting Long-Term Needs



The three approaches are as follows:

- **Delivering provincial resources**, or "wires" planning, is the traditional regional planning approach associated with the development of electric power systems over many decades. This approach involves using transmission and distribution infrastructure to supply a region's electricity needs, taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, with generation sources typically located remotely from the region. In this approach, utilities (transmitters and distributors) play a lead role in development.
- The **Centralized local resources** approach involves developing one or a few large, local generation resources to supply a community. While this approach shares the goal of providing supply locally with the community self-sufficiency approach below, the emphasis is on large central-plant facilities rather than smaller, distributed resources.
- The **Community self-sufficiency** approach entails an emphasis on meeting community needs largely with local, distributed resources, which can include: aggressive conservation beyond provincial targets, demand response, local renewable, DG and storage, smart grid technologies for managing distributed generation resources; integrated heat/power/process systems and electric vehicles ("EV"). While many of these applications are not currently in widespread use, for regions with long-term needs (i.e., 10-20 years in the future) there is an opportunity to develop and test these options before commitment to specific projects is required. The success of this approach depends on early action to explore potential and develop options; it also requires the local community to take a lead role. This could be through a Community Energy Planning process, or a LDC or other local entity taking the initiative to pursue and develop options.

The intent of this discussion, going forward, is to identify which approach should be emphasized in a particular region. In practice, certain elements of electricity plans will be common to all three approaches, and there will necessarily be some overlap between them. For example, provincially mandated conservation policies will be an element in all regional electricity plans, regardless of which planning approach is adopted for a region. As well, it is likely that all plans will contain some combination of conservation, local generation, transmission, and distribution elements. Once the preferences of the community are made clear, a plan can be developed around the approach that makes the most sense, which will affect the relative balance of conservation, generation, and wires in the plan. Details of how these three approaches could be developed to meet the specific long-term needs of Central Toronto are provided in the following sections.

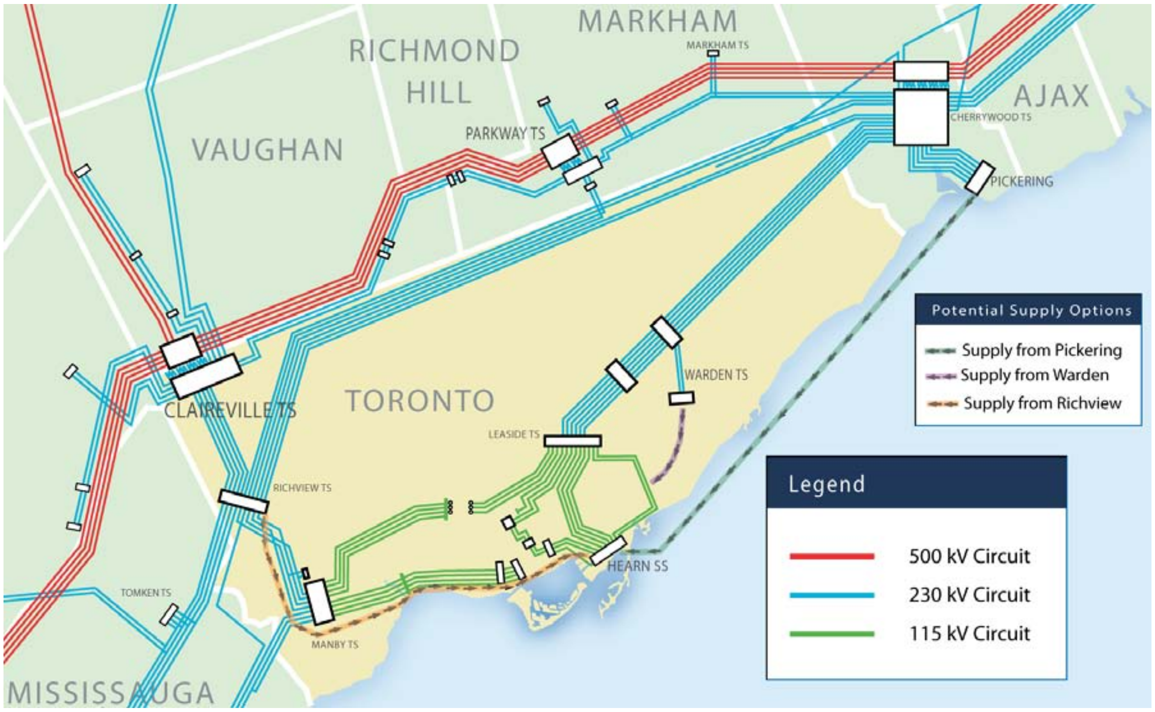
8.1.1 Delivering Provincial Resources

Under a “wires” based approach, the long-term forecast under a high growth scenario could necessitate major new transmission development to deliver power from other major provincial grid sources into the area. Options for other major transmission supply points from the north are limited, and thus a new supply source from the provincial grid under Lake Ontario should be considered as an alternative. Some potential long-term supply sources are shown in Figure 8-4.

Standard planning practices give preference to solutions that make use of existing utility corridors. A section of existing corridor in East Toronto, from Warden TS to the 115 kV system near Leaside TS, could provide the opportunity to upgrade the existing facilities along the right-of-way to diversify the transmission supply network in Toronto.

Another possible wires-based solution involves upgrading the 115 kV supply path from Manby TS into Central Toronto to 230 kV supply. Much of this work has already been completed in anticipation of a possible future switchover from 115 kV to 230 kV. For example, the transmission system from Riverside Junction to Strachan TS, and from John TS to Esplanade TS, is capable of operating at 230 kV. A remaining section, from Manby TS to Riverside Junction, if upgraded to 230 kV, would provide an additional 230 kV source of transmission supply into the area. Bypassing Manby TS en-route to downtown (as shown in Figure 8-4) also provides additional supply diversity into the area (effectively making Richview TS a third major supply point). This section of 115 kV line is identified as requiring a capacity upgrade in the long-term period, and so the opportunity exists to rebuild to 230 kV at that time.

Figure 8-4: Potential Transmission Supply Sources to Meet Long-Term Needs



8.1.2 Large, Localized Generation

Addressing Toronto's long-term needs primarily with large local generation would require that the size, location and characteristics of local generation facilities be consistent with the needs and values of the community. As the requirements are for additional capacity during times of peak demand, a large generation solution would need to be capable of being dispatched when needed, and to operate at an appropriate capacity factor. This would mean that peaking facilities, such as a single-cycle combustion turbine technology, could be more effective than technologies designed to operate over a wider range of hours, or that are optimized to a host facility's requirements.

Opportunities for siting large generation within the City of Toronto are extremely limited due to lack of appropriate land space.

In addition, because local generation would contribute to the overall generation capacity for the province, the generation capacity situation at the provincial level must be considered. Currently, the province has a surplus of generation capacity, and no new capacity is forecast to be needed until the end of the decade at the earliest. This was an additional consideration in ruling out local generation for meeting the near-term needs.

The cost of the generation would depend on the size and technology of the units chosen, as well as the degree to which they can contribute to a provincial capacity or energy need.

8.1.3 Community Self-Sufficiency

Addressing the long-term needs of Toronto under an approach that favours community self-sufficiency requires leadership from the community itself to identify opportunities and deploy solutions. As this approach relies to a great degree on new and emerging technologies, there will be a need to develop and test solutions to establish their potential and cost-effectiveness, so that they can be appropriately assessed in future regional plans.

In Toronto, there is strong community interest in this approach, as evidenced by the municipality taking the lead in identifying and developing energy-based opportunities within the city. Some of these initiatives are described below.

Community Energy Plans

A Community Energy Plan[27] ("CEP") is a comprehensive long-term plan to improve energy efficiency, reduce energy consumption and greenhouse gas ("GHG") emissions. A number of municipalities across the province are undertaking Community Energy Plans to better understand their local energy needs, identify opportunities for energy efficiency and clean energy, and develop plans that better align energy, infrastructure and land use planning within the community.

The City of Toronto has completed a number of Community Energy Plans and others are in progress. While these plans may, more typically, be conducted at the level of the municipality, the size and character of the City of Toronto has resulted in a number of plans being done across the City. The CEPs completed and underway in the City of Toronto include:

- Etobicoke Centre (completed 2008)
- North York (completed 2010)
- Etobicoke – Mimico (completed 2012)
- Scarborough Centre (completed 2014)
- Downtown – Lower Yonge Precinct (in-progress)
- Etobicoke Centre – Six Points Interchange Reconfiguration (in-progress)
- North York – York University (in-progress)

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[27] These plans are sometimes referred to as "Municipal Energy Plans."

Integrated energy planning at the community level provides an opportunity for broader consideration of land-use, development and growth, infrastructure requirements and technology solutions that include:

- Advanced fuel cell technologies
- Energy storage technologies
- Demand response programs – particularly residential and small commercial demand response programs enabled by aggregators
- Aggressive conservation programs targeted at residential consumers and enabled by next-generation home area networks
- Battery electric vehicle storage capabilities, especially for load intensification cluster applications
- Enhanced renewable generation opportunities enabled by next-generation storage technologies
- Micro-grid and micro-generation technologies coupled with next-generation storage technologies
- Combined Heat and Power and district energy opportunities
- Renewed consideration of the Load Serving Entity/aggregator market model

The Working Group recognizes that there are risks associated with the community self-sufficiency approach, with the most crucial being the ability to successfully meet the electricity demand growth needs with new and unproven load management and storage technologies. Other key challenges include demonstrating consumer value, cost recovery certainty for innovative technologies and the risk of asset stranding, risk/reward incentives and technological obsolescence as a factor for asset replacement.

8.2 Recommended Long-Term Plan

The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise. A number of alternatives are possible to meet the region's long-term needs. While specific solutions do not need to be committed today, it is appropriate to begin work now to support decision-making processes in the future.

To address the needs expected to occur in the long-term period, the IRRP recommends that the following actions be undertaken:

1. Establish a Local Advisory Committee to inform the long-term vision for electricity supply in the area

It is recommended that a Local Advisory Committee be established to assess the community values and preferences for the different long-term options, including:

- Delivering provincial resources
- Large, localized generation
- Community self-sufficiency

2. Continue to engage with stakeholders and the community to develop community-based solutions

The IESO will continue to engage with the City of Toronto, energy sector stakeholders, and proponents of community-based energy options to seek opportunities to promote testing, pilot projects and, if appropriate, scale up new and emerging technologies, and to coordinate electricity system planning activities with local energy planning activities

3. Monitor demand growth, conservation achievement and DG uptake

It is recommended that the IESO and Toronto Hydro closely and regularly monitor demand growth, impact of conservation, and integration of DG as part of the implementation of this IRRP.

4. Initiate the next Regional Planning Cycle early, if needed

If changes to assumptions for demand, conservation or DG in the community change, then the IRRP should be revisited and revised ahead of the 5-year planning schedule.

9. Community Aboriginal and Stakeholder Engagement Process

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles. It also activities undertaken to date for the Central Toronto IRRP, and those that will take place to discuss the long-term needs identified in the plan and to obtain input in the development of options.

A phased community engagement approach was developed for the Central Toronto IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the IESO's outreach with Ontarians to determine how to improve the regional planning process, and they are now guiding the plan for further outreach with communities to ensure this dialogue continues and expands as the plan moves forward.

Figure 9-1: Summary of Central Toronto IRRP Community Engagement Process

Creating Transparency:

Creation of Central Toronto IRRP Information Resources

- Dedicated Central Toronto IRRP web page created on IESO (former OPA) website providing background information , IRRP Terms of Reference and list of Working Group members
- Dedicated web page added to Hydro One and Toronto Hydro's websites
- Self-subscription service established for Central Toronto IRRP for subscribers to receive regional specific updates
- Status: Complete

Engaging Early and Often:

Municipal, First Nation & Métis Outreach

- Hosted three meetings with more than 15 participants at each session from the City of Toronto in 2013-14
- Information provided to First Nation communities who may have an interest in the planning area with an invitation to meet
- Invited City of Toronto representatives to stakeholder workshops
- Information provide to Métis Nation of Ontario
- Status: initial outreach complete; dialogue to continue

Bringing Communities to the Table:

Initial Broader Community Outreach

- Discussion workbook developed and tested in **four randomly recruited focus groups** consisting of Toronto Hydro Residential and General Service customers (Three groups between November and December 2013)
- Workbook posted online on September 3, 2014 on IESO, Toronto Hydro and Hydro One websites and promoted in newspaper via advertisements in the Toronto Star, Metroland Community Paper and Metro News
- Stakeholders and community groups engaged through workshops, surveys, webinars, open houses, subscriber lists, bill inserts and traditional and social media channels
- **Four engagement sessions** with General Service and Residential customers in the Central Toronto IRRP study area; between seven and eight stakeholders in each session (September 24 and 25, 2014)
- More than 300 key stakeholders invited to **three workshop sessions** , with between six and 12 participants each
- More than 720 General Service and Residential customers surveyed by phone
- Hosted webinars on September 11 for the public. Webinars were promoted on each Working Group participant's website, via e-blast and through social channels
- Hosted two public open houses in Toronto on September 30 that were promoted through an advertisement in the Toronto Star, Metroland and Metro papers, via social media and e-blasts
- Status: Initial outreach complete

Continued Broader Community Outreach

- Presentations at Municipal Council, First Nation communities & Métis Nation of Ontario as requested
- Webinar to discuss electricity needs, near-term solutions and formation of a Local Advisory Committee (LAC)
- Targetted engagement to discuss the formation of a LAC
- Formation of LAC to discuss long-term needs and local community engagement plans
- Status: beginning in spring 2015, no time limit

Creating Transparency

To start the dialogue on the Central Toronto IRRP planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO (former OPA) website to provide an overview of the regional planning area, information on why the plan was being developed, the plan Terms of Reference, and a listing of the organizations involved was posted on the websites of the Working Group members. A dedicated email subscription service was established for the Central Toronto IRRP where stakeholders could subscribe to receive email updates.

Engaging Early and Often:

In 2011, when the Terms of Reference were signed by the four study partners, the Working Group engaged with Toronto Hydro's sole shareholder, the City of Toronto, and presentations were made on three separate occasions engaging more than 15 city staff members from various departments including Economic Development, Environment and Energy Office, Toronto Water, Parks, Forestry and Recreation, and the Toronto Transit Commission. The purpose of the meetings was to raise awareness about electricity planning needs in Central Toronto, and to discuss supply, the load forecast, specific growth centres, major weather events, long-term needs and stakeholder and community engagement. Key input from these discussions focused on achieving municipal targets for energy efficiency and reducing greenhouse gas emissions.

Bringing Communities to the Table

Due to the nature and size of the sub-region being studied, a multifaceted engagement program was developed. There were primarily three elements to developing and implementing the engagement: establishing background material (the workbook), customer engagement (qualitative research) and telephone surveys (quantitative research).

Key findings from the engagement:

- Most customers are familiar with the electricity system and satisfied with their level of service.
  - 84% of telephone survey respondents are satisfied with their current service
  - 58% of online workbook respondents were satisfied with service during major events
- Cost is a key issue - customers want lower electricity prices and better service
  - When asked "what can be done to improve service, paired with increased reliability," the leading answer to the question was to reduce rates. During the

last 12 months, half of Residential and General Service customers experienced an outage of some kind
    - The Focus Groups understood the need to replace aging infrastructure, but suggested that the system look within for savings before asking customers to pay more
- Cutting down the duration of outages is crucial
    - Much of the engagement focused on how reliability issues affected customers day-to-day – examining customer preference between cost and reliability, and frequency and duration
- The three capacity options presented were not well-known to customers
    - General awareness of Conservation, DG and Transmission and Distribution infrastructure is low, with DG least known
    - When asked about electricity generation in Toronto, solar photovoltaics and CHP are the two option respondents felt most appropriate for use in the Central Toronto Area. Bioenergy and emergency generators were seen as less viable options
    - Overall, customers are supportive of energy conservation and concerned about environmental issues
- Customers think that overall, they are getting good value for money
    - Given the difficult choice between increasing rates or reducing reliability, customers have shown that they will, reluctantly, accept paying marginally more for better service

To further continue the dialogue, a Local Advisory Committee (LAC) will be established as an advisory body to the Metro Toronto regional planning team.[28] The purpose of the committee is to establish a forum for members to be informed, and to advise on the regional planning process. Their input and recommendations, information on local priorities, and ideas on the design of community engagement strategies will be considered throughout the engagement and planning processes. LAC meetings will be open to the public and meeting information will be posted on the IESO website. Information on the formation of the LAC is available on the Metro Toronto Region IRRP main webpage.

Strengthened processes for early and sustained engagement with communities and the public were introduced following the 2013 engagement held with 1,250 Ontarians on how to enhance regional electricity planning. This feedback resulted in the development of a series of

[28] It is expected that future iterations of regional plans for Toronto will be addressed at the city-wide level, consistent with the Metro Toronto Regional Planning Area.

recommendations that were presented to, and subsequently adopted by the Minister of Energy. Further information can be found in the report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum" available on the IESO website.

Information on continuing outreach activities can be found on the IESO website and updates will be sent to all subscribers who have requested updates on the Central Toronto IRRP or for the Metro Toronto Region.

Copies of the community engagement materials are available on the IESO website, and engagement summary reports are provided in Appendix J.

10. Conclusion

This report documents an IRRP that has been carried out for Central Toronto, a sub-region of the Metro Toronto regional planning region, and fulfils the IESO's OEB licence requirement to conduct regional planning in the Metro Toronto region. The IRRP identifies electricity needs in the Region over the period from 2014 to 2036, recommends a plan to address near-term and medium-term needs, and identifies actions to develop alternatives for the longer term.

Implementation of the near-term plan is already underway, with Toronto Hydro developing conservation plans consistent with the Conservation First policy, and with infrastructure projects being developed by Toronto Hydro and Hydro One.

To support development of the long-term plan, a number of actions have been identified to develop alternatives, engage with the community, and monitor growth in the Region, and responsibility has been assigned to appropriate members of the Working Group for these actions. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the IRRP for the Metro Toronto Region.

The planning process does not end with the publishing of this IRRP. The community will be engaged in the development of the options for the long term. In addition, the Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the area, and will produce annual update reports that will be posted on the IESO website. Of particular importance, the Working Group will track closely the expected timing of the needs that are forecast to arise in the medium and long term. If demand grows as forecast, it may be necessary to revisit the plan as early as 2018-2019, in order to respect the lead time for development of alternatives. If demand growth slows or conservation achievement is higher than forecast, the plan may be revisited according to the OEB-mandated 5-year schedule. This outcome would allow more time to develop alternatives and to take advantage of advances in technology in the next planning cycle.

IESO Letter of Comment

Toronto Hydro-Electric System Limited

Renewable Energy Generation Investments Plan

July 20, 2018

ieso
Independent Electricity System Operator

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning,' outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation ("REG") investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Toronto Hydro-Electric System Limited - Distribution System Plan

On June 6, 2018, the IESO received Regional Planning and REG investments information ("Plan") from Toronto Hydro-Electric System Limited ("THESL") as part of their 2020-2024 Distribution System Plan. The IESO has reviewed the Plan and provides the following comments.

FIT/microFIT Applications Received

As of December 31, 2017, THESL's Plan indicates that it has 1087 microFIT projects, totalling 7.2 MW in capacity, and 568 FIT projects, totalling 80.2 MW in capacity, connected to its distribution system.

To date, the IESO's information shows 1161 microFIT projects, totalling 7.5 MW in capacity, and 636 FIT projects, totalling 90.9 MW in capacity. These figures only include FIT and microFIT contracts that are in-service or have received a Notice to Proceed. The renewable energy generation connections information for FIT and microFIT projects in THESL's Plan is therefore substantially consistent with that of the IESO with differences likely a result of when the data was collected.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

THESL is currently a member of a Working Group, with the IESO and Hydro One Networks Inc. ("Hydro One"), and has participated in planning meetings in the development of regional plans for the Toronto Region. The first regional planning cycle for Toronto (Central Toronto Sub-region) was concluded with the publishing of a Regional Infrastructure Plan ("RIP") in January 2016.

In the current regional planning cycle, a Needs Assessment and Scoping Assessment Outcomes Report are complete for the Toronto Region.

- The Needs Assessment was completed in October 2017 and can be found here: https://www.hydroone.com/about/corporate-information/regional-plans/metro-toronto
- A Scoping Assessment Outcome Report and Terms of Reference for the Toronto Region IRRP was finalized and posted in February 2018 and can be found here: http://www.ieso.ca/-/media/files/ieso/document-library/regional-planning/toronto/toronto-scoping-assessment-outcome-report-february-2018.pdf?la=en

An Integrated Regional Resource Plan ("IRRP") is currently underway for the Toronto Region and is expected to be completed in mid-2019. Following the completion of the IRRP, Hydro One is expected to conduct a RIP to complete this cycle of the regional planning process.

Based on a review of the investments proposed in THESL's Plan, the IESO does not foresee a need for co-ordination with other distributors, or transmitters other than Hydro One.

Although the specific investments described in THESL's Plan are not included within the most recent Regional Infrastructure Plan, addressing barriers to connect additional DG within THESL's service area is consistent with regional planning principles. Removing technical barriers to new DG connections can provide lasting benefits to the upstream transmission system by reducing the need, over time, for additional load meeting demands on the high voltage transmission serving the area.

The IESO looks forward to working with THESL on regional planning through the current cycle and appreciates this opportunity to comment on the REG investment information provided as part of its Distribution System Plan.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

C Performance Measurement for Continuous Improvement

C1 Customer Preferences and the Outcomes Framework

In developing its approach to performance measurement, Toronto Hydro considered the OEB's guidance, including the *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRF").[1] A key theme of the OEB's guidance is that utilities should align their investment plans with customer needs, and adopt an outcomes-based approach to tracking their performance.

To remain responsive to customer needs and preferences, and demonstrate continuous improvement in its outcomes-based performance, Toronto Hydro has proposed 15 custom measures that are incremental to measures tracked and assessed by the OEB, for a total of 44 unique measures to be reported annually.[2] This section provides a comprehensive overview of these custom measures for the 2020-2024 plan period. Toronto Hydro's proposed custom measures reflect the utility's understanding of customer priorities and provide a means to demonstrate that value for money will be achieved through the utility's 2020-2024 Plan.

Toronto Hydro's Outcomes Framework is discussed in detail in Exhibit 1B, Tab 2, Schedule 1, and illustrated in Figure 1, below. This framework is aligned with Toronto Hydro's operations, and serves to translate Toronto Hydro's expenditure plan objectives into outcome categories that matter to the utility's customers: Customer Service, Reliability, Safety, Environment, Public Policy, and Financial.

Toronto Hydro's 2020-2024 customer-focused Outcomes Framework was derived through extensive customer engagement efforts (see Exhibit 1B, Tab 3). As discussed in detail in Exhibit 2B, Section E2, Toronto Hydro began business planning by engaging customers and using the feedback received from its customers to assist in shaping the strategic parameters for the planning period.[3]

[1] Ontario Energy Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (October 18, 2012).
[2] These proposed measures will monitor distribution system planning process performance.
[3] The results of Customer Engagement, Phase 1, are discussed in detail in Exhibit 2B, Section E2.3.

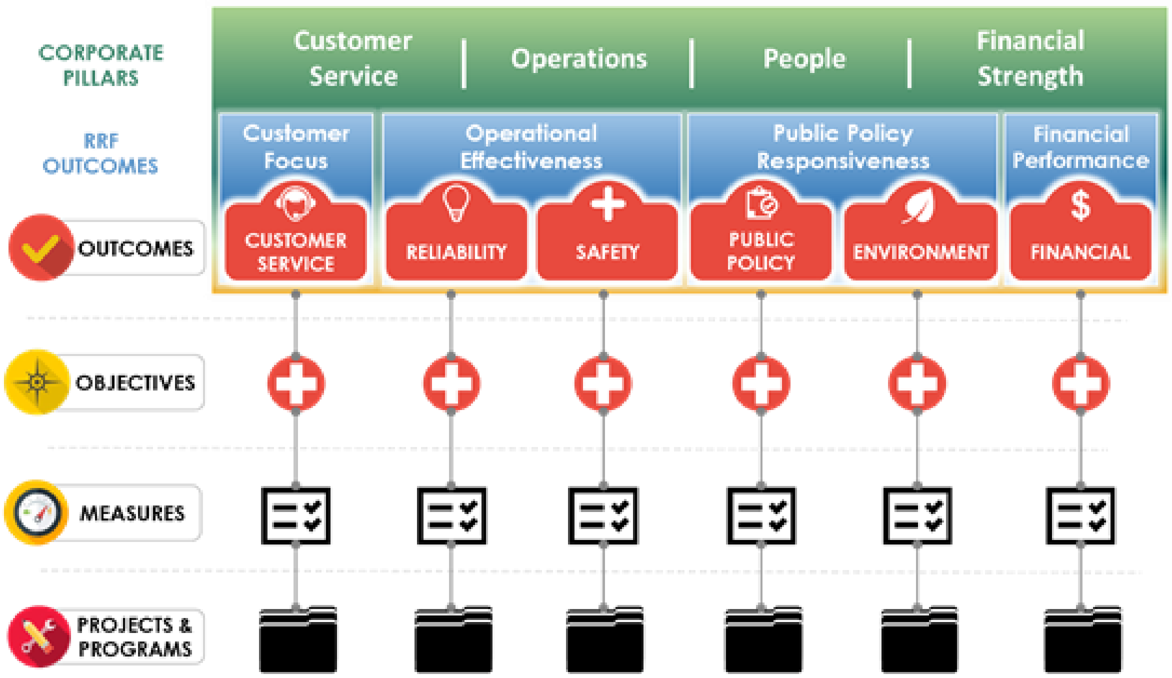

Figure 1: Toronto Hydro's Customer-Focused Outcomes Framework[4]

As detailed in Exhibit 1B, Tab 3, Schedule 1, Appendix A, customer feedback on Toronto Hydro's proposed application was collected in two phases. Phase I was used to develop a list of customer outcomes and identify customer priorities for the utility's planning process. Phase II was used to solicit customer feedback on the utility's proposed plans, and explore trade-offs in relation to specific programs and their associated bill impacts as well as the pacing of proposed investments. Customers were afforded the opportunity to view the cumulative bill impact of their choices and make adjustments, if necessary.[5]

Overall, customers across all rate classes ranked price, reliability, and safety as the top three priorities, with price being ranked higher for low-volume and medium sized customers.[6] Balancing reliability and cost was considered a core issue to be managed. Reliability, in particular, was seen as an asset management issue with a need to balance new investments to meet future demand and

[4] The RRF Outcomes are aligned alongside Toronto Hydro's Outcomes based on the definitions provided by the OEB in the Utility Rate Handbook. It should be noted that Toronto Hydro's Financial outcome includes cost-related components that the OEB would classify within the Operational Effectiveness outcome.
[5] Exhibit 1B, Tab 3, Schedule 1, Appendix A at p.2.
[6] Ibid at pp. 3, 6-7.

replacement of aging equipment to increase reliability.[7] Customers placed high value on safety, both within their homes and workplaces and externally, on the streets and/or in public.[8]

Environment and customer service also emerged as customer priorities. Customers identified concerns relating to the environment as an emerging issue,[9] and placed value on proactive usage and monitoring tools, including those alerting and informing on outages. For a detailed discussion of Toronto Hydro's customer engagement findings, please refer to Exhibit 1B, Tab 3, Schedule 1, Appendix A.

With insight into customers' priorities and preferences, Toronto Hydro developed a customer-focused Outcomes Framework (depicted in Figure 1, above) that aligned with the utility's corporate strategic pillars and the RRF. This transitioned into the lens through which Toronto Hydro developed its business plan, and is reflected in the investment planning decisions made by the utility. Some of these decisions translated into measures in Toronto Hydro's Custom Performance Scorecard, while others appear as priorities at the investment program level. For instance, as discussed in Exhibit 1B, Tab 3, Schedule 1, Appendix A, during an outage, customers value an estimated time of response ("ETOR"). Although Toronto hydro has not proposed ETOR as a custom measure, the utility is working on improving its response communication capabilities during outages through investments proposed as part of Metering (Exhibit 2B, Section E5.4), Control Operations Reinforcement program (Exhibit 2B, Section E8.1), Disaster Preparedness Management (Exhibit 4A, Tab 2, Schedule 6) and Control Centre Operations (Exhibit 4A, Tab 2, Schedule 7).

Overall, Toronto Hydro has developed its capital programs to maintain and improve reliability and safety, meet service and compliance obligations, address load capacity and growth needs, improve contingency constraints, or make necessary day-to-day operational investments. The choices made by the utility reflects a balance between customer preferences, affordability, and prioritized outcomes (as described in Exhibit 2B, Section E2), with the overriding objective of delivering value for money. The utility intends to continue using its Outcomes Framework to engage with customers and to assess and communicate the effectiveness of its plans in delivering value that aligns with evolving customer preferences over time.

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[7] Supra note 5 at p. 11.
[8] Ibid.
[9] Supra note 5 at p. 12.

C2 Toronto Hydro's 2020-2024 Custom Performance Measures

Toronto Hydro is proposing 15 custom measures for the 2020-2024 plan period, see Table 1 below. These measures are incremental to the measures contained in the Electricity Distributor Scorecard ("EDS") and the Electricity Service Quality Requirements ("ESQR"), for a total of 44 unique measures to be reported to the OEB annually. This section provides a comprehensive overview of the outcome measures that are key trackers of the performance of Toronto Hydro's capital plan and supporting maintenance program for the 2020-2024 period.

These measures are reflective of an emphasis on output and results, and should be understood in accordance with their respective challenges. For instance, the Reliability measures should be transposed onto the challenges of operating in a densely populated urban core, using a multitude of complex equipment that is unique in its span and configuration when compared to other Ontario distributors. For a detailed discussion of Toronto Hydro's operating challenges, please see Exhibit 1B, Tab 1 and Exhibit 2B, Section D2.

Each of the 15 custom measures is assigned to an outcome category. Although this assignment means that the measure will be used to track performance under one specific outcome, measures are expected to impact performance in other outcome categories as well. In other words, the custom measures contribute to multiple outcomes. For example, while the Total Recordable Incident Frequency ("TRIF") measure appears in the Safety outcome, it also produces financial benefits (avoided costs), such as a decrease in Workplace Safety Insurance Board premiums, resulting from the utility's safety record. For further details, please refer to Exhibit 4A, Tab 2, Schedule 15. Similarly, the increase in adoption of eBilling measure, currently allotted to measure performance in the Customer Service outcome, also produces financial benefits (avoided costs) given the reduction in paper, printing and postage costs. For more information, please refer to Exhibit 4A, Tab 2, Schedule 14. Lastly, all seven measures under the Reliability outcome contribute to the Customer Service outcome as they are expected to address reliability and connection concerns valued by customers (see discussion above).

In developing targets for these 15 custom measures, Toronto Hydro used the most recent five-year historical data (2013-2017) to set the baseline target for performance during the 2020-2024 plan period. However, given that some of the proposed measures are new (e.g. System Health – Asset Condition (Wood Poles)), the requisite five-year historical data will not be available for 2020-2024 performance target-setting purposes. In such instances, Toronto Hydro will monitor and report its results annually and consider this data in developing potential baseline target to measure future performance.[10]

Toronto Hydro's forecasted measures and targets related to the Custom Performance Scorecard, have been developed on the basis of the proposals, plans and associated rates contained in this Application. To the extent that Toronto Hydro's approvals differ from those it seeks in this Application, the utility would need to re-assess its forecasted performance target for the period. Further, there are risks outside of Toronto Hydro's control which may also affect its ability to achieve performance targets. For instance, the performance in the adoption of electronic billing measure (Customers on eBills) will likely plateau, at some point, due to fact that there will always be a certain demographic, e.g. the elderly with low computer literacy, who will prefer to receive a paper invoice. In such cases, Toronto Hydro's efforts to convert these customers will have a negligible effect on the improvement of its performance in this measure.

Table 1: 2020-2024 Custom Performance Scorecard Measures

Toronto Hydro Outcome	OEB Reporting Category	Toronto Hydro's Custom Measures	Target
Customer Service	**Customer Satisfaction**	Customers on eBills	Improve
Safety	**Safety**	Total Recorded Injury Frequency	Maintain
		Box Construction Conversion	Improve
		Network Units Modernization	Improve
Reliability	**System Reliability**	SAIDI - Defective Equipment	Maintain
		SAIFI - Defective Equipment	Maintain
		FESI 7 System	Improve
		FESI-6 Large Customers	Maintain
	Asset Management	System Capacity	Maintain
		System Health (Asset Condition) – Wood Poles	Monitor
		Direct Buried Cable Replacement	Improve
Financial	**Cost Control**	Average Wood Pole Replacement Cost	Monitor
		Vegetation Management Cost per Km	Monitor
Environment	**Environment**	Oil Spills Containing PCBs	Improve
		Waste Diversion Rate	Monitor

[10] This approach is consistent with the OEB's methodology in the annual Electricity Distributor Scorecard to utilize actual data in order to set baseline targets.

C2.1 Customer Service

Table 2: Customer Service Custom Performance Measure

OEB Reporting Category	2020-2024 Custom Performance Measures	Historical Performance (2013-2017)	Target (2020-2024)
Customer Satisfaction	Number of Customers Receiving Electronic Bills ("eBills")	224,420 (2017 year-end)	Improve

C2.1.1 Number of Customers on eBills

The Number of Customers Receiving eBills measure, within the Customer Service outcome, will track and report on the number of customers who opt-in to receive an eBill, as opposed to a paper bill. This is aligned with Toronto Hydro's efforts to increase the ease and accessibility of its customer billing and account information, consistent with preferences expressed by its customers.[11] For the 2020-2024 plan period, Toronto Hydro plans to increase the usage of eBills to approximately 347,000 customers.

Toronto Hydro prepares over nine million bills annually and offers its customers several delivery options, including standard paper-based bills, eBills, and ePost billing services. As shown in Figure 2, as of the end of 2017, over 224,000 Toronto Hydro customers opted to receive eBills, this is an increase of 250 percent in the last four years. The success of eBilling adoption is attributable to the utility's targeted marketing and education strategies that emphasize the benefits of paper-less billing. By the end of the 2020-2024 period, more than four of every 10 Toronto Hydro customers are expected to receive an eBill, up from 1.7 of every 10 in 2015.

[11] See Exhibit 1B, Tab 3, Schedule 1, Appendix A, at p.4.

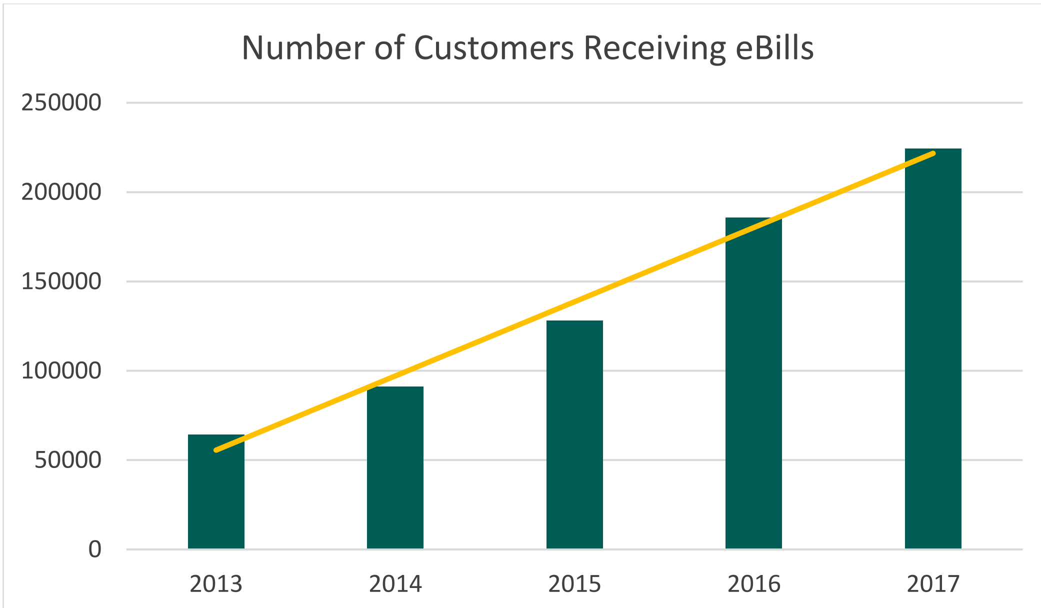


Figure 2: Number of Customers on eBills between 2013 – 2017

As mentioned in the section above, although the Number of Customers Receiving eBills measure is assigned to the Customer Service outcome category, the savings achievable through the success of this measure will contribute to the Financial outcome. This is because eBills are more cost-effective (almost a $1 less) than paper bills. For instance, in 2017, cost-savings amounted to approximately $9.52 per eBilled customer a year. Over the 2015-2024 period, Toronto Hydro expects to save approximately $15.3 million from customers opting into eBills.

In addition, the increase in customer adoption of eBills will also have a positive impact on Toronto Hydro's Environment outcome. Since 2015, Toronto Hydro has reduced its paper usage for billing purposes by approximately 12.4 percent.

Please refer to Metering (Exhibit 2B, Section E5.4), Information Technology (Exhibit 2B, Section E8.4), Preventative and Predictive Overhead Line Maintenance (Exhibit 4A, Tab 2, Schedule 1), and Customer Care (Exhibit 4A, Tab 2, Schedule 14) for discussion of investments that will contribute to the performance of this measure.

C2.2 Safety

Table 3: Safety Custom Performance Measure

OEB Reporting Category	2020-2024 Custom Performance Measures	Historical Performance (2013-2017)	Target (2020-2024)
Safety	Total Recordable Injury Frequency	1.3 recordable injuries per 100 workers	Maintain
	Box Construction Conversion	3,151 box construction poles on the system (2017 year-end)	Improve
	Network Units Modernization	56% with submersible protections (2017 year-end)	Improve

C2.2.1 Total Recordable Injury Frequency ("TRIF")

The TRIF measure tracks the proportion of recordable injuries to hours worked. A recordable injury is defined as any occupational injury or illness that results in an employee experiencing a fatality, lost-time injury, or any other type of injury or illness associated with a restricted work day. Measuring TRIF performance underlies the utility's commitment to health and safety.

The complicated nature and configuration of the utility's assets increase the likelihood of safety-related risks. Examples of operational risks inherent in the execution of Toronto Hydro's DSP are provided in several programs, including Underground System Renewal – Downtown (Exhibit 2A, Section E6.3), Network System Renewal (Exhibit 2B, Section E6.4), Overhead System Renewal (Exhibit 2A, Section E6.5), Corrective Maintenance (Exhibit 4A, Tab 2, Schedule 4), Control Centre Operations (Exhibit 4A, Tab 2, Schedule 7), and Human Resources and Safety (Exhibit 4A, Tab 2, Schedule 15). Mitigating these safety risks require investments in a number of areas, including grid investments addressing Box Conversion and Paper-Insulated Lead-Covered cable, technical training and development programs customized to address specific needs and challenges of Toronto Hydro's distribution system, [12] and a concerted emphasis on safety among Toronto Hydro's entire internal and external workforce. As discussed in the utility's last Rate Application, TRIF figures have decreased significantly since the utility implemented its comprehensive training program in 2006.[13]

[12] Please refer to Exhibit 4A, Tab 2, Schedule 15 for a detailed discussion of Toronto Hydro's internal training programs.
[13] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 4A, Tab 2, Schedule 14, at p. 41.

Figure 3, below, illustrates Toronto Hydro's TRIF performance over the last five years.[14] The utility expects to maintain its safety record during the 2020-2024 plan period.

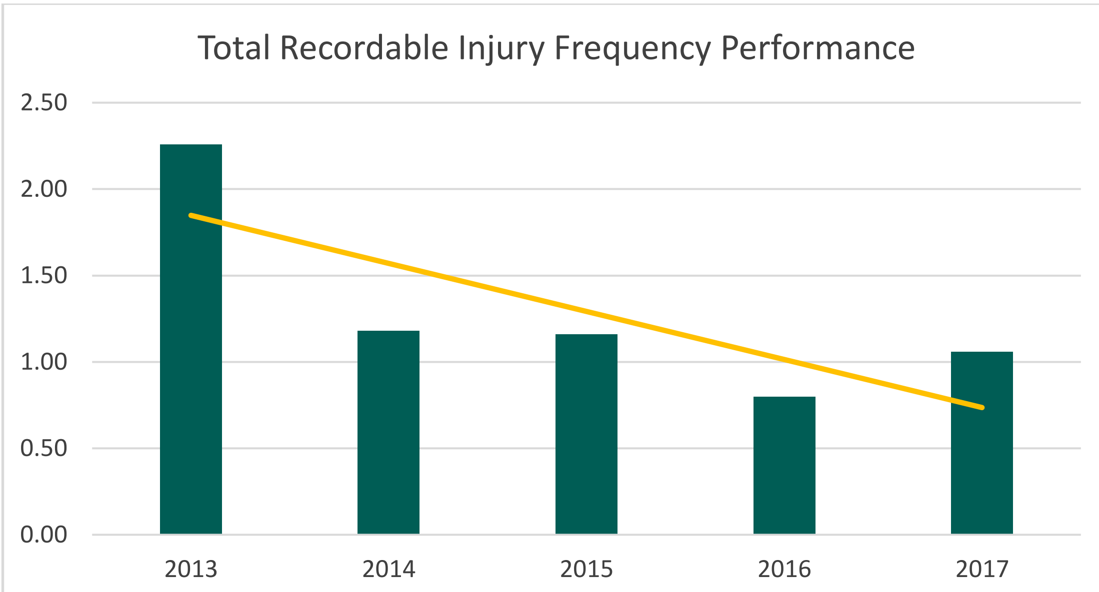


Figure 3: Total Recordable Injury Frequency Performance From 2013 – 2017

A substantial number of Toronto Hydro's capital and OM&A programs will contribute to the performance of this measure. For the proposed 2020-2024 investments driving TRIF performance, please see Area Conversions (Exhibit 2B, Section E6.1), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Underground System Renewal – Downtown (Exhibit 2B, Section E6.3), System Enhancements (Exhibit 2B, Section E7.1), Network System Renewal (Exhibit 2B, Section E6.4), Fleet and Equipment Services (Exhibit 4A, Tab 2, Schedule 11), Work Program Execution (Exhibit 4A, Tab 2, Schedule 10), Control Centre Operations (Exhibit 4A, Tab 2, Schedule 7), and Human Resources and Safety (Exhibit 4A, Tab 2, Schedule 15).

C2.2.2 Box Construction Conversion

The Box Construction Conversion measure tracks Toronto Hydro's performance on the reduction in the number of box construction poles in its distribution system. As discussed in the Area Conversions program (Exhibit 2B, Section E6.1), Toronto Hydro currently maintains overhead pole lines with

[14] The TRIF is normalized to 200 hours- representing 100 workers working a 40-hour week for 50 weeks per year to allow for comparisons between companies utilizing this metric.

legacy framing, referred to as box construction. This type of framing presents several safety risks for employees resulting from the narrow distance between live conductors and inadequate clearances.[15] The congested legacy framing also contributes to poor reliability of the system.

Toronto Hydro has been working on converting feeders with box construction framing over the past five years. Between 2013 and 2017, the number of box construction poles were reduced from approximately 6,400 to approximately 3,200 as at the end of 2017. For 2020-2024, Toronto Hydro is proposing to convert 1,250 or approximately three quarters of the expected 1,600 remaining box construction poles.

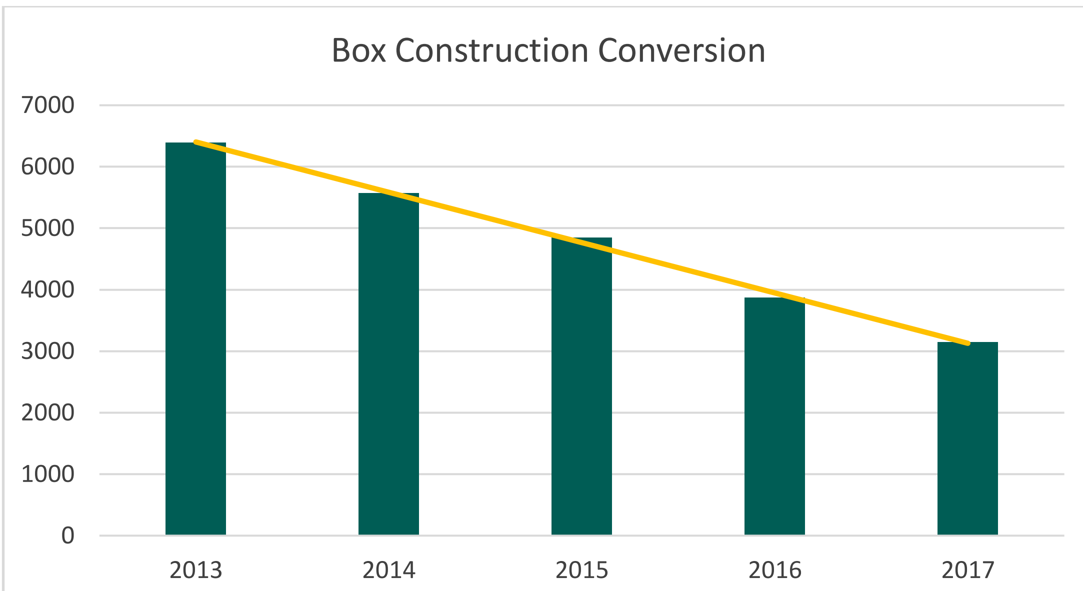


Figure 4: Box Construction Conversion Performance for 2013 - 2017

Replacing approximately three quarters of the remaining box construction poles by 2024 will reduce potential safety risks for crew members dealing with restricted working spaces and improve restoration times.

This measure will also assist in the attainment of Toronto Hydro's Customer Service outcome as the measure will assist in improved connection efficiency, mitigate costs relating to load capacity constraints when connecting new customers to the downtown area, and ensure reliable electricity

[15] Refer to Electric Utility Safety Rule ("EUSR") 129 - Safe Limits of Approach, Canadian Standards Association ("CSA"), and the clearance rules mandated by the Electrical Safety Authority ("ESA").

service. Specifically, the utility expects improvements in this measure will contribute to an increase in the average outage restoration time for 22,700 downtown residential and small business customers.

Please refer to Area Conversions, Exhibit 2B, Section E6.1, for discussion of investments that will contribute to the performance of this measure.

C2.2.3 Network Units Modernization

The Network Units Modernization measure tracks Toronto Hydro's progress on the installation of network units that have resilient submersible protectors. Toronto Hydro has approximately 1,800 network units in its downtown secondary distribution network. These network units are essential as they isolate faults from separate feeders within the network, which protects network equipment, and provides uninterrupted service to downtown load.

A subset of these units are not water tight and can lead to significant corrosion and rust following years of exposure to flooding.[16] Network units also have an outdated design that increase the risk of phase tracking, which can instigate costly and dangerous vault fires with corresponding public and employee safety risks. Toronto Hydro has been removing non-submersible protectors and replacing them with submersible protectors.

During the 2015-2019 period, Toronto Hydro expects to replace approximately 225 non-submersible protectors. Over the 2020-2024 period, Toronto Hydro plans to replace approximately 240 non-submersible protectors, thereby increasing the number of submersible protectors to approximately 75 percent by the end of 2024.

[16] Please refer to Exhibit 2B, Section E6.4 (Network System Renewal), and Exhibit 2B, Section E2 for a detailed discussion of legacy assets.

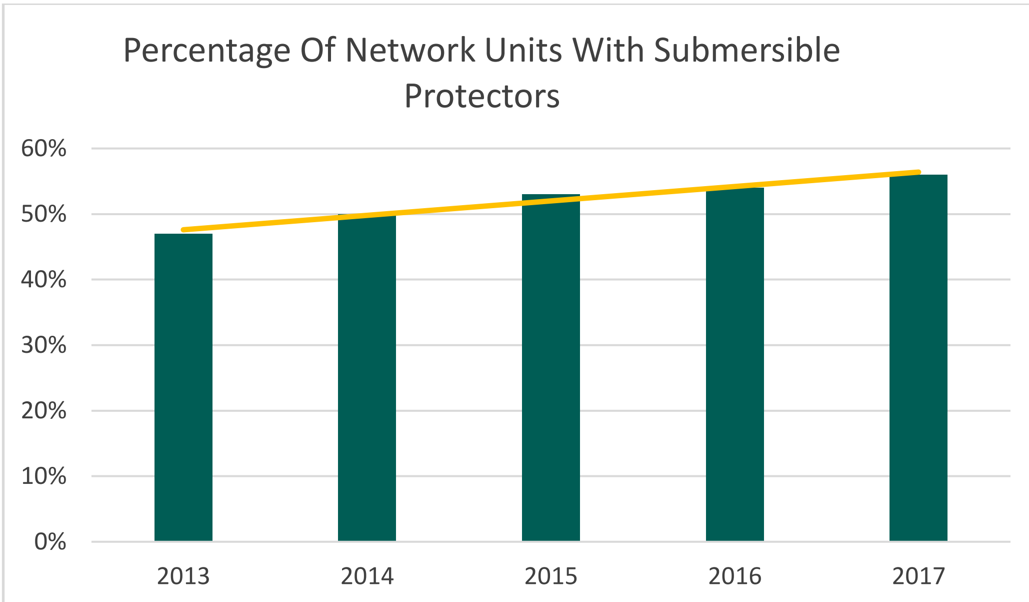


Figure 5: Network Unit Modernization: Percentage of Network Units with Submersible Protectors Performance for 2013-2017

Through this work, Toronto Hydro expects to mitigate public safety and catastrophic equipment failure risks, and help maintain network system reliability in the dense downtown core. Although the Network Units Measure is captured under the Safety outcome, the measure will also affect performance of Toronto Hydro's other outcomes. For instance, the metric will affect the Financial outcome through an expected decrease in costs associated with asset failures, including those resulting from customer interruptions, emergency repairs, and replacement.

Overall, Toronto Hydro anticipates that this program will increase service reliability, improve employee safety, and reduce environmental concerns by mitigated oil leaks. Please refer to Network System Renewal (Exhibit 2B, Section E6.4) for discussion of investments that will contribute to the performance of this measure.

C2.3 Reliability

Table 4: Reliability Custom Performance Measure

OEB Reporting Category	2020-2024 Custom Performance Measures	Historical Performance (2013-2017)	Target (2020-2024)
System Reliability	SAIDI- Defective Equipment	0.45 hours of interruption	Maintain
	SAIFI- Defective Equipment	0.52 hours of interruptions	Maintain
	FESI-7 System	26 feeders (avg.)	Improve
	FESI-6 Large Customers	18 feeders (avg.)	Maintain
Asset Management	System Capacity	17 in 2013 and 13 in 2017	Maintain
	System Health (Asset Condition)-Wood Poles	N/A	Monitor
	Direct Buried Cable Replacement	809 KM as of end of 2017	Improve

C2.3.1 System Average Interruption Duration Index ("SAIDI") & System Average Interruption Frequency Index ("SAIFI") Resulting from Defective Equipment

SAIDI is a measure in hours of the annual system average interruption duration for customers served, not including Major Event Days and Loss of Supply. SAIDI represents the quotient obtained by dividing the total customer hours of interruptions longer than one minute by the number of customers served.

SAIFI is a measure of the frequency of service interruptions for customers served, not including Major Event Days and Loss of Supply. SAIFI represents the quotient obtained by dividing the total number of customer interruptions longer than one minute by the number of customers served.

SAIDI and SAIFI Defective Equipment measures will assess the health performance of the system and highlight the impact of asset failures causing outages. These measures provide insight into the DSP performance as the health of assets is dependent, largely, on the utility's ability to execute its proposed capital and maintenance programs.[17]

[17] Toronto Hydro expects to upgrade its existing Outage Management System to a new Network Management System over the 2018-2022 period. This upgrade is expected to improve the utility's ability to capture interruptions across the distribution system. The utility will monitor the consequences of this upgrade on its reported reliability measures and provided the relevant information to the OEB as part of its annual reporting.

Between 2013 and 2017, outages caused by defective equipment was the main contributor to SAIDI and SAIFI performance.[18] As Figures 6 and 7, below, demonstrate, there was a slight improvement in the level of reliability in these years. This is directly attributable to Toronto Hydro's efforts to address aging and obsolete assets. For a comprehensive discussion of Toronto Hydro's historical system renewal efforts, please refer to Exhibit 2B, Section E2. For the 2020-2024 plan period, Toronto Hydro expects to maintain its performance for these measures.

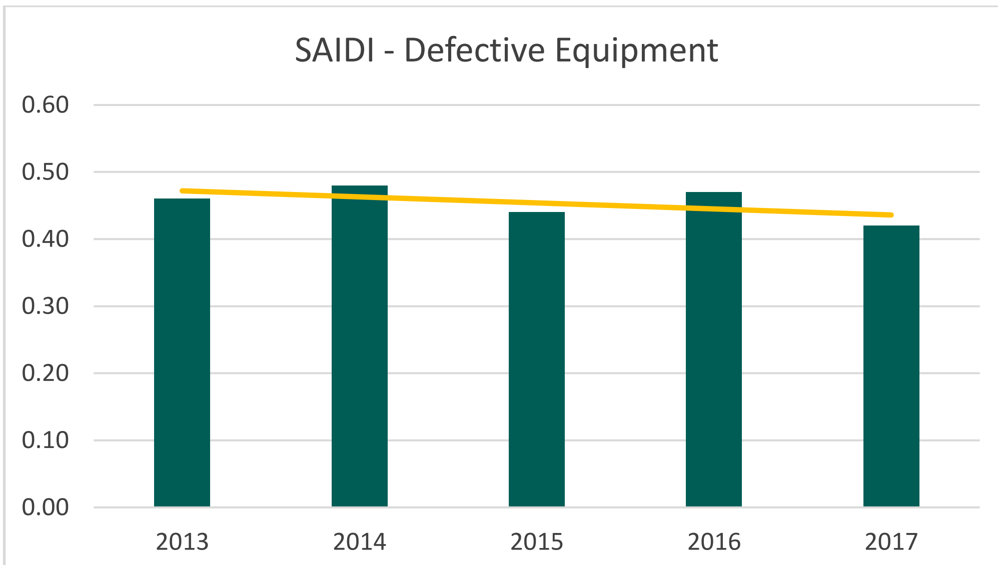


Figure 6: SAIDI (Defective Equipment) Performance between 2013-2017

[18] During this time, defective equipment contributed to 36.3 percent and 44.0 percent of the outages, respectively.

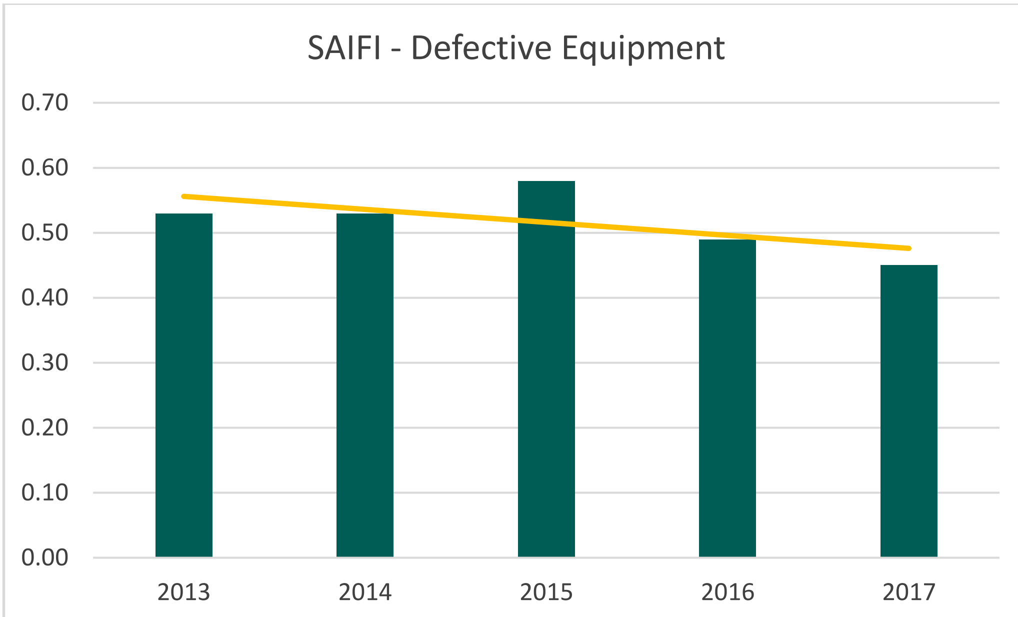


Figure 7: SAIFI (Defective Equipment) Performance between 2013-2017

Toronto Hydro’s proposed investments during the 2020-2024 plan period are aimed at improving asset condition and demographics in order to mitigate reliability risks associated with defective equipment. Reliability results, as measured by SAIDI and SAIFI-Defective Equipment, are expected to decrease if the requisite investments are not made. For more information on system reliability performance and projection scenarios, please refer to Exhibit 2B, Section E2.

A substantial number of Toronto Hydro’s capital programs will contribute to the performance of this measure. For instances of proposed 2020-2024 investments driving SAIDI and SAIFI-Defective Equipment performance, please refer to Load Demand (Exhibit 2B, Section E5.3), Area Conversions (Exhibit 2B, Section E6.1), Network System Renewal (Exhibit 2B, Section E6.4), Overhead System Renewal (Exhibit 2B, Section E6.5), Stations Renewal (Exhibit 2B, Section E6.6), Underground System Renewal – Downtown (Exhibit 2B, Section E6.3), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), System Enhancements (Exhibit 2B, Section E7.1), Stations Expansion (Exhibit 2B, Section E7.4), and the Predictive and Preventative Maintenance and Corrective Maintenance programs (Exhibit 4A, Tab 2, Schedules 1-4).

C2.3.2 Feeders Experiencing Sustained Interruptions (FESI-7/6) - Worst Performing Feeders

FESI-7 System and FESI-6 Large Customer measures track the performance of feeders that, on average, experience the highest number of customer interruptions as measured by Toronto Hydro's reliability metrics.[19] Toronto Hydro will track these measures on an annual system wide-basis, for those feeders experiencing seven or more interruptions (FESI-7 System) and large customers,[20] for those feeders experiencing six or more interruptions (FESI-6 Large Customers).

Between 2013 and 2017, FESI-7 System and FESI-6 Large Customers performance experienced a demonstrable improvement, see Figures 8 and 9, below.[21] For the 2020-2024 plan period, Toronto Hydro expects to improve performance for FESI-7- System measure, and maintain performance for FESI-6 Large Customers.

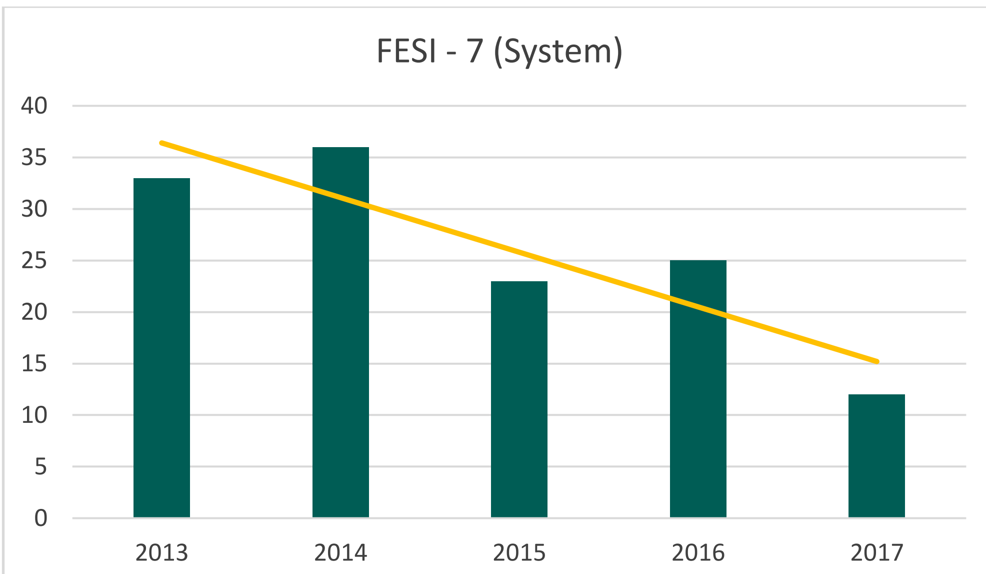


Figure 8: FESI-7 System Performance between 2013 and 2017

[19] These measures exclude interruptions caused by Major Event Days, Loss of Supply, scheduled outages, and station bus-level interruptions on the secondary side of the distribution transformer (e.g. on service wires or secondary bus).
[20] Defined as customers with average monthly peak demand greater than 1 megawatt.
[21] Toronto Hydro considers 2017 to be an outlier. Excluding 2017 results, the average performance for FESI-7- System and FESI-6 Large Customers is 29 and 21, respectively.

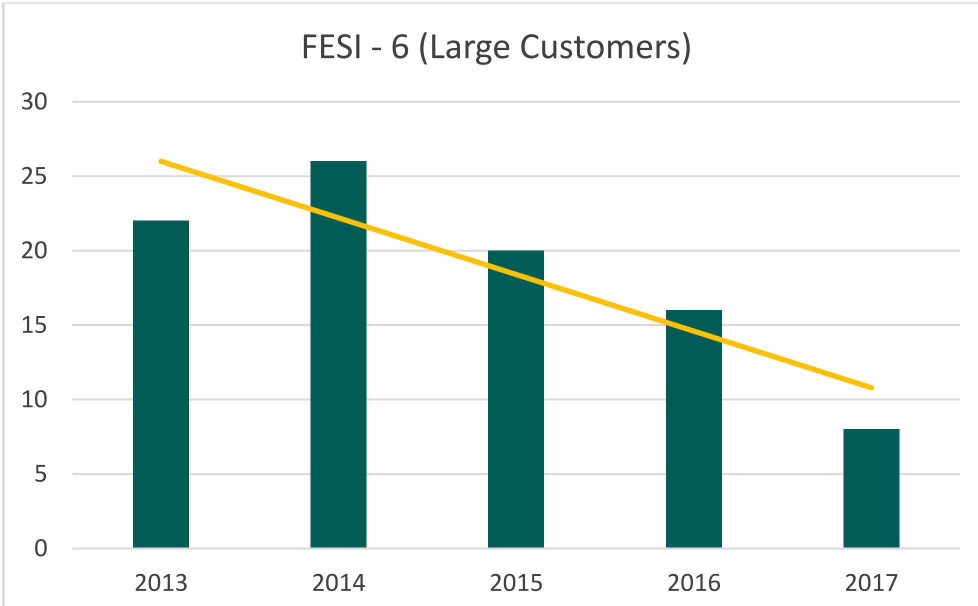


Figure 9: FESI-6 Large Customer Performance between 2013 and 2017

Toronto Hydro has proposed to measure feeders experiencing outages at these thresholds (FESI-7 and FESI-6) to account for customers with lower tolerance for interruptions. For instance, certain customers, such as hospitals, water treatment plants, and commercial manufacturers, have heightened reliability needs. The FESI-7 and FESI-6 measures will allow for the assessment of these nuanced needs and inform Toronto Hydro's planning decisions, targeting investments in areas where performance is substantially lower than the average levels of reliability experienced across the distribution system.

Similar to the improvements in SAIDI and SAIFI, the utility attributes its demonstrable improvement in FESI-7 System and FESI-6 Large Customers to its system renewal investments. For a comprehensive discussion of Toronto Hydro's historical investments, please refer to Exhibit 2B, Section E2.

A substantial number of Toronto Hydro's programs will contribute to the performance of this measure. For instances of proposed 2020-2024 investments driving FESI-7 System and FESI-6 Large Customers performance, please refer to Area Conversions (Exhibit 2B, Section E6.1), Network System Renewal (Exhibit 2B, Section E6.4), Overhead System Renewal (Exhibit 2B, Section E6.5), Stations Renewal (Exhibit 2B, Section E6.6), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Underground System Renewal – Downtown (Exhibit 2B, Section E6.3), System Enhancements

(Exhibit 2B, Section E7.1), and the Predictive and Preventative Maintenance and Corrective Maintenance programs (Exhibit 4A, Tab 2, Schedules 1-4).

C2.3.3 System Capacity

The System Capacity measure tracks potential capacity constraints at the station level by measuring the ability of each station to connect at least one large customer.[22] This measure focuses on the 35 transformer stations that supply power to the City of Toronto. This measure is responsive to the continued City growth, leading to an increase in population density and urban development. For a comprehensive discussion on the state of the distribution system, including its operating challenges, please refer to Exhibit 2B, Section D2.

The System Capacity measure will consider a variety of factors that contribute to capacity concerns, including bus, transformer and feeder capacity and positions. If any of these factors create the inability to connect a large customer to a station, that particular station will be reported as part of this measure.

As seen in Figure 10, Toronto Hydro has reduced the number of stations with capacity constraints between 2013 and 2017. During this period, on average, there were 14 stations displaying capacity constraints. For the 2020-2024 plan period, Toronto Hydro plans to maintain the current levels of system capacity.

[22] Large customer for the purposes of this measure is defined as a customer with a peak load of approximately 10 MVA or higher.

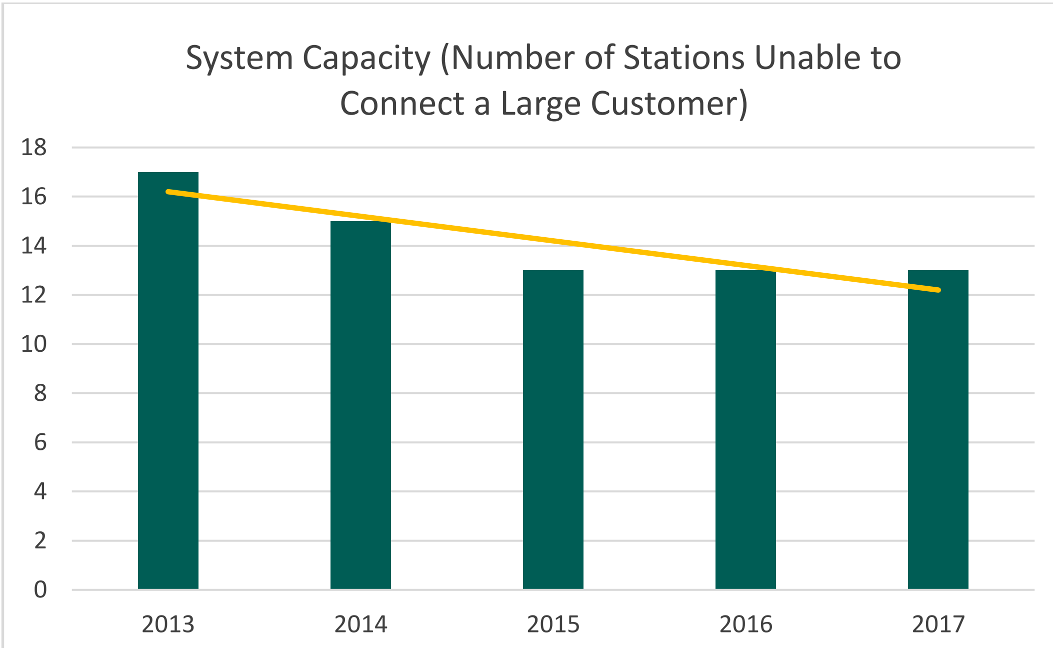


Figure 10: System Capacity (Number of Stations Unable To Connect a Large Customer) Performance for 2013 – 2017

Toronto Hydro's ability to connect customers on time is an existing measure under the OEB's performance tracking framework.[23] The ability to connect a customer to its system is significantly impacted by existing system capacity. Therefore, despite the fact that the System Capacity measure is included under the Reliability outcome, it will impact performance in the Customer Service outcome.

Please refer to Toronto Hydro's proposed investments in Stations Expansion (Exhibit 2B, Section E7.4) for discussion of targeted investments enabling continued and concentrated City growth. Other programs contributing to the performance of this measure include: Stations Expansion (Exhibit 2B, E7.4), Customer Connections (Exhibit 2B, Section E5.1), and Load Demand (Exhibit 2B, E5.3).

C2.3.4 System Health – Asset Condition (Wood Poles)

The System Health – Asset Condition (Wood Poles) measure will track the health of wood poles. Wood poles are critical assets and serve as an indication of overall distribution system health. These

[23] See the Electricity Distributor Scorecard and the Electricity Service Quality Requirements. See Exhibit 1B, Tab 2 for a discussion of how Toronto Hydro has performed on this measure.

assets form a sizeable portion of the utility's assets and are instrumental in ensuring reliability and safety. For instance, weak wood poles can tip over during severe weather events, impacting power supply in the area and posing significant safety risks.

Wood poles are one of two major asset classes for which Toronto Hydro performs an Asset Condition Assessment ("ACA"). ACA data shows that approximately 31 percent of the utility's wood poles have at least moderate deterioration as of 2017. With over 20,000 wood poles in HI3 condition (i.e. "moderate deterioration"), over 11,000 in HI4 condition (i.e. "material deterioration"), and approximately 1,100 in HI5 condition (i.e. "end of serviceable life"), pole replacement will continue to be a significant driver of both reactive and planned investment through 2024. For further details, please refer to Exhibit 2B, Section D2.

The System Health – Asset Condition (Wood Poles) is a new measure, and therefore Toronto Hydro does not have the requisite baseline data to set a target for the 2020-2024 period. The utility proposes to use actual annual data to measure its performance during this plan period.

A substantial number of Toronto Hydro's capital programs will contribute to the performance of this measure. For instances of proposed 2020-2024 investments driving System Health performance, please refer to Area Conversions (Exhibit 2B, Section E6.1), Overhead System Renewal (Exhibit 2B, Section E6.5), Reactive and Corrective Capital (Exhibit 2B, Section E6.7), and the Predictive and Preventative Maintenance and Corrective Maintenance programs (Exhibit 4A, Tab 2, Schedules 1-4).

C2.3.5 Direct Buried Cable Replacement

The Direct Buried Cable Replacement measure will track the number of kilometres of direct buried cable that remains in the distribution system during the 2020-2024 plan period. Customers supplied by feeders containing direct buried cable are more likely to experience lengthy interruptions resulting from increased difficulty in locating and replacing faulty segments. During 2020-2024, Toronto Hydro plans on reducing the presence of direct buried cable by approximately 27 percent.

As shown in Figure 11, as of 2018, Toronto Hydro's underground distribution system contains approximately 800 kilometres of direct buried cable. Of this, approximately 370 circuit-kilometres are of the highest-risk cross-linked polyethylene ("XLPE") type and approximately 70 percent of this cable is currently beyond its useful life. This is expected to escalate to 90 percent by 2024. To prevent reliability from degrading, the utility developed a plan to proactively replace approximately one quarter of the 800 circuit-kilometres (i.e. an estimated 215 circuit-kilometres) of this cable in the

Underground System Renewal – Horseshoe program during the 2020-2024 period, prioritizing the highest-risk neighbourhoods based on cable age, performance, criticality, and adjacency to other assets at risk of failure. For further information on Toronto Hydro's Direct Buried Cable Replacement Plan, please refer to Exhibit 2B, Section E2, and Exhibit 2B, Schedule E6.2.

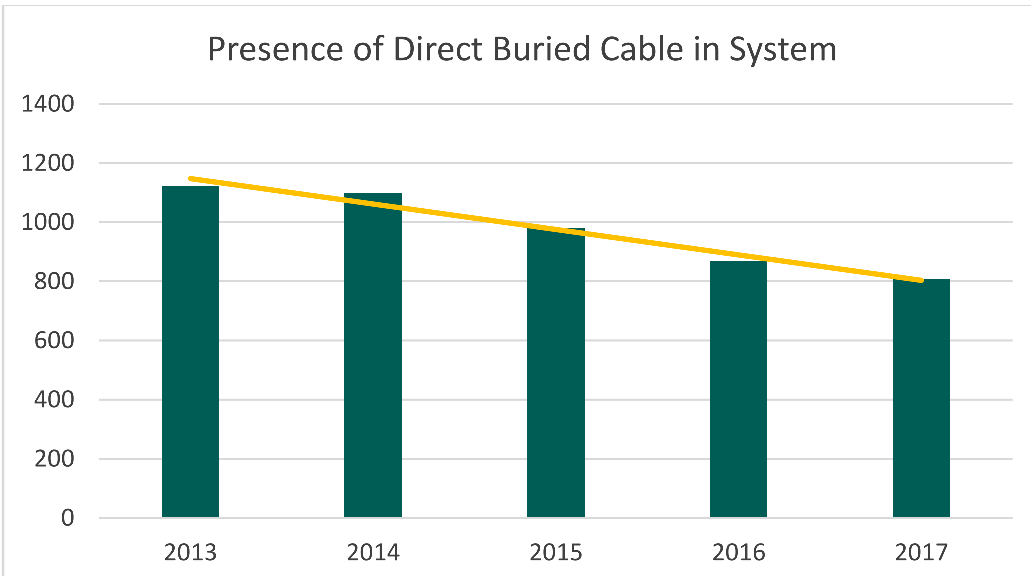


Figure 11: Presence of Direct Buried Cable between 2013-2017

Please refer to Toronto Hydro's Underground System Renewal – Horseshoe program (Exhibit 2B, Section E6.2) for a discussion of proposed investments driving the performance of this measure.

C2.4 Financial

Table 5: Financial Custom Performance Measure

OEB Reporting Category	2020-2024 Custom Performance Measures	Historical Performance (2013-2017)	Target (2020-2024)
Cost Control	Average Wood Pole Replacement Cost	N/A	Monitor
	Vegetation Management Cost Per KM	N/A	Monitor

C2.4.1 Average Wood Pole Replacement Cost

The Average Wood Replacement Cost measure will measure the unit cost of wooden poles installed in the distribution system. As mentioned in the System Health (Asset Condition)-Poles measure description, above, 11,000 wood poles are in HI4 condition (i.e. "material deterioration"), and approximately 1,100 in HI5 condition (i.e. "end of serviceable life"). Consequently, pole replacement will continue to be a significant driver cost driver through to 2024. For further details, please refer to Exhibit 2B, Section D2.

The Average Wood Pole Replacement Cost measure is a new measure and therefore, baseline data does not exist. Toronto Hydro will track performance of this measure using a three-year rolling average, consistent with the methodology applied in the UMS Group Unit Cost Benchmarking Study.[24] This methodology was selected to smooth out year-over-year fluctuations that are likely to occur in the course of utility operations.[25] By way of background, in 2018, UMS Group ("UMS") conducted a Unit Costs Benchmarking Study for Toronto Hydro that assessed its methodology for determining unit costs and benchmarked these costs against its peers.[26] For more information on unit cost metrics, please refer to Exhibit 1B, Tab 2.

A substantial number of Toronto Hydro's capital programs will contribute to the performance of this measure. For instances of proposed 2020-2024 investments driving Average Wood Pole Replacement Cost performance, please refer to Area Conversions (Exhibit 2B, Section E6.1), Overhead System Renewal (Exhibit 2B, Section E6.5), Reactive and Corrective Capital (Exhibit 2B,

[24] UMS Group, Toronto Hydro-Electric System Limited Unit Costs Benchmarking Study, filed as Appendix X to Exhibit 1B, Tab 2.
[25] Ibid at p. 12.
[26] Ibid at p. 8.

Section E6.7), and the Predictive and Preventative Maintenance and Corrective Maintenance programs (Exhibit 4A, Tab 2, Schedules 1-4).

C2.4.2 Vegetation Management Cost per Kilometre ("KM")

The Vegetation Management Cost per KM measure will track the costs of trimming and clearing of vegetation located near overhead feeders to minimize the risk of power interruptions. Vegetation-caused power interruptions are the second highest contributor (following defective equipment) to overall system reliability.

The unit costs for calculating this measure are on a per kilometre basis, determined by dividing the total actual expenditures of the Vegetation Management segment in Toronto Hydro's Preventative and Predictive Overhead Line Maintenance program (Exhibit 4A, Tab 2, Schedule 1) by the total kilometres trimmed.

Given the lack of historical data, Toronto Hydro will track performance of the Vegetation Management Cost per KM measure using a three-year rolling average, consistent with the methodology applied in the Average Wood Pole Replacement Cost measure, see discussion above.

Please refer to Preventative and Predictive Overhead Line Maintenance program (Exhibit 4A, Tab 2, Schedule 1) for a discussion of the proposed investments driving the performance of this measure.

C2.5 Environment

Table 6: Environment Custom Performance Measure

OEB Reporting Category	2020-2024 Custom Performance Measures	Historical Performance (2013-2017)	Target (2020-2024)
Environment	Oil Spills Containing PCBs	9 spills (avg.)	Improve
	Waste Diversion Rate	N/A	Monitor

C2.5.1 Oil Spills Containing Polychlorinated Biphenyl ('PCB")

The Oil Spills Containing PCBs measure tracks Toronto Hydro's progress towards reducing the risk of oil spills containing PCBs. Toronto Hydro has various types of underground transformers (e.g. submersible, padmounted, vault, network), all of which can potentially contain PCB contaminated oil. As of the end of 2017, approximately 3,800 are known to contain, or at risk of containing, PCB contaminated oil greater than 2 ppm. During the 2020-2024 period, Toronto Hydro endeavours to decrease the average PCB-contaminated oil spills by testing or replacing all of the PCB at-risk assets, which will be operating beyond useful life by 2025. For an overview of Toronto Hydro's efforts to reduce the number of PCB-contaminated oil spills, please refer to Exhibit 2B, Section D2.

Figure 12, below, displays the number of oil spills containing PCBs during 2013 and 2017. During this period, the utility experienced, on average, nine PCB-contaminated oil spills. For the 2020-2024 plan period, Toronto Hydro plans to improve its historical performance.

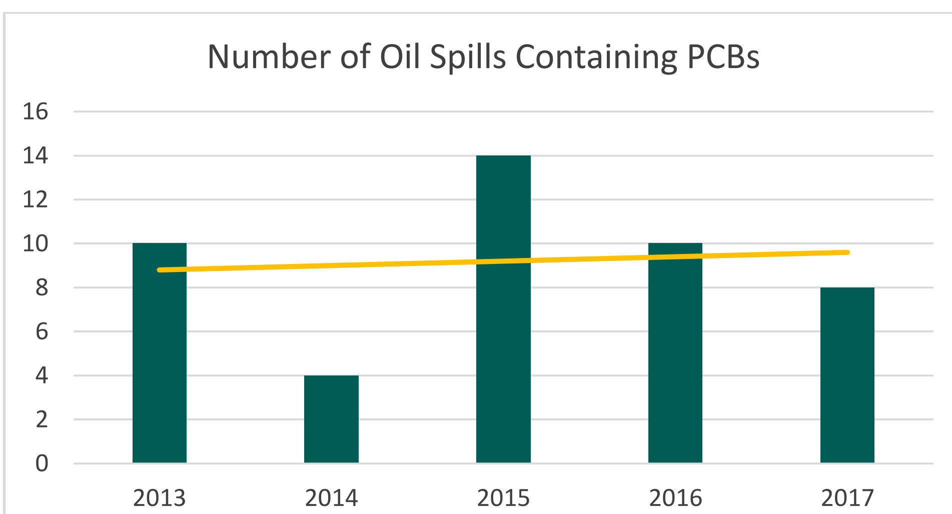


Figure 12: Oil Spills Containing PCBs between 2013-2017

Although a reduction in oil spills containing PCBs is allocated to the Environment outcome, there is a connection to the Public Policy reporting category as PCB-related usage and spills is regulated, in some form, by all levels of government.[27]

For details on the proposed investments driving the performance of this measure, please refer to Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Underground System Renewal – Downtown (Exhibit 2B, Section E6.3), Overhead System Renewal (Exhibit 2B, Section E6.5) and Reactive and Corrective Capital (Exhibit 2B E6.7).

C2.5.2 Waste Diversion Rate

The Waste Diversion Rate measures progress on Toronto Hydro's performance on office and work-site waste diverted from landfills. Waste diversion promotes recycling and reusing materials and presents a number of environmental benefits including reducing waste and lowering greenhouse gas emissions. Toronto Hydro's efforts to divert waste from landfills is a reflection of the utility's corporate leadership in reducing its environmental footprint.

Toronto Hydro has a significant presence in the City of Toronto, with four work centres, 207 stations, four warehouse locations,[28] and approximately 1,500 employees. Waste diversion efforts in the operations of a utility of Toronto Hydro's size can have a significant impact on the environment. The utility actively promotes waste diversion through the following initiatives: removal of employee desk-side garbage bins to encourage a decrease in waste, internal audits of waste collection areas, used furniture donations, and reduction in paper usage. In addition, Toronto Hydro consistently communicates waste and recycling sorting methods to its employees as well as provides an online recycling guide.

During the 2020-2024 plan period, Toronto Hydro plans to install additional organic bins, implement mobile applications to replace paper based forms, work with vendors to reduce packaging, and promote awareness of the recyclability of different types of waste produced in the field.

[27] For instance, the end use deadlines are provided under the federal PCB regulations, PCB Regulations, SOR/2008-273, spills are governed by the provincial Waste Management- PCBs, O. Reg. 232/11. On the municipal level, the Toronto Municipal Code, specifically chapter 681, Sewers, prohibits virtually any discharge of PCBs into the municipal sewages.

[28] One of the locations is managed by a third-party.

For further information on proposed investments driving the performance of this measure, please refer to Reactive and Corrective Capital (Exhibit 2A, Section E6.7), Facilities Management (Exhibit 4A, Tab 2, Schedule 12), and Supply Chain (Exhibit 4A, Tab 2, Schedule 13).

D Asset Management Process

D1 Asset Management Process Overview

Section D of the Distribution System Plan ("DSP") details Toronto Hydro's asset management process, which is the systematic approach the utility uses to:

- Collect, organize, and assess information on its physical assets and current and future operating conditions;
- Assess the utility's business priorities and customer focused goals and objectives in relation to its assets; and
- Plan, prioritize, and optimize expenditures on system-related modifications, renewal, operations, and maintenance, and on general plant facilities, systems and apparatus.

Toronto Hydro's main asset management process is known as the Distribution System AM Process, referenced throughout the DSP as the "AM Process". The utility's processes for non-system (i.e. general plant) assets are fundamentally aligned with the AM Process, relying on many of the same principles, inputs, and evaluative frameworks. However, as there are subtle but relevant differences between the distribution system and general plant processes, Toronto Hydro has included separate, supplemental sections dedicated to the particulars of the asset management processes for general plant assets. Overall, Toronto Hydro has the following major asset management areas:

1) Distribution System AM Process;
2) Information and Operational Technology ("IT/OT") Asset Management; and
3) Facilities Asset Management.

The processes and details for each of these asset management areas are provided in the sections that follow:

- **Section D1** provides an overview of the elements that constitute the AM Process, including the relationship between corporate goals and asset management objectives, and describes Toronto Hydro's roadmap for continuous improvement in distribution system asset management, including enhancements and innovations that have been completed or commenced, with an emphasis on innovations in the period since the OEB's December 2015 decision on Toronto Hydro's 2015-2019 Custom IR application.
- **Section D2** describes the current state of the distribution system based on asset demographics, system configurations and various observable features of Toronto Hydro's

distribution service area, including expectations for the continuing evolution of these features over the forecast period and beyond.
- **Section D3** reviews the policies and practices through which Toronto Hydro optimizes distribution system asset risk, utilization, performance, and costs during the asset lifecycle.
- **Section D4** describes the asset management approach for facilities assets.
- **Section D5** describes the asset management approach for IT/OT assets.

In addition to the major areas listed above, the utility also utilizes a robust approach to the management of its fleet assets, described within the Fleet and Equipment capital program in Section E8.3 of this DSP.

The various asset management processes provide the architecture for long-term, short-term, and maintenance planning functions. Toronto Hydro applied these processes in developing the 2020-2024 Capital Expenditure Plan, described in Section E of the DSP, and the system maintenance plans, described in Exhibit 4A, Tab 2, Schedules 1-5.

Expert Review of Asset Management at Toronto Hydro

During the preparation of its 2020-2024 DSP, Toronto Hydro engaged UMS Group ("UMS") to perform an independent review of Toronto Hydro's asset management practices. UMS has "worked with utilities worldwide in developing and implementing Asset Management capabilities" and is an Institute of Asset Management ("IAM") Endorsed Assessor for ISO 55001 certification. UMS evaluated Toronto Hydro's asset management maturity through the lens of the ISO 55001 framework and UMS's own Strategic Asset Management Framework as they relate to the scope of the OEB's filing requirements for the DSP. UMS found that, across the ISO 55001 domains assessed, Toronto Hydro "exceeds the North American average level of maturity in all areas, reaching into "Best Practice" for some." The full report from UMS is included as Appendix A to Section D of the DSP.

D1.1 Asset Management Objectives and Outcomes

Toronto Hydro's asset management objectives are to a large extent driven by relevant legislative and regulatory obligations and guidance such as the OEB's Distribution System Code ("DSC") and the *Electricity Act, 1998*, including:

- Following good utility practices for system planning to ensure reliability and quality of electricity service on both a short-term and long-term basis;[1]
- "[Ensuring] the adequacy, safety, sustainability and reliability of electricity supply in Ontario through responsible planning and management of electricity resources, supply and demand";[2] and
- "[Protecting] the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service".[3]

Additionally, Toronto Hydro aligns its AM Process with other applicable legislative and regulatory requirements and principles, including the *Ontario Energy Board Act*, *1998*, Toronto Hydro's Distribution Licence, the Standard Supply Service Code, and relevant City of Toronto by-laws.

Beyond its mandated service and compliance obligations, the broader objective of Toronto Hydro's AM Process is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders. This requires continuously balancing near-term customer preferences with the need to ensure predictable performance and costs over the long-term for both current and future customers.

For the purposes of setting strategic outcome objectives and measuring the extent to which those outcomes are met, Toronto Hydro has aligned its AM Process with:

- The utility's strategy for the regulated business, as described in Exhibits 1B, Tab 1 and Section E2 of the DSP; and
- The utility's Outcomes Framework, as detailed in Exhibit 1B, Tab 3, Schedule 1.

Toronto Hydro's corporate strategy and associated business planning processes, including the AM Process, are guided by a set of principles that align with the utility's four corporate pillars. As

[1] DSC, at section 4.4.1
[2] *Electricity Act*, *1998* at section 1.
[3] Ibid.

represented in Figure 1 below, the utility maintains a constant focus on these four pillars – Customer, Operations, People, and Financial – in a balanced way that promotes customer value and a sustainable business. These principles are an essential element in the determination and prioritization of outcomes.

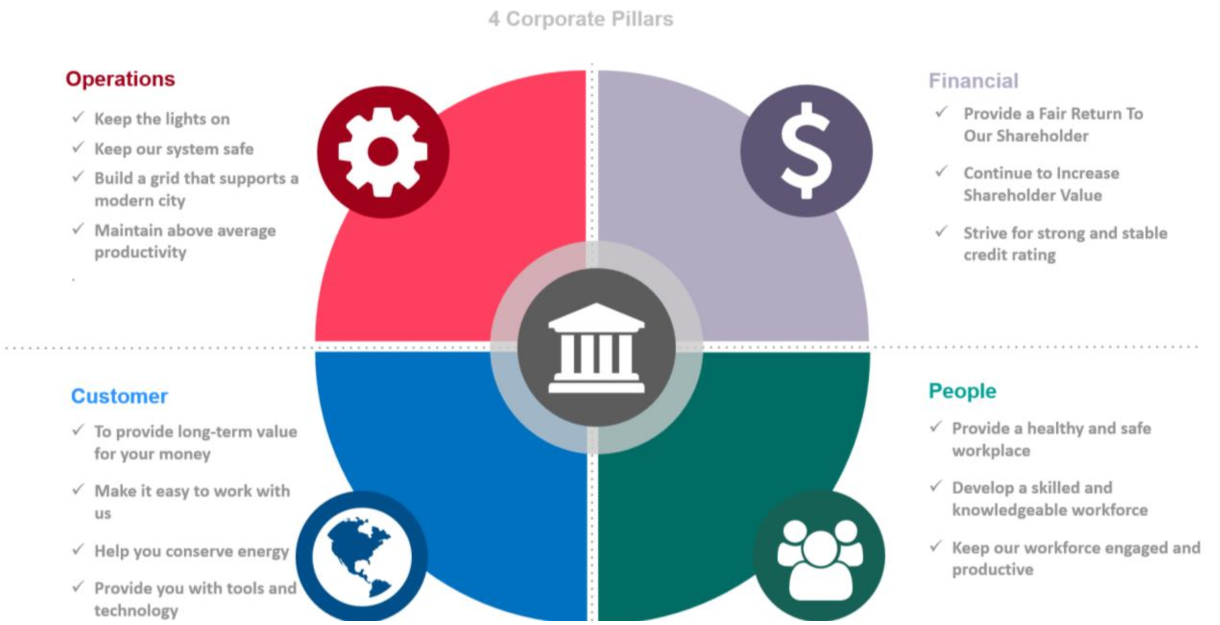


Figure 1: Toronto Hydro's Corporate Pillars

D1.1.1 Introduction of an Enhanced Outcomes Framework

As discussed in Exhibit 2B, Section E2, Toronto Hydro leveraged its Phase 1 Customer Engagement results to develop an enhanced Outcomes Framework for the 2020-2024 planning horizon. This framework serves to translate Toronto Hydro's expenditure plan objectives into outcome categories that matter to the utility's customers. The framework is also aligned with Toronto Hydro's four corporate pillars and the OEB's *Renewed Regulatory Framework* ("RRF") Outcomes. The framework is depicted in Figure 2 in Section E2 and is structured around the following six outcome categories: Customer Service, Reliability, Safety, Environment, Public Policy, and Financial.

Section C of the DSP provides a comprehensive overview of the outcome measures that are most relevant for tracking the performance of Toronto Hydro's capital plan and supporting maintenance programs relative to the utility's customer-focused objectives for the 2020-2024 period.

Toronto Hydro used this Outcomes Framework to develop the strategy and results of its business planning process. The resulting 2020-2024 Capital Expenditure Plan includes measurable objectives that directly or indirectly relate the proposed level of spending in each program to the utility's strategic objective of continuous improvement in each of its six outcome categories (and by extension, each of the four RRF outcomes).

For example, one of the key reliability outcome objectives for Toronto Hydro's System Renewal expenditure plan is to maintain SAIDI and SAIFI at current levels over the 2020-2024 period. The programs in the System Renewal category demonstrate how the planned pace of spending relates to leading indicators of reliability (e.g. asset condition) in a manner that efficiently supports this objective.

The utility intends to continue using this framework to engage with customers and to assess and communicate the effectiveness of its asset management plans in delivering value that aligns with evolving customer preferences over time.

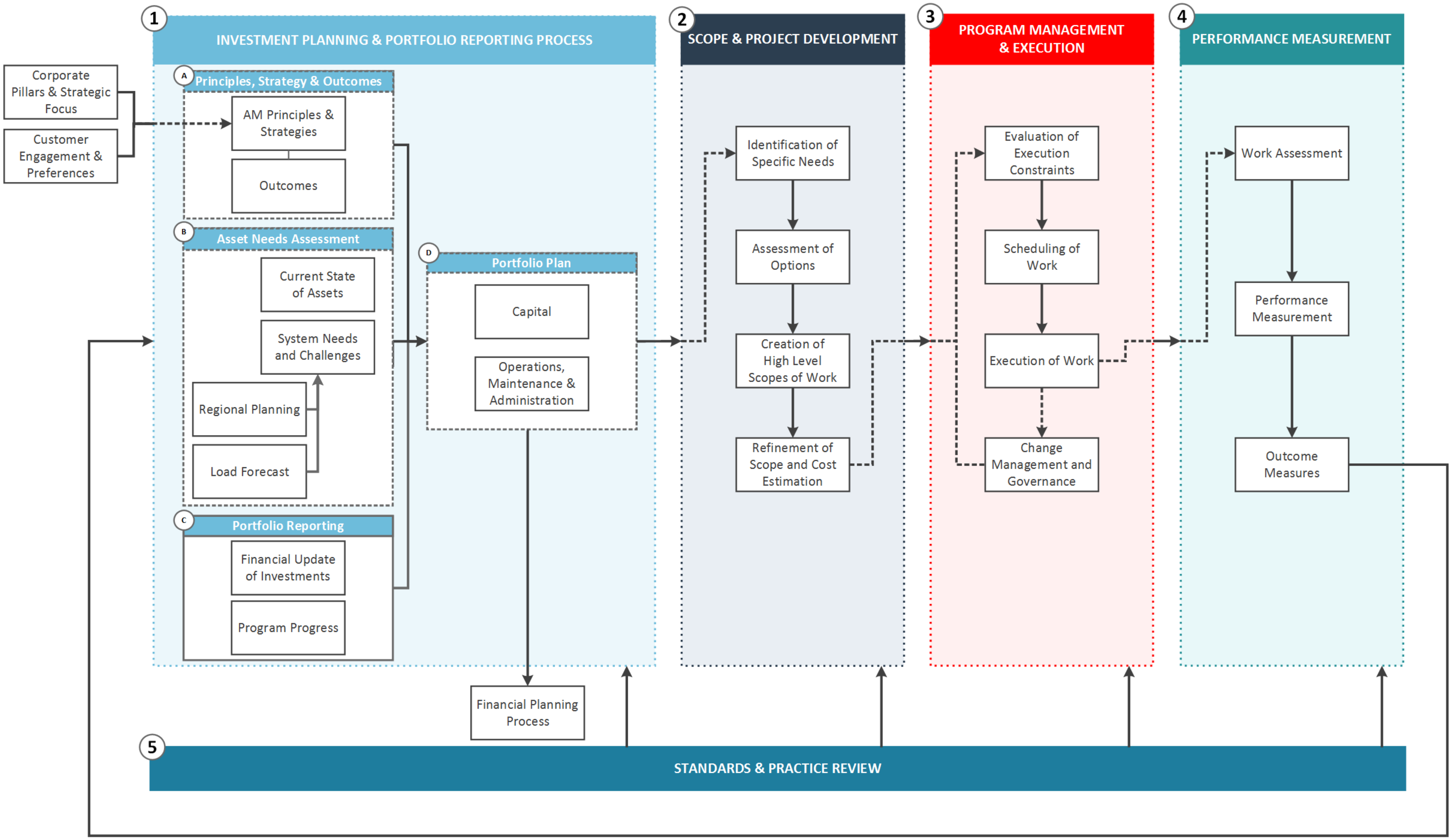
D1.2 Asset Management Process Overview

This section outlines the major elements of the AM Process for distribution system assets, their inter-relationships, and the key inputs and outputs between each element.

The corporate strategy and outcome objectives outlined in the previous section determine the overall direction for decision-making throughout the AM Process. At the same time, the information and performance results generated by the AM Process inform the continuous refinement of corporate objectives, in balance with other considerations such as Customer Engagement and benchmarking results.

Figure 2, below, illustrates the AM Process, consisting of five main components:

- Investment Planning and Portfolio Reporting (“IPPR”) Process;
- Scope and Project Development;
- Program Management and Execution;
- Performance Measurement; and
- Standards and Practice Review.



1 **Figure 2: Asset Management Process Overview**

The following sections outline each main component of the AM Process.

D1.2.1 Investment Planning and Portfolio Reporting ("IPPR") Process

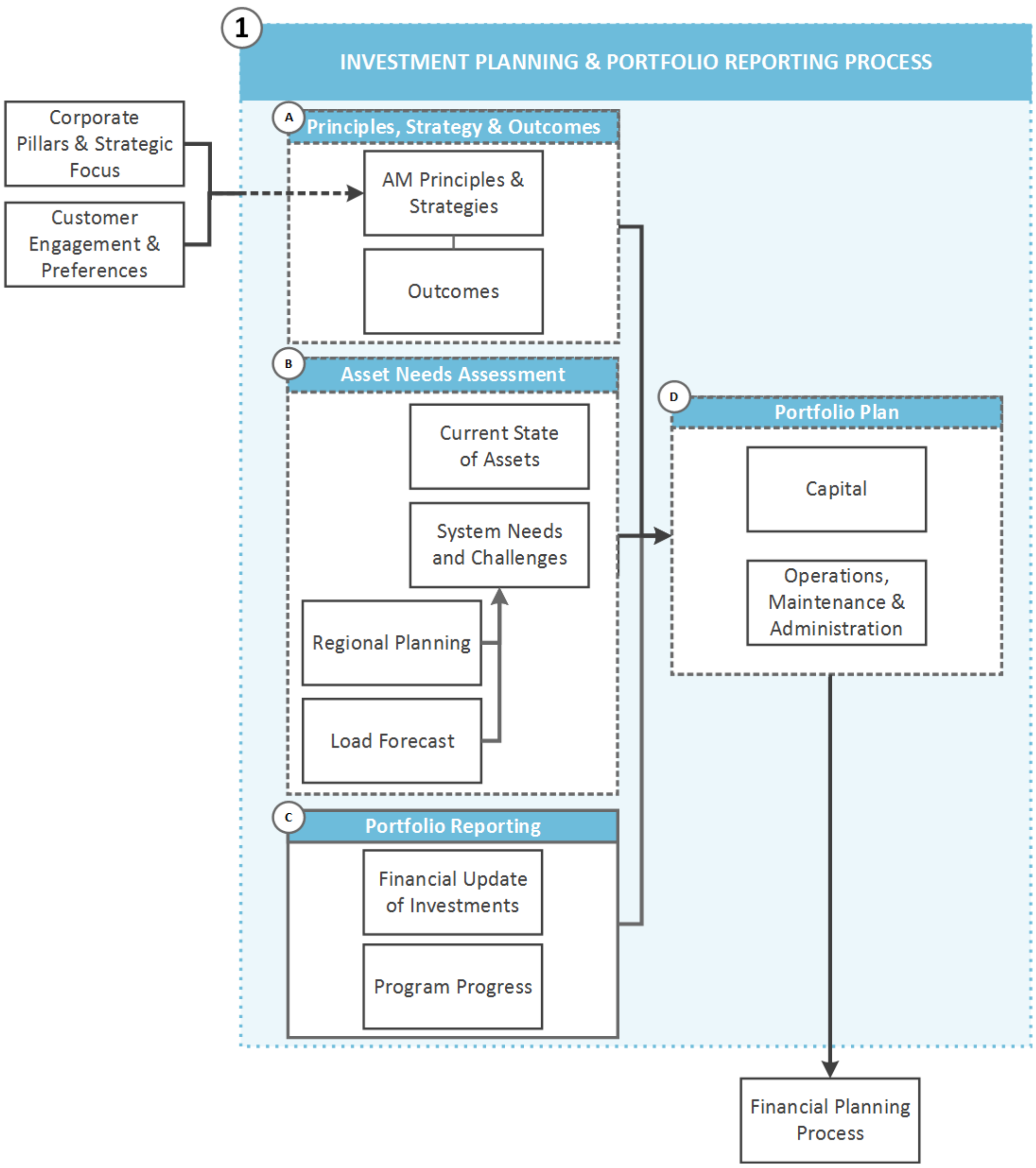


Figure 3: IPPR Process

The IPPR process is Toronto Hydro's system investment planning cycle, which includes both long-term and short-term planning horizons. It is composed of four sets of activities:

- **Principles, Strategies and Outcomes Development:** The IPPR process is guided by Toronto Hydro's asset management principles, strategies, and outcomes. The utility frequently reviews and updates these elements to ensure continuous alignment of asset management decision-making with corporate strategy and customer and stakeholder needs and preferences. These activities are discussed in detail in section D1.2.1.1 below.
- **Asset Needs Assessment:** To determine the types and level of asset investment needed, Toronto Hydro tracks and analyzes the current state of its assets, their performance relative to a wide variety of risk indicators (e.g. environmental, reliability, and safety indicators), and their ability to serve evolving demands from customers and external parties (e.g. bus-level load forecasts and evolving power quality needs). These activities are discussed in detail in section D1.2.1.2 below.
- **Portfolio Reporting:** Toronto Hydro monitors and assesses the progress of its system capital and maintenance programs against annual and longer-term budget, execution, and performance objectives. This helps ensure the utility is cost-effectively executing the DSP while making prudent adjustments in light of new information. These activities are discussed further in section D1.2.1.3 below.
- **Portfolio Planning**: Toronto Hydro uses the outputs of the above three activities to develop capital and maintenance investment plans. These plans are the result of the utility's asset management strategies and outcomes as applied to a combination of the current needs of the system and the current status of ongoing investment activities and accomplishments. Key aspects of the portfolio planning activity include the consideration of alternative investment strategies and the development of both short- and longer-term expenditure plans for each capital program. These activities are described in detail in section D1.2.1.4 below.

Over the last decade, due to the overall effort involved, Toronto Hydro has performed some of the above activities annually (e.g. asset needs assessment), while performing others (e.g. review of asset management strategies and longer-term expenditure plans) less frequently, often as part of a broader planning effort in the lead-up to a rate-setting application. In 2016, with the benefit of an extended five-year rate cycle, Toronto Hydro bundled all of the above activities into a single process that it now executes annually. This change is expected to further strengthen the alignment between: (i) the projects selected for execution within an annual capital plan; and (ii) the utility's overall five-year expenditure plan and outcome objectives. It will also help improve the sensitivity of the planning process to new and evolving information, including ongoing customer and stakeholder engagement, changes in system performance, public policy developments, and other dynamic factors.

The four major activities of the IPPR process are explained in further detail in the following sections.

D1.2.1.1 Principles, Strategies and Outcomes

Figure 4 provides a high-level summary of Toronto Hydro's asset management principles, strategies, and outcomes. The utility reviews and, if necessary, adjusts these components of the AM Process as part of the IPPR process.

Toronto Hydro's overarching asset management *principles* articulate the values that guide the utility's approach to managing its distribution system assets. These principles align with the components of the utility's corporate pillars (e.g. "strive for zero public and employee safety incidents" and "operate the system in a sustainable manner"), while also reflecting the balance between the utility's responsibility as the long-term steward of the system (i.e. system viability) and the needs and preferences of customers, including service quality needs and affordability.

Each of Toronto Hydro's asset management *strategies* is a high-level course of action meant to achieve an objective in relation to each guiding principle. These strategies are based on observed asset risk and performance and emerging challenges. The utility refines and recalibrates its asset management strategies over time to align with customer needs and preferences as identified through formal and informal Customer Engagement (e.g. "Plan investment and maintenance programs to help maintain system average reliability while improving reliability on worst performing feeders […]"). The strategies then serve to guide the utility's decision making with respect to the investment alternatives chosen and the pacing and prioritization of investments in specific programs over a given time period.

Asset management outcomes are the measurable, time-bound, and customer focused results of the utility's asset management strategies. The outcome categories for asset management are the same as those used in planning across all other functions of the utility. Toronto Hydro's 2020-2024 DSP is focused primarily on the outcomes the utility is projecting for the 2020-2024 rate period. Where appropriate, the DSP also includes information necessary to demonstrate the link between investments in the current period and delivery of outcomes over the longer-term (e.g. "Maintain and, where appropriate, reduce asset failure risk – as represented by leading indicators like asset condition – over the 2020-2024 period, supporting stable system reliability and safety outcomes for current and future customers").

PRINCIPLES	STRATEGIES	OUTCOMES
VIABILITY Ensure the long-term viability of the electricity distribution network and meet the customers' electricity supply needs by accommodating growth and evolving consumer and stakeholder needs	**RENEWAL** Ensure stable long-term performance and costs by investing at a pace that will, at a minimum, prevent growing asset performance risk over time **CAPACITY** Ensure station and feeder loading does not exceed specifications and that each station is capable of accommodating anticipated growth and development in Toronto	**RELIABILITY / SAFETY** Maintain and, where appropriate, reduce asset failure risk – as represented by leading indicators like asset condition – over the 2020-2024 period, supporting stable system reliability and safety outcomes for current and future customers **CUSTOMER SERVICE** Continue connecting customers of all types (including distributed energy resources) on time and cost-effectively, without harming system performance for existing customers
PERFORMANCE In alignment with customer and stakeholder needs and preferences, maintain and improve system performance and resiliency, with a focus on delivering performance improvements for customers experiencing poor service	**RELIABILITY** Plan investment and maintenance programs to help maintain system average reliability while improving reliability on worst performing feeders and for customers experiencing poor performance Modify and upgrade equipment standards where appropriate to improve system resiliency to adverse weather events **RENEWAL** Prioritize the replacement of assets with a high risk and consequence of failure **INNOVATION** Pursue innovative technologies that provide customer benefits, with a focus on technologies that can improve the resiliency of the system **POWER QUALITY** Develop solutions to the power quality issues faced by large commercial and industrial customers in Toronto	**RELIABILITY** Maintain system reliability at current levels over the 2020-2024 period while (1) improving the experience for customers with poor reliability and power quality and (2) improving the resiliency of the distribution system
ENVIRONMENT & SUSTAINABILITY Operate the system in a sustainable manner that continuously improves safety and environmental performance	**ENVIRONMENT & SUSTAINABILITY** Take all reasonable actions to mitigate the risk of equipment-related failures and incidents resulting in an adverse effect on the environment Take reasonable steps to gradually reduce greenhouse gas emissions from line losses	**ENVIRONMENT** Endeavour to eliminate the risk of PCB-contaminated oil spills by 2025 Reduce the system's impact on the environment caused by greenhouse gas emissions and oil leaks of all types
SAFETY Strive for zero public and employee safety incidents	**SAFETY** Eliminate all assets and asset configurations that present unacceptable safety risks to employees Develop investment and maintenance plans to reduce all types of public safety risks including those related to contact voltage, downed conductors, and cable chamber lid incidents	**SAFETY** Strive to target zero public and employee safety incidents over the 2020-2024 period Continue to reduce and eliminate public and employee safety risks, for example by removing higher-risk legacy assets from the system within a specific and reasonable timeframe
VALUE & AFFORDABILITY Strive to minimize the total lifecycle costs of the system while continuously delivering customer value	**VALUE-FOR-MONEY** Continuously improve the utility's risk-based approach to prioritizing and pacing investments, with the objective of directing spending to only the highest-value projects Mitigate increases in capital costs by continuously improving planning, estimating, procurement, and project management practices **INNOVATION** Leverage technological innovations that can improve customer value, including technologies that support the deferral of large capital projects	**FINANCIAL** Minimize average rate increases over the 2020-2024 period while continuously improving the value delivered to current and future customers
PUBLIC POLICY & COMPLIANCE Comply with all relevant legislation and regulations and support public policy objectives	**COMPLIANCE** Comply with applicable legislation and regulations **PUBLIC POLICY** Support and adapt to the implementation of public policy as it relates to Toronto Hydro's role in the electricity system (e.g. enabling distributed energy resources)	**SAFETY, ENVIRONMENT, ETC.** Comply with all safety, environmental and customer service regulations and standards over the 2020-2024 period **PUBLIC POLICY RESPONSIVENESS** Respond effectively to public policy during the 2020-2024 period, including by enabling the timely connection of all forecasted renewable generation projects and implementing a Conservation First approach wherever feasible

Figure 4: Summary of Principles, Strategies, and Outcomes

As mentioned above, Toronto Hydro's formal and informal Customer Engagement results influenced the development and refinement of the utility's asset management principles, strategies, and outcomes for the planning cycle that generated the 2020-2024 Capital Expenditure Plan. For further information on Toronto Hydro's Customer Engagement results and how they shaped the plan, please refer to Section E2.3.

The practical alignment of Toronto Hydro's asset lifecycle optimization and risk management practices with its asset management principles, strategies, and outcomes is discussed in detail in Section D3.

D1.2.1.2 Asset Needs Assessment

Toronto Hydro completes a needs assessment of its distribution system to determine the type of investments required. This includes determining the current state of assets, identifying system needs and challenges, and incorporating load forecasts and regional planning results. Further details on these focus areas and how they are used in developing the investment plans can be found in Section D3.2.

Toronto Hydro regularly performs a foundational analysis to understand the current state of the distribution system in terms of asset properties and quantities, asset performance risk (e.g. age, condition, and obsolescence), historical reliability, and asset utilization (e.g. capacity to connect customers and serve peak load).

1. *Asset Properties, Performance Risk, and Historical Reliability*

To assess the properties and quantities of assets and asset performance risk, Toronto Hydro gathers data such as nameplate and locational information from its enterprise systems, including the Geographic Information System ("GIS") and Enterprise Resource Planning ("ERP") system. This data is coupled with information from decision-support systems such as the Interruption Tracking Information System ("ITIS"), which stores historical reliability data, and the Asset Condition Assessment ("ACA"), which provides additional insight into the failure risk of assets based on observable conditions.

Both age and ACA data support Toronto Hydro's assessment of the probability that an asset will fail at a point in time. Asset age is strongly correlated with the probability of asset failure. Its simplicity and availability make it one of the important components of system-wide analysis (e.g. reliability forecasting), particularly for longer time horizons.

The ACA provides additional precision when assessing asset-specific failure risk for certain major asset types. The ACA combines observable asset condition variables (e.g. visible corrosion) with age to generate a health index ("HI") score that relates the overall asset condition to the asset's remaining useful life. This allows the utility to place assets along an asset health continuum, which is then divided into five HI bands (i.e. "HI1" to "HI5"). The bands are used to identify and track the progression of observable asset condition from new or good condition ("HI1") to end-of-serviceable life condition ("HI5"). As assets progress from HI1 to HI5, the risk of asset failure increases. The health of an asset helps Toronto Hydro optimize asset replacement plans by indicating whether an asset has a higher or lower probability of failure than age alone would indicate. The ACA model also allows the utility to project future asset condition at an aggregate population level, which supports effective investment program pacing during the planning process.

Age and ACA are leading indicators of failure and, by extension, the future reliability, safety, and environmental performance of Toronto Hydro's system. As noted above, Toronto Hydro also considers historical reliability – a lagging indicator of performance – in its asset needs assessment. Actual reliability helps to identify areas of poor or worsening performance and is a useful input in project prioritization. Historical reliability can also be a leading indicator of asset failure in specific circumstances. For example, a direct-buried cable that has failed and been repaired is more likely to fail in the future than a cable of the same age that has never failed.

Toronto Hydro also considers the potential consequences of failure when assessing asset needs. For example, a pole-top transformer that is known to use oil containing polychlorinated biphenyl ("PCB"), a prohibited toxic substance, has a heightened consequence of failure and is therefore a higher priority for replacement than an equivalent unit without PCBs.

2. *Capacity and Connections*

Toronto Hydro determines capacity and connection needs through load forecasting, connections forecasting, generation connections forecasting, and the Regional Planning process.

The load forecasting process enables Toronto Hydro to identify capacity availability and anticipated constraints at substations in relation to future load growth. This provides planners with a ten-year view of the system to aid in planning for future needs at the station bus and feeder levels. Further information on the load forecast can be found in Section D3.3.1.1.

The customer and generation connections forecasting processes enable Toronto Hydro to plan for the types and amounts of expenditures required to cost-effectively accommodate all anticipated load and generation customers. Toronto Hydro considers anticipated long-term trends and the number of actual connection applications received in developing these forecasts. See Exhibit 2B, Section D2 for more details.

The Regional Planning Process is an important input to distribution system planning and stations-level planning in particular. Toronto Hydro participates in infrastructure planning on a regional basis to ensure regional issues and requirements are effectively integrated into the utility's planning processes. Toronto Hydro participates in the Central Toronto Integrated Regional Resource Plan, led by the Independent Electricity System Operator, and in the Regional Infrastructure Plan for Metro Toronto Region and GTA North Region, led by Hydro One Networks Inc. Additional details on the Regional Planning process are discussed in Section B2.

3. Other Considerations

In addition to the above system-wide needs assessment considerations, Toronto Hydro assesses and plans for emerging needs and challenges as they arise. For example, the utility has a variety of obsolete legacy assets, such as rear lot distribution lines, that carry higher safety and reliability risks than their modern standard equivalents. These assets present unique risks and replacement challenges that Toronto Hydro addresses through dedicated programs.

For more information on the results of Toronto Hydro's asset needs assessment and a broader discussion of the utility's distribution system, refer to Section D2.

D1.2.1.3 Portfolio Reporting

As part of the IPPR process, Toronto Hydro monitors and reports on the progress of capital programs, which includes program level expenditures, project-specific execution status and project expenditures. The utility monitors changes in system-level outcomes (e.g. average reliability) and the effect of specific programs on specific outcomes (e.g. the reduction in the number of poles in end of serviceable life condition) during the Performance Measurement stage of the AM Process. This performance information is available to Toronto Hydro's planners to assess the benefits of the program to-date and identify necessary pacing and prioritization adjustments to meet objectives or emerging needs in future years.

D1.2.1.4 Portfolio Planning

The final piece of the annual IPPR Process is the development of the plan itself. Toronto Hydro planners use the information from the asset needs assessment and the portfolio reporting process to develop capital investment and maintenance plans that support the achievement of the utility's asset management strategies and outcomes in alignment with customer needs and preferences.

1. Capital Programs

Toronto Hydro develops capital programs that address the needs and challenges of the system in alignment with strategic focus areas and customer preferences. The utility develops the programs to maintain and improve reliability and safety, meet service and compliance obligations, address load capacity and growth needs, improve contingency constraints, and make necessary day-to-day operational investments. These programs are grouped into the following four investment categories based on the investment driver that triggers the work:

- System Access;
- System Renewal;
- System Service; and
- General Plant.

The details of these capital programs can be found in Section E of the DSP.

2. Maintenance Programs

Toronto Hydro's maintenance planning process is designed to assess the condition, extend the life, and maintain the reliability of distribution assets. The utility designs its maintenance programs to extract the maximum value from existing assets. Maintenance typically occurs on set frequencies derived from Reliability Centered Maintenance ("RCM") standards and the OEB's minimum inspection requirements in Appendix B of the DSC.

Toronto Hydro has four major categories of maintenance:

- **Preventative Maintenance:** Typically involves cyclical inspection and maintenance tasks, which emphasize assessing asset condition and preserving asset performance over the expected life of the asset, and maintaining public and employee safety.

- **Predictive Maintenance:** Involves testing or auditing equipment for a predetermined condition (or conditions) to anticipate failures, then undertaking the maintenance tasks necessary to prevent those failures.
- **Corrective Maintenance:** Involves repairing or replacing equipment after a deficiency has been reported, such as actions taken after Emergency Maintenance has restored power. Corrective Maintenance actions may also result from deficiencies discovered during the execution of Preventive or Predictive Maintenance tasks or other planned work.
- **Emergency Maintenance:** Involves the urgent repair or replacement of equipment when the equipment fails, often causing power disruptions to Toronto Hydro customers.

The details of the maintenance programs in these categories can be found in Exhibit 4A, Tab 2, Schedules 1-5.

Toronto Hydro ensures that capital and maintenance programs are coordinated by planning and reporting on both activities within the IPPR process. For example, maintenance programs account for changes associated with capital investment programs, such as new asset classes being introduced or existing asset classes being eliminated.

3. *Pacing and Prioritization*

Toronto Hydro paces its expenditure plans to support the achievement of multi-year outcome objectives (e.g. maintain or improve reliability over a number of years). Pacing decisions are informed by various leading and lagging indicators of risk and performance (e.g. asset condition demographics and reliability projections), and an assessment of various risk mitigation alternatives, as discussed in Section D3.2.

Program expenditures are reprioritized annually based on actual accomplishments and measured performance relative to the multi-year plan, as well as ongoing analysis of evolving system, customer, and stakeholder needs. Toronto Hydro prioritizes projects within and across programs in accordance with anticipated project benefits, estimated costs, and an assessment of execution capabilities and constraints. On this basis, the lowest priority projects are deferred to future years, and the projects that offer the greatest value-for-money relative to the utility’s customer-focused objectives are scheduled for execution.

D1.2.2 Scope and Project Development

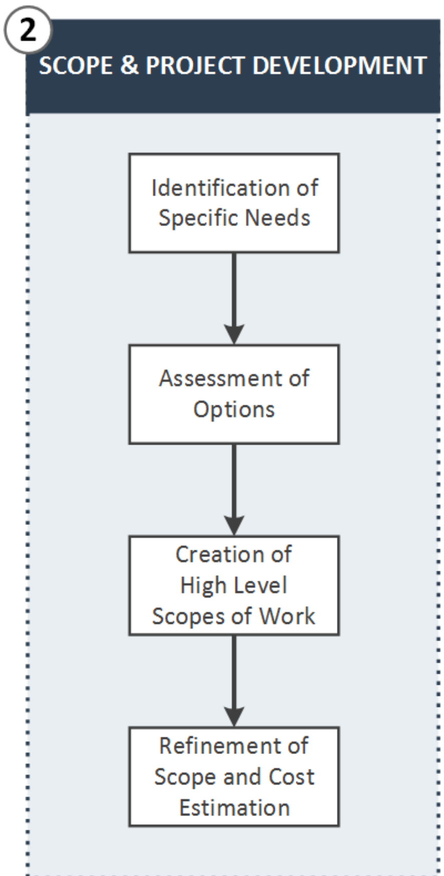


Figure 5: Scope and Development Stage

The scope and project development component of the AM Process involves the development of discrete projects within each investment program. This process involves four components: identification of specific needs, assessment of options, development of high-level project scopes of work ("scopes"), and refinement of scopes and cost estimates.

The investment proposals from IPPR identify and prioritize the assets or issues that require intervention within each capital program. As part of the early stages of scope development, Toronto Hydro prioritizes assets and identifies issues in discrete geographical locations through the use of decision support tools. The utility considers alternatives while developing a scope, which include various engineering options available to address an issue. The utility then evaluates the options with consideration for risks, required performance, customer preferences, effects on third parties, adjacent investment, and reconfiguration opportunities, and the overall costs versus benefits. Finally, the utility selects the preferred option for the specific area or issue being addressed, and collects and summarizes asset information for replacement or refurbishment along with high-level specifications for new assets to be installed as part of a conceptual design. This constitutes the initial scope of work.

The next step is the project development stage, during which a joint team of engineers and designers take the initial scope of work, assess feasibility and field conditions, and refine the cost estimates to achieve a more accurate class of estimate for annual and quarterly budgeting, scheduling, and resource balancing purposes. Toronto Hydro introduced this element of the process beginning in 2014 and 2015 to reduce the range of variances that it was experiencing as complex rebuild projects progressed from high-level budget estimates to the detailed design stage, and to further strengthen the feedback loop between project execution learnings and high-level program planning.[4]

Where appropriate, the project development phase may break an original scope of work into smaller project phases for execution. This could be done for various reasons, including coordination with other work in the system, or to meet external constraints related to the location or the type of work. In the project development phase, the utility also undertakes initial project enabling tasks such as acquiring permits and coordinating with third parties prior to beginning final project design and construction. This helps to avoid design and scheduling uncertainty that can arise later in the process.

[4] Refer to Exhibit 4A, Tab 2, Schedule 9, Section 5 for more details on Toronto Hydro's project development efforts.

D1.2.3 Program Management and Execution

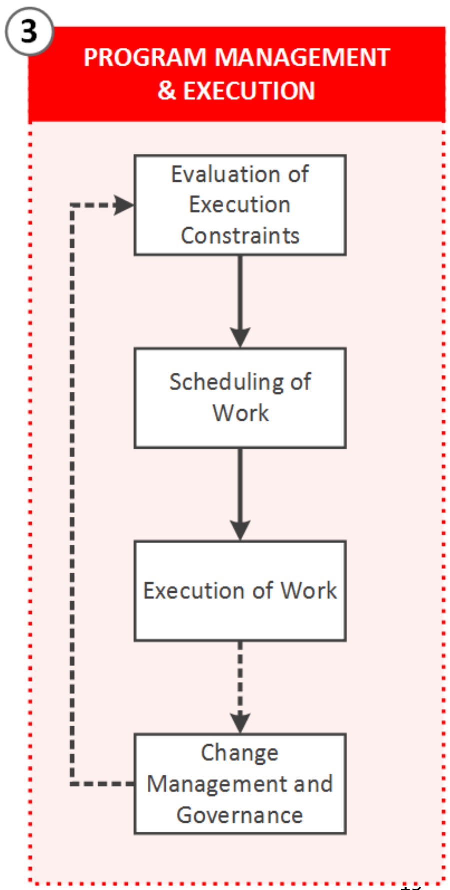


Figure 6: Program Management and Execution Stage

The program management and execution stage of the AM Process involves creating, delivering, and governing an executable work program. The major processes include evaluation of execution constraints, scheduling of work, execution of work, and the change management process that accounts for any required project changes.

The "evaluation of execution constraints" stage considers multiple factors such as available resources, road moratoriums, switching restrictions, and coordination opportunities. Program managers, in coordination with system planners and in alignment with strategic objectives, select a prioritized mix of projects to be executed in a given year. Some of these projects involve assets to be replaced or issues to be resolved that are of the most urgent nature. In order to balance renewal work while addressing emerging needs of the system, engineering staff prioritize projects accordingly.

Once Toronto Hydro develops an execution plan, the actual execution of work is monitored from the detailed design stage through the construction stage. Projects are closely tracked to proactively identify and manage risks that may impact the successful delivery of the planned work.

Toronto Hydro monitors changes to projects through a change management and governance process. This process provides visibility at different levels of the organization as appropriate for the size and strategic importance of a given project. Depending on the magnitude of a required change to a project's cost, schedule, or scope of work, the change may require a detailed assessment of alternatives and formal approval from senior management and the executive team before proceeding.

Exhibit 4A, Tab 2, Schedule 9, Section 5 provides further details about the processes utilized in the Program Management and Execution stage of the AM Process.

D1.2.4 Performance Measurement

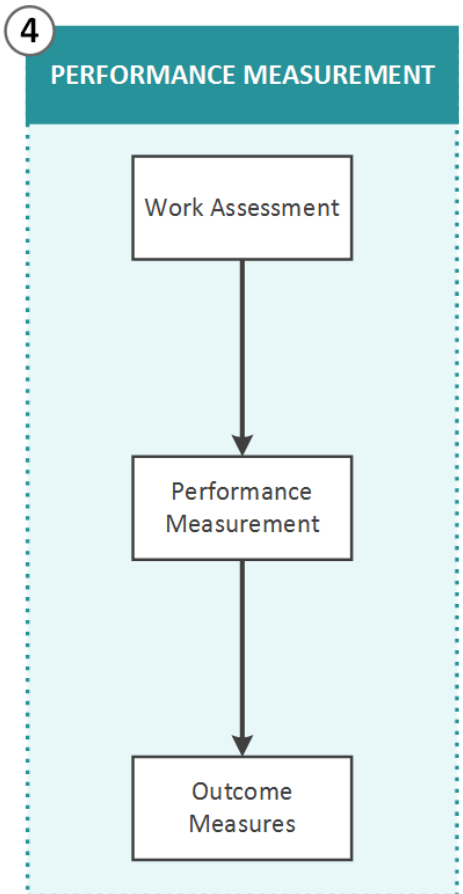


Figure 7: Performance Measurement Stage

The final stage of the AM Process is to monitor the performance of the investment program, to determine to what extent projects have contributed to expected outcomes. These results feedback into the annual IPPR process so that Toronto Hydro can modify programs and refine objectives if necessary.

Some key examples of outcome measures that Toronto Hydro tracks in relation to the capital and maintenance expenditure plans include:

- System Health;
- System Capacity;
- SAIDI and SAIFI for Defective Equipment; and
- FESI-7.

Further details on Toronto Hydro's performance measures for the 2020-2024 DSP are provided in Section C.

D1.2.5 Standards and Practice Review

The Standards and Practice Review is driven by the need to evaluate particular standards and products to improve work execution. This process influences all four stages of the AM Process as planners, designers, and crews rely on this process to identify what equipment is available to them and its appropriate use. The review encompasses the necessary specifications and processes related to: (i) introducing standards and assets into the system; (ii) installation requirements; (iii) replacement considerations; (iv) identifying new assets to better meet system needs and customer preferences; (v) carrying out work in a consistent manner; and (vi) supporting improved safety on the system.

1) **New and revised standards:** Toronto Hydro routinely introduces new standards and revises existing standards to ensure safe and effective work execution on the system. New standards are created in response to a number of drivers, including but not limited to: (i) weather impacts; (ii) process or productivity improvements; (iii) quality; and (iv) safety. When Toronto Hydro revises a standard, other documents, such as the standard design practices followed by project designers, are updated to align with changes made.
2) **New products:** Introducing new products enables more efficient, safe, and reliable service to customers. Product requests are reviewed to ensure alignment with business needs, that the appropriate stakeholders are engaged, and that the product satisfies Electrical Safety Authority ("ESA") requirements for major and minor equipment approval. The need for a new product can be initiated for a number of reasons, including: (i) safety; (ii) productivity; (iii) increased flexibility; (iv) ability to meet system requirements; and (v) better technology available. For example, Toronto Hydro has introduced new 600V network equipment to deliver reliable service to the increasingly taller buildings being developed in the City of Toronto.
3) **Refurbishment and replacement of equipment:** When major equipment, such as transformers, network protectors, and switches, is returned from the field, Toronto Hydro evaluates, inspects, and tests them to determine whether the asset can be reused (i.e. repaired or refurbished) or replaced (i.e. scrapped).
4) **Quality improvements:** When a product that is not near end-of-life is returned from the field because of failure, it is investigated to determine the root cause of the failure. Investigations are conducted in-house or equipment is sent back to the manufacturer. If a quality issue is discovered, the manufacturer is notified and requested to make modifications to address the

issue. If it cannot be fixed by the manufacturer, a quality alert will be issued notifying users of the issue and the product's use may be discontinued.

5) **Standard design practice:** The standards review process provides planning and design stakeholders with the framework for standard design practices. These practices instill safety by design, enforce construction standards, and ensure alignment with business strategies and consistency between projects. The design practice set outs general guidelines with respect to technical matters, and refers to construction standards for specific details.
6) **Industry standards**: Toronto Hydro seeks to align with industry standards and best practices wherever possible. This avoids unnecessary custom made products which can drive up costs and maintenance complexity. Toronto Hydro is also part of an Inter-Utility Standards Forum ("IUSF"), through which utilities collaborate on solutions to common problems and develop common equipment specification.

D1.3 Asset Management Process Enhancements

Toronto Hydro's AM process has evolved since its conception. The utility is continuously enhancing its approach to asset management to ensure the process and strategies remain aligned with the needs of its customers and the distribution system.

The recent progression of Toronto Hydro's AM process is described in the following two sections:

- Evolution of the AM process (2005-2014); and
- Enhancements during the current filing period (2015-2019).

D1.3.1 Evolution of the AM Process (2005-2014)

Toronto Hydro's AM Process, including the data and tools used as part of the process, has evolved and matured significantly since the mid-2000s. At that time, Toronto Hydro primarily looked to the Institute of Asset Management's Publicly Available Specification ("PAS 55"), which had been published by the British Standards Institution in 2004. That specification and its revision in 2008 (i.e. PAS 55:2008) provided guidance with respect to good asset management principles, including those pertaining to information management, risk management, life cycle management, performance and condition monitoring, and failure investigations. Based on that guidance, and as a result of its commitment to be a leader in effective asset management, Toronto Hydro pursued and achieved the following major milestones over a 10-year period as depicted in Figure 8.

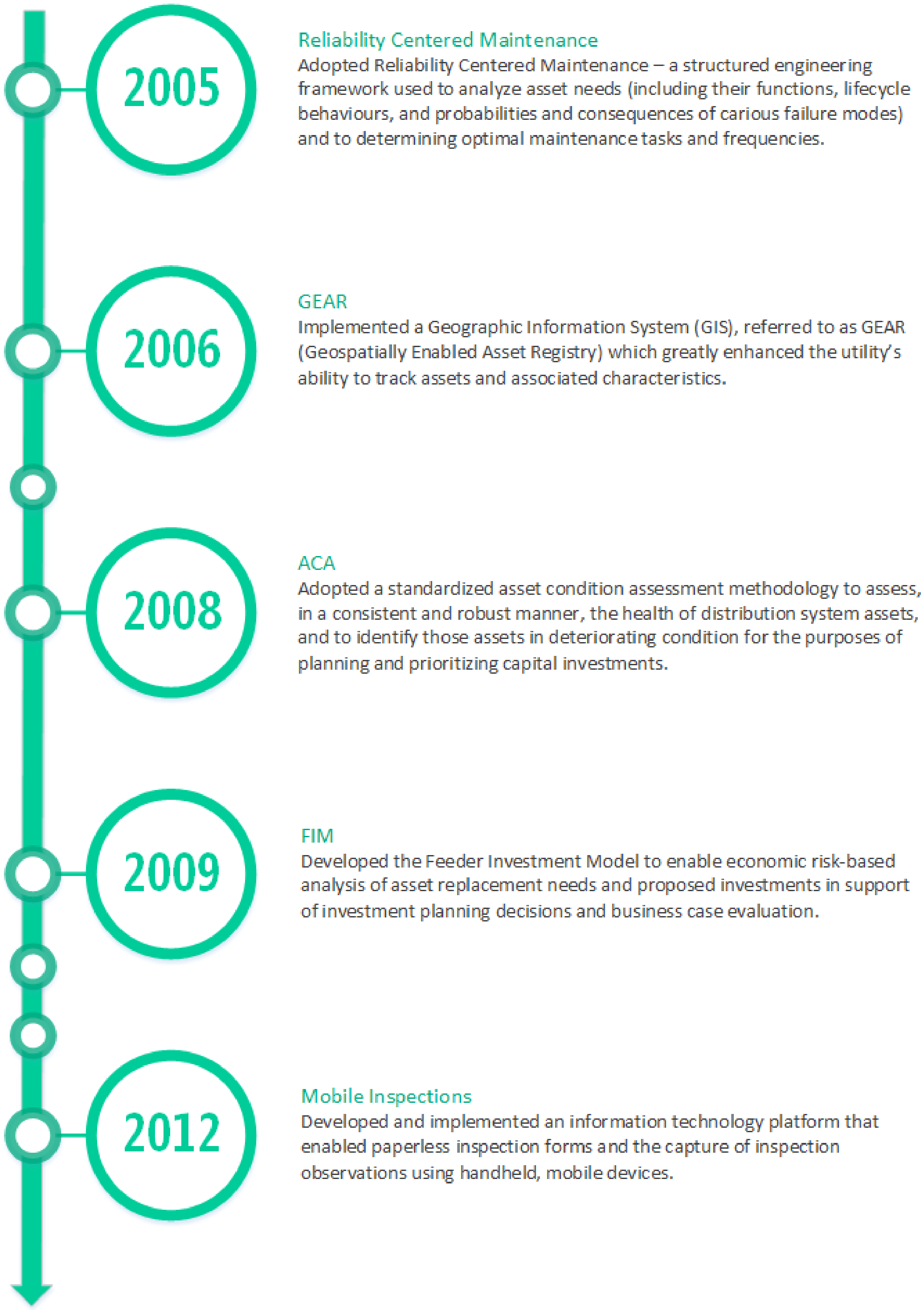


Figure 8: Evolution of the AM Process (2005-2014)

D1.3.2 Recent Enhancements (2015-2019)

Improvements to Toronto Hydro's AM Process over the 2015-2019 period are highlighted in Figure 9 below. The following section provides additional details on key process improvements.

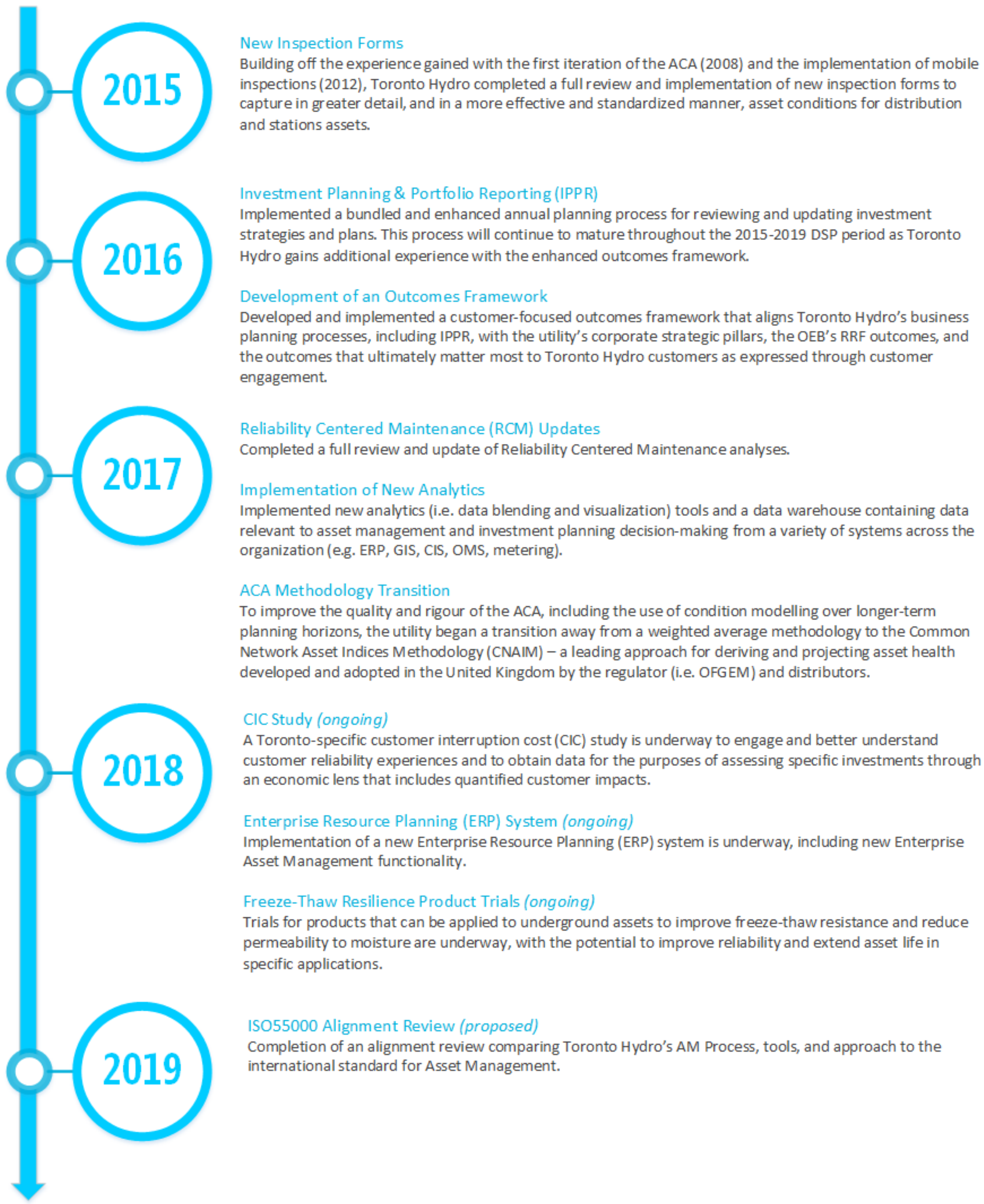


Figure 9: Recent Enhancements of the AM Process (2015-2019)

D1.3.2.1 Outcomes Framework

Toronto Hydro leveraged Customer Engagement results to develop an enhanced Outcomes Framework for the 2020-2024 planning horizon. Toronto Hydro used this Outcomes Framework to set the initial direction and result for the 2018-2024 Business Plan. The resulting 2020-2024 Capital Expenditure Plan includes measureable objectives that directly or indirectly relate the proposed level of spending in each program to the utility's strategic objective of continuous improvement in each of its six outcomes categories (and by extension, each of the four RRF outcomes): Reliability, Customer Service, Public Policy, Safety, Environment, and Financial.

Through these outcomes objectives, Toronto Hydro's capital programs aim to address the needs and challenges of the system in alignment with strategic focus areas and customer preferences. The utility developed its capital programs to maintain and improve reliability and safety, meet service and compliance obligations, address load capacity and growth needs, improve contingency constraints, and/or make necessary day-to-day operational investments. As a result, Toronto Hydro's DSP reflects a balance between customer preferences, affordability, and prioritized outcomes (as described in Section E2), with the overriding objective of delivering value for money.

D1.3.2.2 Asset Condition Assessment Update

Toronto Hydro has transitioned from the ACA methodology originally adopted in 2008 to an ACA model that provides more accurate and comprehensive condition-based analytics, and that better supports expenditure planning over longer time horizons. Toronto Hydro has long considered condition a key part of investment planning. With the emerging need to generate condition-based investment plans over horizons of five years or longer, and having encountered certain limitations in the existing weighted average condition assessment methodology, the utility decided to seek a more sophisticated condition methodology with projection modeling capabilities.

The model that Toronto Hydro has implemented is the Common Network Asset Indices Methodology ("CNAIM"). This methodology was developed and adopted by the major utilities in the United Kingdom – where utilities are expected to file eight-year business plans – in collaboration with the regulator (i.e. Ofgem). In terms of the functional outputs of the model, it is first and foremost a like-for-like upgrade on Toronto Hydro's existing model in the sense that it provides a more refined and reliable calculation of the condition score for an individual asset based on the most recently available inspection information for that asset. The new methodology also includes the ability to calculate future health scores for assets, providing further information on asset demographics that can be used to evaluate proposed investment strategies over the longer-term.

This model provides incremental benefits at the strategic level by facilitating projections of asset condition demographics by asset class. This allows Toronto Hydro to assess the current and future condition profiles of an asset class to better calibrate the level of investment necessary to either maintain or improve the amount of failure risk associated with its aging asset base over time.

Appendix C to this section of the DSP provides a detailed discussion of the new model, how Toronto Hydro implemented it, and the condition results by major asset class.

D1.3.2.3 Data Consolidation: Data Warehousing for Engineering Analytics

Toronto Hydro is currently developing an engineering data warehouse to streamline data access and perform "big data" calculations that can support planning and system investment strategies. In parallel, the utility has been deploying new data blending and analytics software, and has integrated software into business processes to improve productivity and drive new insights.

D1.3.2.4 Enterprise Resource Planning ("ERP") System Implementation

The existing enterprise systems are to be consolidated into one system so that data integrity can be improved. This will provide teams across Toronto Hydro access to one system with accurate and up-to-date information. See Exhibit 2B, Section 8.4 for further details on the implementation of a new ERP system.

D2 Overview of Distribution Assets

D2.1 Distribution Service Area and Trends

Toronto Hydro is one of the largest municipal electrical distribution utilities in North America, serving the City of Toronto – Canada's largest city. The city is bounded by Lake Ontario to the South, Steeles Avenue to the North, Mississauga (mainly Highway 427) to the West, and Scarborough/Pickering Townline to the East. As shown in Figure 1 below, Toronto Hydro's service territory can be divided into two geographic areas: (i) an urban centre in downtown Toronto with a high customer density and a large financial and entertainment district; and (ii) a suburban area around downtown Toronto with a lower customer density, which is colloquially referred to as the "Horseshoe" area.

Figure 1: Areas of the Toronto Hydro Distribution System

The following subsections discuss the characteristics of Toronto Hydro's service territory, including its customers and load growth profiles, climate and weather, and economic profile. Section D2.2 provides a detailed description of the utility's asset demographics, system configurations, and asset condition, and Section D2.3 provides a summary of system utilization.

D2.1.1 Customer and Load Growth

Toronto Hydro's distribution system supplies approximately 768,000 customers with a peak load of 4,810 MVA as of 2017. Toronto Hydro has been experiencing steady population and customer growth for many years, as shown in Figure 2.

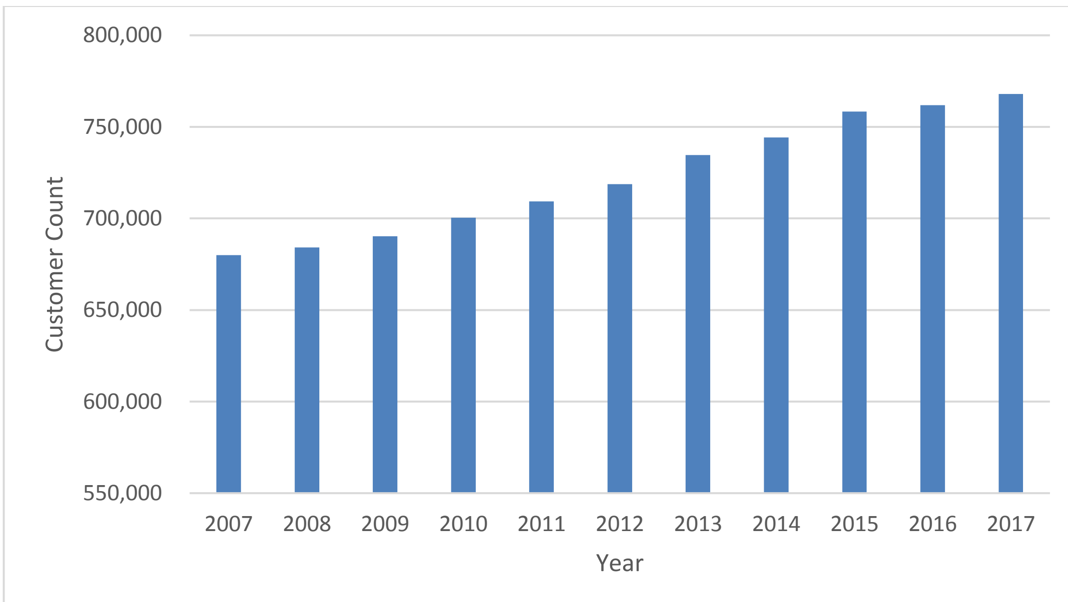


Figure 2: Historical Toronto Hydro Customer Counts

Despite steady customer and population growth, overall system peak load has remained relatively steady in recent years at approximately 5,000 MVA, as shown in Figure 3. It is important to note that system peak load varies with temperature.

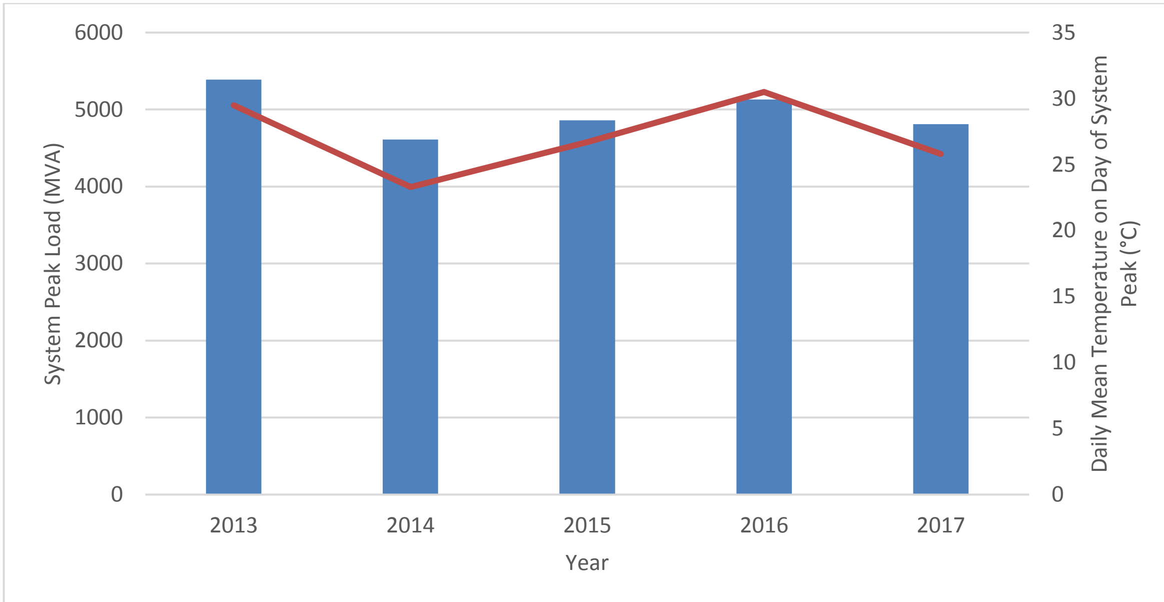


Figure 3: Historical Toronto Hydro System Peak Loading

However, Toronto continues to experience highly concentrated load growth in certain areas of the city primarily due to a high number of large condominium developments. Figures 4 and 5 show that Toronto has more buildings under construction than most North American cities, and a number of high-rise and mid-rise buildings under construction at a rate comparable to New York. This concentrated growth occurs mainly in the downtown area, but also along major transit corridors such as Yonge Street and Sheppard Avenue. The growth is pushing certain distribution and stations equipment to capacity. Infrastructure renewal and upgrades are required in these areas to support growth while maintaining satisfactory reliability and system resiliency.

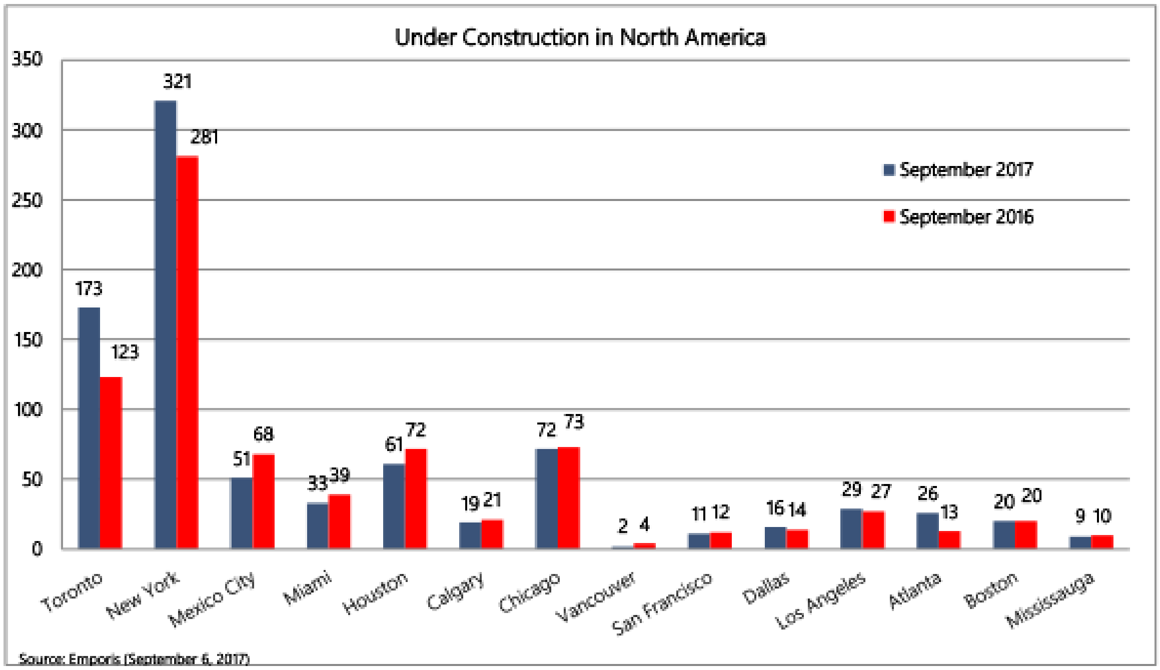


Figure 4: Number of High-Rise Buildings under Construction (Toronto Economic Update September 2017)

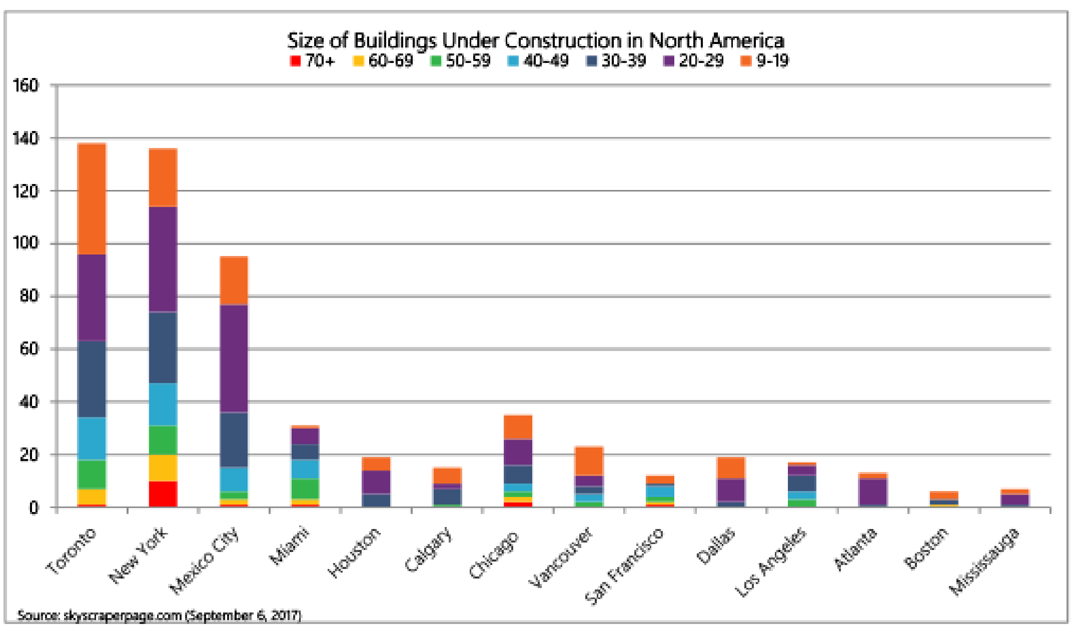


Figure 5: Number of Floors for High-Rise & Mid-Rise Buildings under Construction (Toronto Economic Update September 2017)

To keep pace with the growing city and ensure appropriate distribution system capacity, the utility plans to continue actively investing through the following programs, further described in Section E:

- Customer Connections (Section E5.1);
- Stations Expansion (Section E7.4);
- Load Demand (Section E5.3); and
- Generation Protection Monitoring & Control (Section E5.5).

D2.1.2 Climate and Weather

Climate change is a significant factor influencing Toronto Hydro's planning and operations. Scientists worldwide overwhelmingly agree that the planet is warming. By the year 2050, Toronto's climate is forecasted to be significantly different than the already changing climate seen today. For example, in Toronto, daily maximum temperatures of 25°C are expected to occur 106 times per year as opposed to 66 times per year currently. Daily maximum temperatures over 40°C, which have historically been an anomaly, are projected to occur up to seven times per year by 2050.[1] A warmer climate will also allow the atmosphere to hold more moisture, which is expected to lead to more frequent and severe extreme weather events such as ice storms and extreme rainfall events. These extreme events can cause major disruptions to Toronto Hydro's distribution system.

In addition to extreme weather events, Toronto experiences a wide range of weather conditions that may not be classified as extreme, but nevertheless have the potential to adversely affect the distribution system at various times during the year. Heat, high winds, heavy rainfall, freezing rain, and heavy snowfall have the potential to cause major system damage and extensive outages. Not only are these weather conditions projected to occur more frequently and with greater severity in the future due to climate change, trends from the past 20 years suggest that these changes are already affecting the system. Figure 6 below contains two charts depicting cumulative rainfall and the number of high wind days (i.e. with wind gusts exceeding 70 kilometres per hour) in Toronto over the past 20 years. With respect to rainfall, seven of the 10 highest rain fall years have occurred in the last 10 years. Similarly, six of the 10 years with the greatest number of days of wind gusts above 70 kilometres per hour have also occurred in the last 10 years (these years are highlighted in red).

[1] See Appendix D – Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment by AECOM (June 2015)

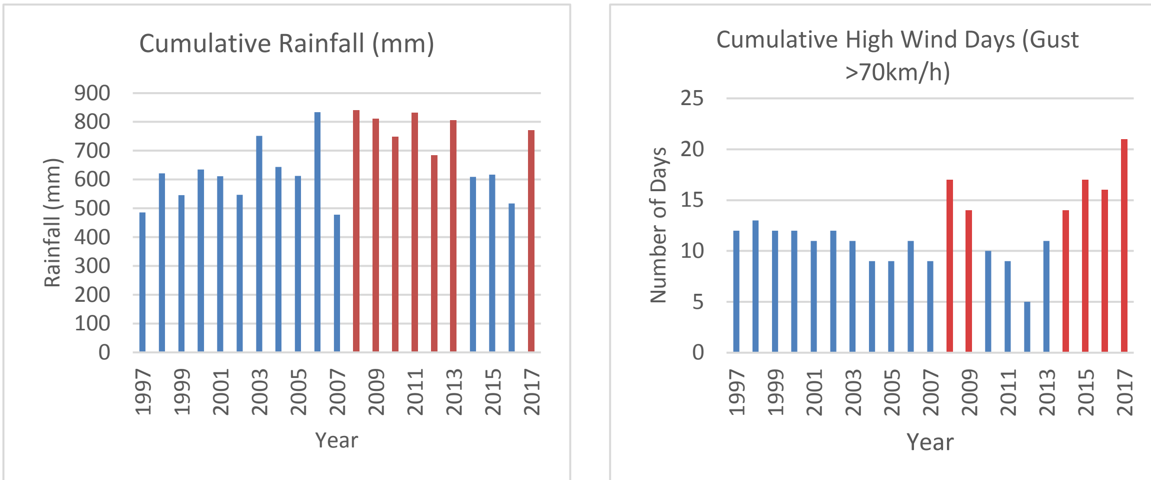


Figure 6: Cumulative Rainfall (left) and Number of High Wind Days (right) in Toronto[2]

These weather trends have increased reliability risks for Toronto Hydro's distribution system. Parts of the underground system are sensitive to significant rainfall, and in particular flooding, while the overhead system in general is sensitive to high winds, freezing rain and wet snow events resulting in damage and outages (e.g. from vegetation impact in proximity to overhead lines). In extreme cases, broken trees and the weight of ice and snow accretions bring lines, poles and associated equipment to the ground.

The aforementioned reliability risks are significant, as evidenced by examples of events that occurred in 2017. April and May of 2017 saw significant rainfall, causing a number of Toronto Hydro's vaults and cable chambers in the underground system to flood. From the perspective of the overhead system, high wind events in 2017 resulted in a 72 percent increase in the number of customer interruptions attributed to tree contacts compared to the average of the previous five years. Similarly, 2018 has seen significant storms and related damage, with four major events occurring during the first half of the year.

To better understand the risks related to increases in extreme and severe weather due to climate change, in June 2015, Toronto Hydro completed a vulnerability assessment following Engineers Canada's Public Infrastructure Engineering Vulnerability Committee ("PIEVC") protocol.[3] The

[2] Weather data compiled using Toronto Lester B. Pearson INTL A for January 1997 to June 2013 and Toronto INTL A for July 2013 to December 2017. Available from: Government of Canada, Weather, Climate and Hazard Historical Data online: <http://climate.weather.gc.ca/historical_data/search_historic_data_e.html>
[3] See Appendix D to Section D.

assessment identified areas of vulnerability to Toronto Hydro's infrastructure as a result of climate change. Following this study, a climate change adaptation road map was developed, along with initiatives relating to climate data validation, review of equipment specifications, and review of the load forecasting model.

Existing codes, standards, and regulations were developed with regard to historical weather data and do not always account for ongoing and future changes to the climate. In efforts to close this gap, Toronto Hydro now utilizes climate data projections for temperature, rainfall, and freezing rain in its equipment specifications and station load forecasting. Further, Toronto Hydro reviewed and updated major equipment specifications in 2016 to adapt to climate change, including:

- Revisions to submersible transformer specifications to require stainless steel construction and testing of the equipment's ability to withstand fully flooded conditions;
- Replacement of air-vented, padmounted switches with new standard SF_6 sealed-type, padmounted switches to remove risk of failure due to ingress of dirt and road contaminants on the live (i.e. energized) surface;
- Initiation of trials of solid dielectric transformers that do not contain oil and are designed to withstand extreme environmental conditions underground; and
- Adoption of breakaway links in tree-covered areas for residential customers with overhead service connections, intended to facilitate faster restoration after extreme weather and prevent damage to customer-owned service masts.

As part of the climate change adaptation roadmap, Toronto Hydro conducted analyses between 2016 and 2017 to better understand how assets and operational practices could be impacted by climate change:

1) An asset impact review that looked at how each type of asset is affected by the different aspects of climate change. Resulting recommendations for each type of asset were used to alter maintenance and asset management programs.
2) An industry review of climate adaptation best practices that included an evaluation of other major utilities as well as published papers. Vegetation management practices, system hardening practices, design criteria, and maintenance practices were areas identified as being affected by climate change.
3) An emergency restoration analysis to evaluate various strategies in the event of a failure in the underground electrical distribution infrastructure when load switching or re-routing is

not feasible. Restoration methods that utilities, specialized companies, and manufacturers have developed in this field were reviewed in order to restore the network as quickly and efficiently as possible. Evaluations and trials of the proposed methods will be investigated and tested prior to being implemented as a standard practice.

The following 2020-2024 program activities will contribute to Toronto Hydro's ongoing efforts to renew and enhance its system to increase resiliency to changes in the weather and climate, thereby supporting the continued delivery of outcomes expected by existing and future customers:

- As assets are replaced in the Overhead System Renewal program (Exhibit 2B, Section E6.5), Toronto Hydro will install taller poles with armless construction and tree-proof wire to reduce vegetation contact risks.
- Stainless steel submersible transformers will replace existing units as the utility carries out its Underground System Renewal – Horseshoe program (Exhibit 2B, Section E6.2).
- Underground System Renewal – Horseshoe program will also replace air-vented padmounted switches with SF_6 sealed-type padmounted switches to mitigate risk of failure due to ingress of dirt and road contaminants on the live surface.
- The Network System Renewal program (Exhibit 2B, Section E6.4) will replace non-submersible automatic transfer switches and remote power breakers with submersible equipment to tolerate flooding.
- The Network System Renewal program will also replace other end-of-life and deteriorated non-submersible protectors with submersible protectors to protect against flooding.
- The Network Condition Monitoring & Control program (Exhibit 2B, Section E7.3) will help the utility detect flooding in network vaults before it damages equipment.
- The Network Circuit Reconfiguration segment under the Network System Renewal program (Exhibit 2B, Section E6.4) will help the utility improve system restoration capabilities in the event of outages.
- Installation of flood mitigation systems at stations identified as being vulnerable to flooding will occur under the Stations Renewal program (Exhibit 2B, Section E6.6).
- New switchgear installed in the Stations Renewal or Station Expansion (Exhibit 2B, Section E6.6 and E7.4) programs will be specified to mitigate flood risk where appropriate (e.g. installing air-tight SF_6 switchgear or other engineered solutions).

- The Control Operations Reinforcement program (Exhibit 2B, Section E8.1) will improve Toronto Hydro's operational resiliency by developing a dual control centre at an existing work location.

Toronto Hydro is a partner of the City of Toronto in planning and preparing for the effects of climate change. The City's *ResilientTO* initiative includes a Resilient City Working Group that facilities collaboration between City divisions, agencies and corporations and external stakeholders on the topic of climate change resilience. Members share knowledge and technical information to facilitate the implementation of resilience actions within their operations.

D2.1.3 Economic Profile

The City of Toronto is Canada's economic and financial hub. It is home to the Toronto Stock Exchange, as well as the headquarters of five of the nation's largest banks. Toronto accounts for 10 percent of Canada's Gross Domestic Product ("GDP").[4] Its GDP growth has outperformed not only the national average, but also many of the most developed countries in the world in the past year, which is a trend that is expected to continue over the next year.[5]

Toronto also has a diverse industrial and commercial base comprised of 13 key sectors including aerospace, financial services, education, life sciences, technology, food, entertainment, and tourism.[6] The critical and growing importance of Toronto's economy underscores the necessity of continuing to invest sufficiently to ensure the delivery of value for current and future distribution customers and to prepare for technology driven change in this highly urbanized area.

D2.1.4 Toronto Hydro's Evolving Role in the City of Toronto

The role that Toronto Hydro plays in its service territory is evolving as new technologies emerge. In many cases, local and provincial policy imperatives aim to accelerate the uptake of new energy related technologies such as distributed generation and energy resources, and power quality, reliability and resiliency solutions.

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[4] City of Toronto, Business and Economic Development facts, (2013), online: <http://www.toronto.ca/toronto_facts/business_econdev.html>. ["Toronto Business and Economic Development Facts"]
[5] City of Toronto, Toronto Economic Bulletin, Conference Board (December 2016 & September 2017) and OECD Economic Outlook – Interim Release, September 2017
[6] City of Toronto, Business & Economy, online: <https://www.toronto.ca/business-economy/industry-sector-support/>. ["Industry Sector Support"].

One example is the City of Toronto's climate change action plan and long-term vision. A key pillar of this plan is *TransformTO*,[7] which identifies how the City plans to reduce greenhouse gas emissions, improve health, grow the economy, and improve social equity. One of the major commitments of this plan is for 100 percent of vehicles in Toronto to use low-carbon energy by 2050. As part of achieving this goal, the Toronto Transit Commission ("TTC") is planning to convert its fleet of busses from diesel hybrid to electric, which will require upgrades to the distribution feeders supplying the TTC's Arrow Road Garage.[8]

Provincial and federal policy targeting greenhouse gas reductions is also a driver of technological change. Provincial energy policy actively supports and incentivizes the connection of renewable energy projects to the local distribution system. As of the end of 2017, Toronto Hydro has connected 1,750 renewable energy projects to its system, totaling 97 MW of generation capacity. As discussed in Section E3, Toronto Hydro anticipates steady growth in generation connections going forward and is planning to invest in necessary renewable enabling improvements, including monitoring and control technologies, and energy storage systems to facilitate this growth during the 2020-2024 period.

D2.2 System Demographics and Characteristics

Toronto Hydro's distribution system consists of a mix of overhead, underground, network, and stations infrastructure. This infrastructure operates at voltages of 27.6 kV, 13.8 kV, and 4.16 kV, and includes approximately 60,000 distribution transformers, 17,000 primary switches, 15,000 kilometres of overhead conductors, and 13,000 kilometres of underground cables as of 2017. Unless otherwise mentioned, asset demographic information provided herein is as of 2017.

The following sections provide details on these sub-systems and how each sub-system relates to Toronto Hydro's major asset management objectives. As discussed in Exhibit 2B, Section D3, Toronto Hydro manages its distribution infrastructure and plans capital investments and maintenance to achieve asset management objectives, specifically, the attainment of applicable outcomes. For further details on forecasted asset management measures for the 2020-2024 period, please see Exhibit 2B, Section C1.5.

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[7] City of Toronto, TransformTO, (2017), online: <https://www.toronto.ca/services-payments/water-environment/environmentally-friendly-city-initiatives/transformto>. ["TransformTO"].
[8] See Section E

The following table and accompanying explanations provide an introduction to Toronto Hydro's sub-systems through the lens of a core subset of asset management performance measures, all of which relate directly or indirectly to Toronto Hydro's outcomes.

1 **Table 1: Asset Management Performance Indicators by System Type**

System	Oil Deficiencies (Number of assets)	Priority Deficiencies (Number assigned)	Customer Hours of Interruption due to Defective Equipment	Customer Interruptions due to Defective Equipment	Condition[9] (Percentage of Assets in HI4 or HI5)	Oil Containing PCBs (Number of assets with oil containing or at risk of containing PCB)	Age (Percentage of Assets past Useful Life)	Legacy Assets
	Lagging Indicator of Performance				Leading Indicator of Performance			
Overhead	12 *(2%)*	845 *(10%)*	108,258 *(33%)*	149,116 *(39%)*	11%	6,412 *(60%)*	17%	3151 Box Construction Poles 54 km of Rear Lot 31,000 poles with porcelain insulators
Underground	407 *(75%)*	5,388 *(66%)*	207,508 *(62%)*	217,833 *(57%)*	3%	3,799 *(35%)*	25%	809 km of Direct-Buried Cable 66 Transclosures 1,186 km of PILC[10] Cable 226 km AILC[11] Cables
Network	111 *(20%)*	1,281 *(16%)*	131 *(0%)*	146 *(0%)*	5%	114 *(1%)*	24%	753 Non-Submersible Network Units 985 vaults without communication
Stations	16 *(3%)*	678 *(8%)*	16,881 *(5%)*	12,600 *(3%)*	8%	452 *(4%)*	37%	364 legacy breakers at TSs[12] 592 legacy breakers at MSs[13]
Total	**546 *(100%)***	**8,192 *(100%)***	**332,778 *(100%)***	**379,695 *(100%)***	**9%**	**10,777 *(100%)***	**24%**	-

2 **Notes**: All figures are 2017 year-end actuals, unless otherwise noted.

[9] See Exhibit 2B, Section D, Appendix C for the Asset Condition Assessment description and classification details
[10] Paper Insulated Lead Covered ("PILC") cable
[11] Asbestos Insulated Lead-Covered ("AILC") cable
[12] Transformer Station ("TS")
[13] Municipal Station ("MS")

- **Oil Deficiencies:** An oil deficiency is any observation related to oil (e.g. dried oil, oil leak) made during planned asset inspections. These are reported by inspectors when inspecting equipment and components that are known to or intended to contain oil. Oil deficiencies are an indicator of the likelihood of oil spills. The primary driver for this metric is to protect the environment from oil spills and to adhere to federal, provincial, and municipal legislation, regulations, and by-laws pertaining to the release of oil in the environment. Toronto Hydro strives to achieve zero oil leaks into the environment. Programs that contribute to the management of this measure are Preventative and Predictive Maintenance programs for oil filled equipment (discussed in Exhibit 4A, Tab 2, Schedules 1, 2, and 3), and capital programs that replace deteriorating oil filled equipment, including Underground System Renewal (Sections E6.2 and E6.3) and Reactive and Corrective Capital (Section E6.7). While Toronto Hydro strives to reduce the risk of all oil spills, the utility plans to report specifically on the number of PCB-contaminated oil spills as an outcome in 2020-2024 as this is a critical priority for the period.
- **Priority Deficiencies**: Toronto Hydro defines "priority deficiencies" as the subset of all equipment deficiencies that require intervention on a reactive or corrective basis. Each year, Toronto Hydro identifies between 15,000 and 25,000 total deficiencies through planned inspections, responding to equipment failures and power interruptions, or through the course of day-to-day work. Priority deficiencies are deficiencies that pose a high risk to reliability, safety, or the environment and are assigned as a priority 1 (P1), priority 2 (P2), or priority 3 (P3) for the purposes of addressing the deficiency. Each category corresponds to a level of risk (with P1 being the highest risk) and a timeline for repairing the deficiency or replacing the asset. Toronto Hydro has various programs (including Reactive and Corrective Capital, Corrective Maintenance, and Emergency Response) to address asset deficiencies, some of which have already resulted in asset failure.[14] Given the risks, timely and effective responses to priority deficiencies are non-discretionary and must be taken over short time horizons (i.e. less than six months). Identifying and responding to priority deficiencies in a timely manner is critical to meeting the utility's performance objectives for key outcomes such as SAIDI and SAIFI, and the utility's safety and environmental objectives.
- **Customer Hours of Interruption ("CHI") and Customer Interruptions ("CI") (i.e. Outages)**: CHI and CI are measures of outage duration and frequency, scaled by the number of

[14] Exhibit 2B, Section E6.7 and Exhibit 4A, Tab 2, Schedule 4-5.

customers affected by each outage. Toronto Hydro uses this type of historical reliability data to identify priority project areas across all of its reliability-related programs, and to develop and pace investment program spending in order to improve key outcomes that the utility reports include SAIDI, SAIFI, and Feeders Experiencing Sustained Interruptions ("FESI").

- **Assets with Material Deterioration or at End of Serviceable Life**: As described in detail in Appendix C to Section D1, Toronto Hydro's asset condition assessment ("ACA") methodology assigns health index scores to assets based on observable condition variables, and categorizes these scores within five health index bands ("HI1" to "HI5"). Asset condition demographics are a strong predictor of future asset performance. Over the long-term, Toronto Hydro is focused on managing the number of assets in the HI3 ("moderate deterioration") to HI5 ("end of serviceable life") bands. Over the 2020-2024 period, in support of its objective of maintaining system performance, Toronto Hydro is proposing to monitor a new system health measure. Please see Section C for more details.
- **PCBs**: Toronto Hydro defines "PCB at-risk equipment" as an asset that: (i) is known to contain oil with greater than 2 ppm concentration of polychlorinated biphenyl ("PCB"); or (ii) has an unknown concentration of PCB and was manufactured in 1985 or earlier (and is therefore at a high risk of containing greater than 2 ppm PCB). This measure excludes cables. Due the toxic and persistent nature of PCBs, Environment Canada's *PCB Regulations*[15] prohibit the use of equipment that contains greater than 50 ppm PCBs, or the release of greater than one gram of PCBs, which could result from an oil leak with significantly less than 50 ppm. The City of Toronto also enforces its own PCB-related bylaws with a near-zero tolerance for the discharge of PCBs into the storm and sanitary sewer systems.[16]
- **Age**: Toronto Hydro monitors the percentage of its asset base that has passed its useful life or will pass that milestone by the end of the next planning horizon. As a key indicator of failure risk across the system, this information is used for long-term planning purposes. As of the end of 2017, approximately 24 percent of assets will be in-service past their useful life, as shown in Figure 7. By managing this measure over the long-term, the utility aims to provide predictability in the performance of key outcomes like reliability and safety for current and future customers.

[15] The *Canadian Environmental Protection Act*, PCB Regulations, SOR/2008-273
[16] Toronto Municipal Code, Chapter 681 – Sewers

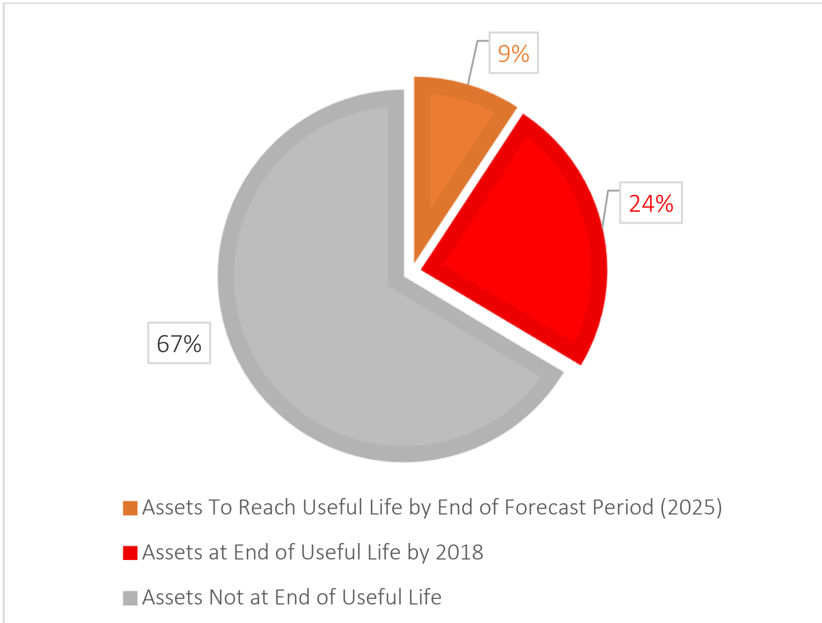


Figure 7: Assets Past Useful Life

- **Legacy Assets**: Legacy assets are specific asset types, configurations, or sub-systems that do not meet current Toronto Hydro standards, often feature obsolete components with limited or no supplier or skilled labour support to maintain, repair or replace these assets and result in elevated reliability, safety, or environmental risks. One of Toronto Hydro's asset management strategies is to eliminate all high risk legacy assets within a specific and reasonable timeframe. The specific legacy assets are discussed further in the following sections as part of the overhead, underground, network, and stations systems descriptions. Table 2 above provides an estimate of the remaining volumes of certain key legacy assets across Toronto Hydro's different subsystems. For further details on specific legacy asset replacement and pacing, please see Exhibit 2B, Section E2. Toronto Hydro plans to report reductions in legacy asset risk for specific types of legacy assets as safety and reliability outcomes during the 2020-2024 period. See Section C for more information.

The following sections provide a more detailed view of the overhead, underground, network, and stations sub-systems of Toronto Hydro's distribution system, including the age and condition demographics of the assets, and associated system challenges. Each section provides a further breakdown of how those sub-systems relate to Toronto Hydro's asset management indicators and measures discussed above and in Section C.

D2.2.1 Overhead Grid System

The overhead system consists of poles, overhead conductors, overhead transformers, overhead switches, and other equipment including lightning arrestors, guying hardware, and wires. All of these assets are placed above ground in areas with sufficient space and clearance from overhead obstructions (e.g. trees and buildings). Advantages of using an overhead system are that it is cost effective and allows for more expeditious fault identification and outage restoration, given that all assets are out in the open and visible to crews. Disadvantages of this system are that it is prone to foreign interference from vehicles, trees, animals, and weather-related outages (i.e. caused by high winds or freezing rain), and requires adequate clearances to operate and maintain.

Figure 8: Overhead Distribution Transformer

The majority of Toronto Hydro's overhead system is operated at 27.6 kV and 13.8 kV, but a subset of the overhead system operates at 4.16 kV. This system consists of approximately 135,000 poles, 7,619 overhead switches, 29,628 overhead transformers, 9,103 conductor-kilometres of overhead primary, and 11,450 circuit-kilometres of overhead secondary conductors as of 2017. The overhead system makes up approximately 57 percent of the total distribution system within the City of Toronto.

Asset management activities related to the overhead distribution system focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies, managing system performance with respect to reliability and power quality, and asset stewardship over the assets' lifespan.

Figure 9 provides the age demographic distribution of major overhead assets. As of 2017, over a quarter of poles are beyond their useful life of 45 years, and a significant percentage of pole top transformers are at or approaching their useful life of 35 years. Without proactive intervention, Toronto Hydro projects that the percentage of pole top transformers having reached or exceeded useful life will significantly increase from 14 percent as of 2017 to approximately 40 percent by 2024.

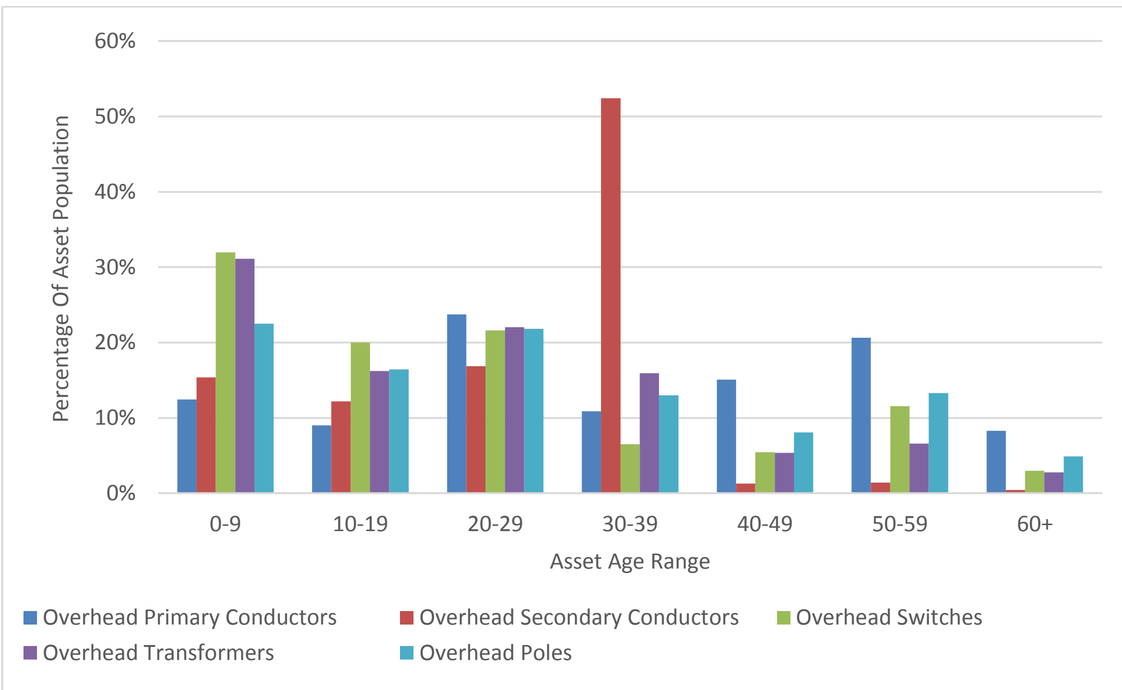


Figure 9: Overhead Assets Age Demographics as of 2017

Wood poles and overhead switches are the two major overhead asset classes for which Toronto Hydro performs an Asset Condition Assessment ("ACA"), as summarized in Figure 10. With respect to wood poles, the ACA showed that approximately 31 percent of Toronto Hydro's wood poles have at least moderate deterioration as of 2017. With over 20,000 wood poles in HI3 condition (i.e. "moderate deterioration"), over 11,000 in HI4 condition (i.e. "material deterioration"), and approximately 1,100 in HI5 condition (i.e. "end of serviceable life"), pole replacement will continue to be a significant driver of both reactive and planned investment through 2024. The need for a continued pole replacement strategy and investment is underscored by the projected rate of deterioration across this asset class over the rate period, as discussed in Exhibit 2B, Section E6.5.

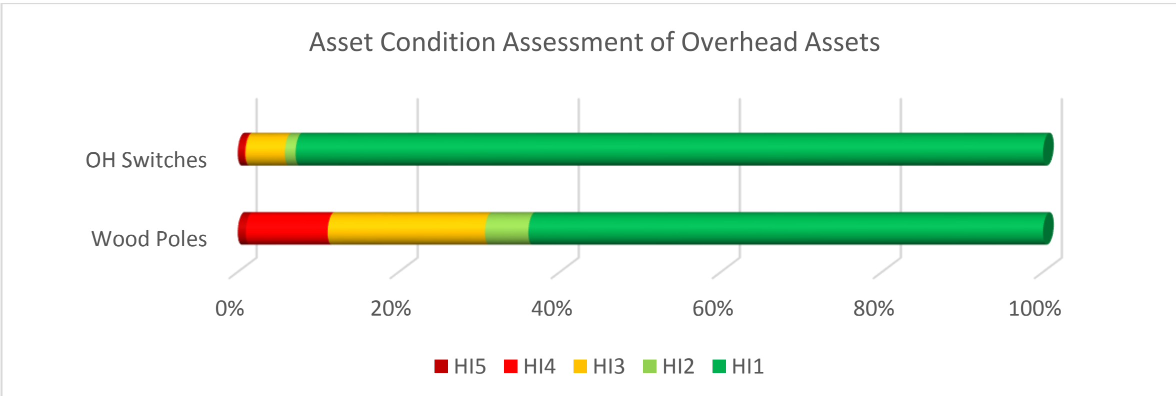


Figure 10: Asset Condition Assessment of Overhead Assets as of 2017

Other key asset management performance measures that are relevant to the overhead system include:

- **Oil Deficiencies**: Pole top transformers are the only asset type in the overhead system that may exhibit oil deficiencies. During the 2015-2017 period, Toronto Hydro found on average 27 pole-top transformers with oil deficiencies annually. The Overhead System Renewal program and Reactive and Corrective Capital program (Section E6.7) will continue to target pole top transformers exhibiting oil deficiencies.
- **Priority Deficiencies:** Overhead assets are susceptible to external interference from animals, insects, adverse weather, and vegetation contacts. These factors accelerate degradation processes and cause damage. From 2013 to 2017, Toronto Hydro issued more than 5,500 work requests to address deficiencies, predominantly for failing or failed overhead assets. In 2017 alone, Toronto Hydro classified 422 P1, 316 P2, and 107 P3 priority deficiencies on the overhead system.
- **PCBs**: Pole top transformers are the only asset type in the overhead system that are known to contain PCB contaminated oil. As of the end of 2017, about 6,400 PCB pole top transformers containing or at risk of containing PCBs remained on the system. By replacing these assets, which will be operating beyond useful life, by 2025, predominantly through the Overhead System Renewal program (Section E6.5), Toronto Hydro endeavours to eliminate the risk of PCB-contaminated oil spills.

D2.2.1.1 Overhead Legacy Equipment

On the overhead system, a major challenge facing Toronto Hydro stems from legacy overhead assets such as porcelain insulators and arrestors, non-standard animal guards, and legacy construction types such as rear lot and box construction. These challenges contribute to poor reliability performance, safety risks, and other undesirable outcomes. Capital investment programs that are planned to target and mitigate challenges within the overhead system include: Area Conversions (Section E6.1), Overhead System Renewal (Section E6.5), and Reactive and Corrective Capital (Section E6.7).

1. Obsolete and deteriorating overhead accessories

Overhead accessories include three major categories: insulator hardware, conductors, and animal guards. These assets are interconnected and integrated with transformers, poles, and switches and are vital components of the distribution system.

- **Legacy Insulator Hardware:** Toronto Hydro's legacy insulators are predominately porcelain, which is an insulation material that has been commonly used for switches, lightning arrestors, terminators, and line posts. The failure modes for assets with porcelain insulating material typically involve assets cracking and breaking apart. In some cases, discharge of fragments due to weakening structural integrity of the material could occur as a result of a failure. In general, porcelain material tends to have a high risk of failure due to its tendency for contamination build-up that leads to electrical tracking (i.e. the breakdown of insulation materials, which can lead to faults), and as such, will be replaced with polymeric material.

  Porcelain hardware has the potential to fail in a catastrophic manner, releasing porcelain shards which can damage nearby equipment and public property. For example, one porcelain insulator failure incident in Toronto sent shards of porcelain into the balcony of a nearby home, shattering the window of the family room and causing damage to the windshield of a nearby police car. The effects of this porcelain pothead failure can be seen in Figure 11.

Figure 11: Porcelain Pothead Failure

- **Animal Guards:** Existing legacy wildlife protection on Toronto Hydro's overhead distribution system consists of "Guthrie" guard animal protectors. Toronto Hydro is installing improved animal guards that use a cone shaped guard on the bushing with an accompanying insulated drop wire. This design provides an improved physical non-conductive barrier. Figure 12 below shows the difference between "Guthrie" and the new animal guards used by Toronto Hydro to guard against wildlife.

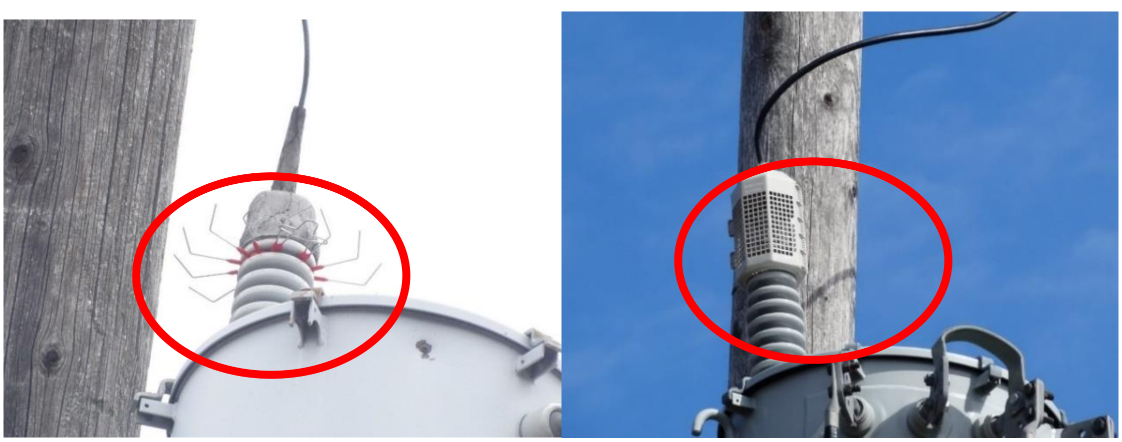


Figure 12: Animal Guards – Guthrie Guard (left), Newer Wildlife Guard (Right)

2. Legacy construction types

- **Rear Lot Construction:** This consists of overhead and underground assets that are installed in the backyard, or rear lot, and are generally operating near or beyond useful life. These assets were installed to serve residential customers in the Horseshoe region of Toronto. Due to accessibility limitations, outages on the rear lot plant tend to be longer in duration. The location of the plant also presents safety risks to customers and employees. Toronto Hydro is continuing to replace rear lot plant with standard, front lot underground circuits as part of the Area Conversions program (Section E6.1).

- **Box Construction:** These overhead feeders are located along main streets in the downtown area and serve residential neighborhoods and small commercial customers. The congested, box-like framing of the circuits prevents crews from establishing safe limits of approach to live conductors, which in turn restricts operations and leads to longer power restoration times for customers when compared to modern overhead standards. Toronto Hydro is continuing to replace box construction plant with standard overhead circuits as part of the Area Conversions program (Section E6.1).

D2.2.1.2 Overhead Assets Failure Characteristics

Table 2 below highlights the failure modes and impacts of overhead asset failures.

Table 2: Overhead Asset Failure Modes

Asset	Failure Mode	Effects
Pole Top Transformer	a) Arc flash due to contamination of bushing. b) Corrosion of tank c) Winding Failure	a) Causes tracking and can lead to catastrophic failure (e.g. oil fire, spill). b) Causes oil leakage and potential environmental issues c) Causes outage to customers
Wood Poles & Auxiliary Equipment	a) Rotted pole (below ground and at ground level) b) Contamination of insulators c) Pest infestation	a) Pole and equipment on it could fall causing an outage, safety issues and environmental issues associated with oil leakage b) Pole can catch fire due to tracking c) Compromises pole strength; equipment can fall and drop; safety and environmental risks.
Overhead Switches	a) Burnt disconnect contacts due to contamination b) Corroded or loose connections	a) The switch would be damaged and require replacements b) Lead to a connection failure and a forced outage

D2.2.2 Underground Grid System

The underground system consists of cables, transformers, switches, and civil infrastructure. All of these assets are placed at grade, below grade, or inside building vaults. The underground system eliminates many non-asset risks that are present in the overhead system such as foreign interference and weather-related interruptions. However, this system also presents unique non-asset risks, such as flooding or faster deterioration due to moisture build-up. Although this system generally provides better reliability than the overhead system, the causes of outages are more difficult to identify and restoration may take longer because the assets are underground and not visible to crews.

The Horseshoe underground distribution system is operated at 27.6 kV, 13.8 kV, with a subset of the system operating at 4.16 kV. The downtown underground distribution system is operated at 13.8 kV, and 4.16 kV. The main underground configurations are either radial or looped, with radial being the predominant configuration in the downtown system.

System types and configurations are sometimes mixed to provide better reliability or flexibility when repairs are required, as is the case with Underground Residential Distribution ("URD"). URD is a distribution configuration in parts of the downtown area with primary cables, switches and distribution transformers placed underground while secondary voltage connections remain overhead. The primary feeders consist of a main-loop, sub-loop and branch circuits. Customers are supplied directly from either the sub-loops or branch circuits, which allow sectionalisation (i.e. the ability to use switching to segment a feeder into sections) within the feeder to minimize interruptions when work is required, or to allow partial restoration of the feeder under fault conditions. Figure 13 shows a picture of a typical installation.

Figure 13: Typical Layout of Underground Residential Distribution

Toronto Hydro's underground system consists of approximately 8,500 underground switches, 29,000 underground transformers, 11,000 cable chambers, and 12,697 circuit-kilometres of underground primary and 20,517 circuit-kilometres of underground secondary cables.

Asset management activities related to the underground distribution system focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies, managing system performance with respect to reliability and power quality, and asset stewardship over the assets' lifespan.

Figure 14 provides the age demographic distribution of major underground assets. As of 2017, approximately 20 percent of underground transformers and over 20 percent of cable chambers are at or approaching their useful life of 35 years. Without proactive intervention, Toronto Hydro projects that the percentage of underground transformers and cable chambers having reached or exceeded useful life will increase from approximately 20 percent to 35 percent and 30 percent, respectively by 2024.

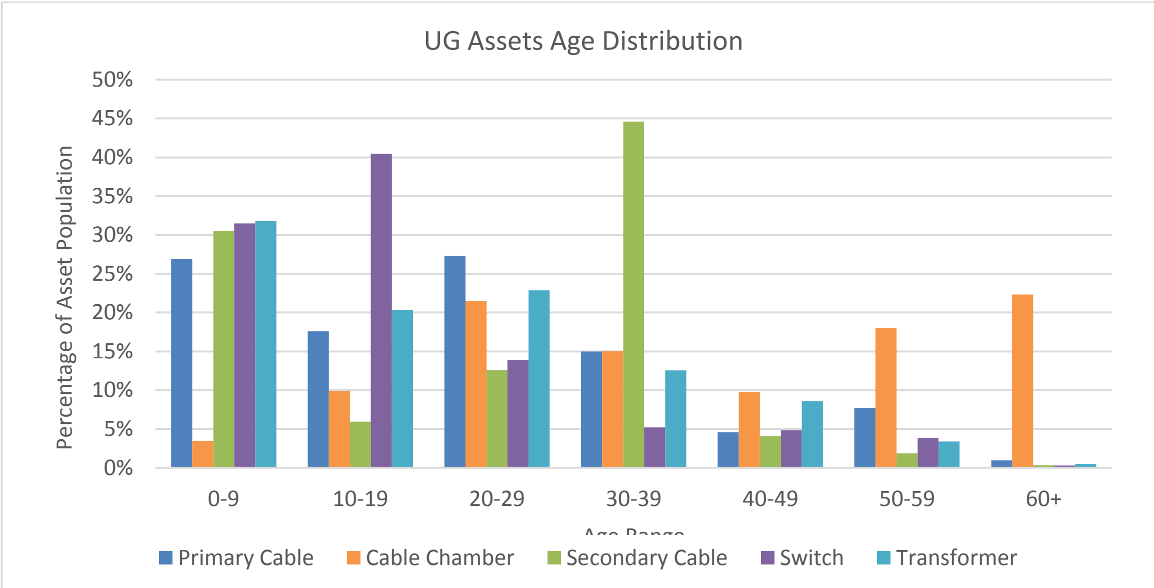


Figure 14: Underground Assets Age Demographic as of 2017

Underground switches and cable chambers are two major underground asset classes for which Toronto Hydro performs an ACA. As shown in Figure 15, approximately 14 percent of Toronto Hydro's underground switches and approximately 17 percent of cable chambers have at least moderate deterioration (i.e. HI3, HI4, and HI5) as of 2017. With over 1,300 cable chambers in HI3 condition, almost 400 in HI4 condition, and almost 100 in HI5 condition (i.e. "end of serviceable life"), cable chamber replacement will continue to be a significant driver of both reactive and planned investment through 2024 and beyond.

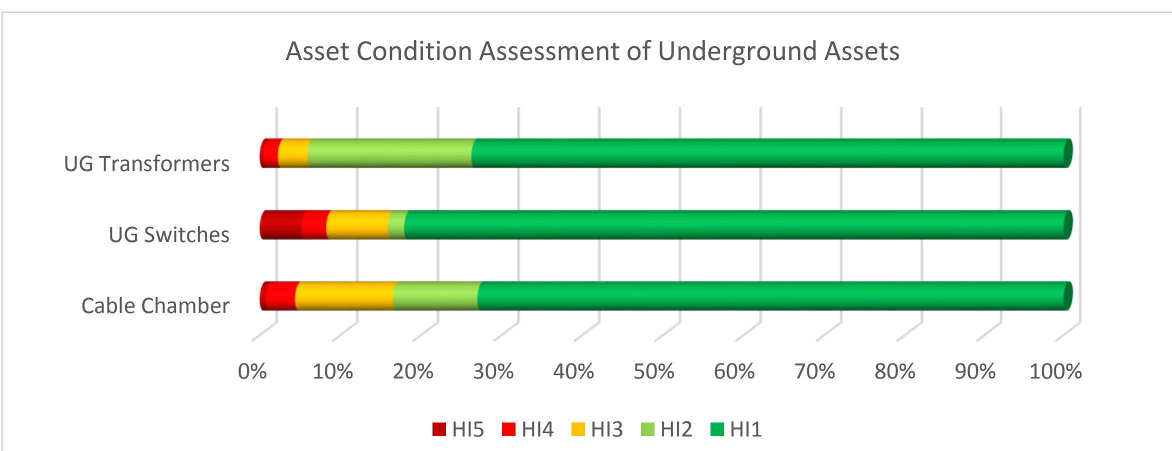


Figure 15: Asset Condition Assessment of Underground Assets as of 2017

Other key asset management performance measures that are relevant to the underground system include:

- **Oil Deficiencies:** During the 2015-2017 period, Toronto Hydro found, on average, 426 underground transformers with oil deficiencies per year. Assets replaced in the Underground System Renewal programs and Reactive Capital program will include assets exhibiting oil deficiencies found during inspections.
- **Priority Deficiencies:** The underground distribution system includes many below-grade vaults and cable chambers. The assets housed within them include cables, splices, joints, ducts, vents, hatchways, sump pumps, protectors, transformers, and switches. From 2013 to 2017, Toronto Hydro issued more than 24,000 work requests to address failing or failed underground assets. In 2017 alone, Toronto Hydro identified 1,445 P1, 1,440 P2, and 3,784 P3 priority deficiencies on the underground system.
- **PCBs:** Toronto Hydro has various types of underground transformers (e.g. submersible, padmounted, vault, and network), all of which can potentially contain PCB contaminated oil. As of the end of 2017, approximately 3,800 are known to contain, or at risk of containing, PCB contaminated oil greater than 2 ppm. Toronto Hydro endeavours to eliminate the risk of PCB-contaminated oil spills by testing or replacing all of these assets, which will be operating beyond useful life, by 2025, predominantly through the Underground System Renewal programs (Section E6.2 and E6.3). If sub-standard conditions are found during inspections, replacements may be done through the Reactive and Corrective Capital program.

D2.2.2.1 Underground Legacy Equipment

1. Direct-Buried XLPE Cable

Cables are the single greatest contributor to defective equipment caused outages on Toronto Hydro's system, contributing on average 140,000 CHIs annually. The underground system in the Horseshoe area consists of 809 circuit-kilometres that are of a legacy and obsolete installation type, namely direct-buried cross-linked polyethylene ("XLPE") cable (or duct). Over 70 percent of direct-buried cable has reached or passed its useful life as of 2017. Without investment, 90 percent will be at or beyond useful life by 2024. This would have a negative impact on reliability, which would erode and eventually reverse the recent improvements on the underground system. These cables are susceptible to outages due to direct exposure to environmental conditions. "Water treeing" is the most significant degradation process for XLPE cable, and starts with moisture penetration into the cable insulation in the presence of an AC electric field. These “trees” are microscopic tears within the dielectric. Over time, continuous seepage of moisture into the insulation combined with electrical stress allows ions from the conductor to migrate into the microscopic tears. These tears then become carbonized and form electrical trees. Once this final stage of water treeing is reached, the cable quickly fails due to internal short circuits that occur between the primary conductor and the neutral shield on the outside of the cable insulation. Figure 16 depicts the internal short circuit that occurs once electrical trees are formed in the dielectric insulation. Figure 17 illustrates field and laboratory samples of microscopic voids bubbles) and damage to the insulation.

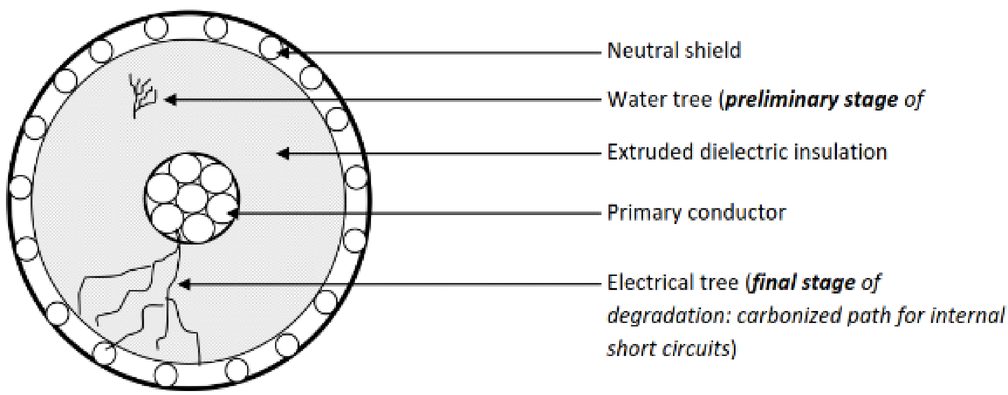


Figure 16: Cable Failure due to Electrical Treeing

Micro voids (bubbles) in the insulation

Visible damage due to moisture penetration

Formation of water and electrical tree (as seen under a microscope)

Figure 17: Field and Laboratory Sample of Microscopic Voids and Damage XLPE Insulation

There is an immediate need to address the issues associated with direct-buried XLPE type cables so as to maintain system reliability for current and future customers in the Horseshoe area of Toronto. For further information, please see the Underground System Renewal – Horseshoe Program described in Exhibit 2B, Section E6.2.

2. Underground Lead Cable (PILC and AILC)

The majority of the cable in Toronto Hydro's downtown underground system is of two types: Paper-Insulated Lead-Covered ("PILC") and Asbestos-Insulated Lead-Covered ("AILC"). These cables are typically found at busy intersections beneath the sidewalks and roads of Toronto's downtown core. PILC cables are used as 13.8 kV primary cables, while AILC cables are used as secondary cables rated at 600 V. AILC cable is typically found on the secondary network 120/208 V and 240/416 V systems. Approximately 55 percent or 1,100 circuit-kilometres of Toronto Hydro's downtown primary system consists of PILC cable, whereas 30 percent or 220 circuit-kilometres of all cable in the downtown network system consists of AILC cable.

Historically, utilities installed lead cable to take advantage of its reliability and compact design. However, over time, many utilities encountered environmental and health and safety issues with these cables. The industry has moved away from using these cables and for a number of years, there has been only one supplier remaining in the market for PILC (with none for AILC). Due to the supply risk (and the aforementioned environmental and safety risks), Toronto Hydro has avoided installing new lead cable for a number of years. Other utilities have taken a similar approach. As time passes, the number of individuals in the industry with the expert skillset required to work on lead cable in the field continues to diminish. To date, Toronto Hydro has largely dealt with lead cable failures and congestion issues reactively. Due to the advancing age of the population of lead cables and increasing issues with reliability issues, Toronto Hydro is introducing a new program to begin the long-term replacement of all lead cable with modern standard underground cable. This is discussed further in the Cable Renewal segment of the Underground System Renewal – Downtown program (Section E6.3).

D2.2.2.2 Underground Assets Failure Characteristics

Table 3 provides a brief overview of the failure modes and impacts of underground asset failures.

1 **Table 3: Underground Asset Failure Modes**

Asset	Failure Mode	Effects
Underground Cable	a) Insulation failure (water trees, overvoltage). b) Carbon tracking in PILC cable paper insulation due to absence of oil medium (oil leak). c) Degradation due to age (cracked or degraded jacket)	a) Electrical stresses may lead to the cable failing at that position. b) Impregnating oil dries up, cable overheats, degrading the insulation. c) Water ingress, corrosion of the metallic shield, penetration into the insulation (potentially causing water trees).
Submersible Transformers	a) Oil Leaking b) Corrosion of tank c) Gasket deterioration with age d) Corroded secondary terminations (compression or bolted lugs).	a) Transformer cooling and insulating properties are diminished, flash over may occur. b) Oil leaks, transformer cooling and insulating properties are diminished. Internal components damage and flash over will occur. c) This failure mode can arise due to a flooding or contamination. Hotspots are detected and the secondary termination fails.
Padmounted Transformers	a) Corroded enclosure. b) Enclosure has been exposed to moisture (ground water, moisture ingress). c) Contaminated or damaged insulating barriers; d) Degradation due to age/contamination. e) Gasket deterioration with age.	a) Public or animal access to the transformer. Transformer could be damaged or cause injury to the public. b) Improper ventilation, inadequate air flow, tracking, and flashover. Safety risks heighten as the transformer is located next to sidewalks. c) Tracking on the insulators, and eventual flashover. d) Insulation material breakdown and build-up of sludge; flashover will occur. e) Small traces of oil leaking. Ingress of moisture may occur, transformer cooling and insulating properties are diminished.

Asset	Failure Mode	Effects
Underground Switches (Padmounted)	a) Loss of insulating properties due to contamination, moisture ingress, or humidity. b) Switch has been exposed to moisture (ground water, moisture ingress.	a) Flashover. b) Improper ventilation and inadequate air flow creates tracking and possible flashover and failure, presenting a safety concern as the switch is located next to sidewalks.
Cable Chambers	a) Collapsed duct. b) Excessive water leakage through ducts. c) Structural degradation at the neck; d) Cable racks and arms rust and deterioration; e) Wall or roof failure, with corrosion in rebars.	a) Hotspot depending on the extent of damage, cable damage. Worst case can involve damage to connected equipment, posing a safety risk to the public. b) Degradation of walls, floor, corrosion to the racks. c) Access is restricted. If chamber is on roadway, a sinkhole may occur, posing a safety risk. d) Racks fall off the wall causing the cable or joint to be unsupported and possibly cause damage to other cables, posing a potential safety risk. e) Cracks, spalling, delamination of concrete and chunks of concrete falling down, structural collapse, or fire, posing a safety risk.

D2.2.3 Secondary Network System

The secondary network system, which is predominantly found in the downtown Toronto area, was initially installed in the early-to-mid 1900s to improve reliability for critical loads. As the system evolved, it became recognized for its ability to efficiently serve medium sized loads in areas that have high density and small and narrow sidewalks. Such areas do not have sufficient space above grade for distribution infrastructure. The network system consists of interconnected low-voltage secondary cables, which are installed in a grid or mesh configuration. These grids are supplied by multiple network units housed in network vaults fed by different feeders, and offer additional redundancies that the typical overhead and underground distribution systems do not. Should a single primary feeder experience an outage, network connected customers will continue to be supplied from alternate primary circuits, which continue to feed into the secondary grid or mesh. In this way, the secondary network system offers greater reliability than other underground or overhead systems.

At the heart of the network system are network units. The main difference between a network unit and a conventional radially-configured transformer is the addition of a network protector. The network protector prevents power from the secondary network grid from back feeding to the primary side. Should a fault occur on the primary side of the network unit, the network protector will automatically trip (i.e. open the switch to interrupt the current backfeeding into the fault). This protects the grid from the fault, and allows the remaining network units to keep the secondary network grid up and running.

Though the network system is better at handling normal failure scenarios, in the case of a catastrophic failure such as a vault fire, the entire secondary network grid that is connected to the vault must be dropped to allow emergency responders to extinguish the fire safely. In such a scenario, all connected customers are interrupted. To avoid these scenarios, network equipment must be kept in good condition to prevent vault fires or other failures from occurring. This is one of the reasons why Toronto Hydro takes a proactive approach to the maintenance and replacement of network units at risk of failure. Figure 18 below shows a typical submersible network unit.

Figure 18: Submersible Network Unit

The vaults that house network equipment are also an important component of the network system and must be maintained. If the integrity of a vault is compromised, the equipment inside the vault can be damaged, or the vault may become unsafe for employees. Unsafe conditions mean that crews are unable to complete any maintenance or repairs. As of 2017, Toronto Hydro has 575 vaults past their useful life. In addition, a number of vaults will need to be decommissioned as existing network areas redevelop into high rise areas, and some vaults that are otherwise in good structural condition, will require roof rebuilds.

Figure 19 provides the age demographic distribution of major network assets. As of 2017, approximately 16 percent of network units and approximately 1 percent of network vaults are at or approaching their useful life of 35 years and 60 years, respectively. Without intervention, Toronto Hydro projects that the percentage of network units having reached or exceeded useful life will increase from 16 percent to 25 percent, and the percentage of network vaults will balloon from 1 percent to 24 percent by 2024. Non-submersible network units are one asset type that Toronto Hydro plans to target specifically. These units are susceptible to water ingress and elevated failure risks even when in good condition. As such, they need to be replaced to reduce the failure risks on the network system. Replacements will occur on a prioritized basis considering factors such as condition, as discussed in Exhibit 2B, Section E6.4 (Network System Renewal).

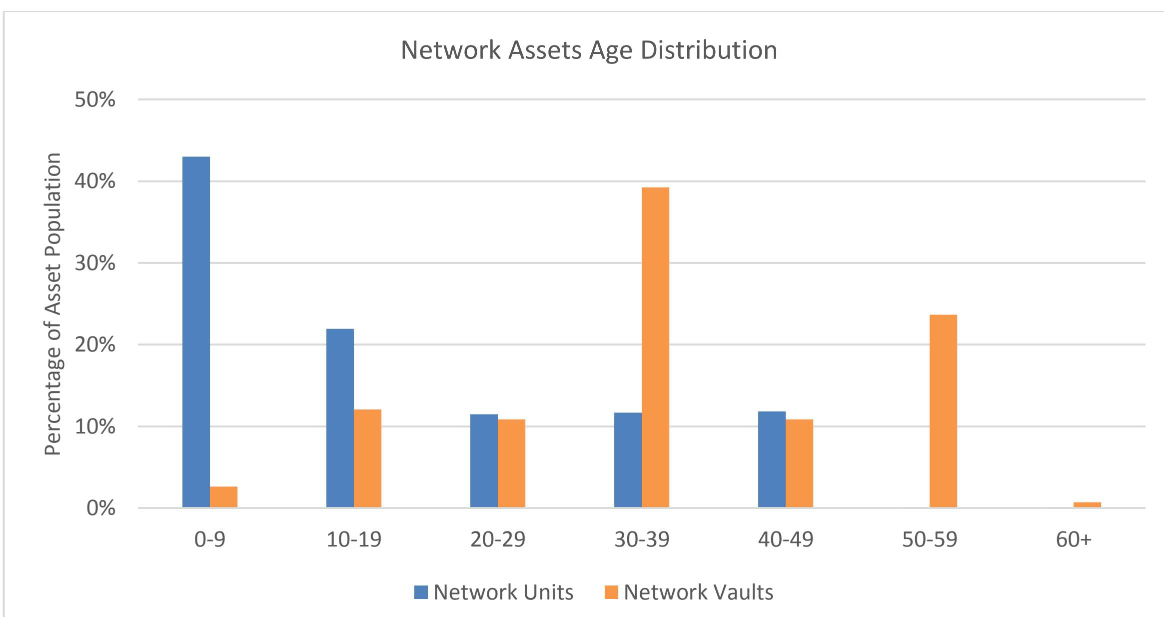


Figure 19: Network Assets Age Demographics as of 2017

Toronto Hydro performs an ACA for network transformers, network protectors, and network vault civil infrastructure. ACA results show that approximately 19 percent of Toronto Hydro's network vaults and 13 percent of network transformers have at least moderate deterioration as of 2017. With over 60 network vaults in HI3 condition, approximately 10 in HI4 condition, and approximately 30 in HI5 condition (i.e. "end of serviceable life"), Toronto Hydro expects network vault replacement will continue to be a significant driver of both reactive and planned investment through 2024.

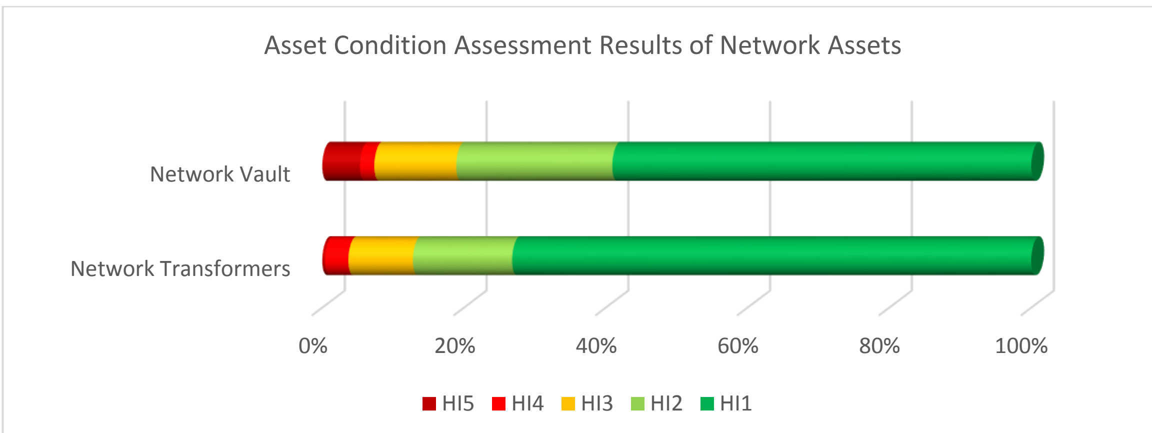


Figure 20: Asset Condition Assessment of Secondary Network Assets

Asset management activities related to the network focus on asset stewardship over asset life spans; mitigating environmental and safety risks, responding to system events and equipment deficiencies, and managing system performance with respect to reliability and power quality. The following summarizes what this means relative to the outcome measures for network assets, as set out in Table 2:

- **Oil Deficiencies**: Network transformers are the only asset group in the network system affected by this outcome. During the 2015-2017 period, Toronto Hydro found on average 114 oil deficiencies per year for network transformers. Assets replaced in the Network System Renewal Program and Reactive Capital Program will include assets exhibiting oil deficiencies found during inspections.
- **Priority Deficiencies**: Please see the discussion related to priority deficiencies under section D2.2.2 above as deficiencies related to the secondary network are generally tracked with all other underground deficiencies.
- **PCBs**: Network Transformers are the only asset group in the network system affected by this outcome. As of the end of 2017, Toronto Hydro has approximately 100 network transformers

that contain or are at risk of containing PCBs. Toronto Hydro endeavours to eliminate the risk of PCB-contaminated oil spills by 2025 by replacing end-of-life network units which include the aforementioned network transformers, which will be operating beyond useful life, through the Network Renewal Program (Exhibit 2B, Section E6.4).

D2.2.3.1 Network Legacy Equipment

On the network system, a major challenge facing Toronto Hydro stems from legacy network assets such as Automatic Transfer Switches ("ATS") and Reverse Power Breakers ("RPB"), and from non-submersible network protectors. These assets contribute to poor reliability performance, safety risks, and other undesirable outcomes. Capital investment programs that are planned to target and mitigate risks associated with these assets include: Network System Renewal (Section E6.4) and Reactive and Corrective Capital (Section E6.7).

1. **Replacing obsolete and deteriorating network equipment**

Legacy Network Equipment: The types of ATSs and RPBs used by Toronto Hydro are no longer produced or supported by the manufacturer, nor can they be properly maintained or replaced on a like-for-like basis. Failure can occur due to factors such as moisture penetration, or exposure to heavy debris and contamination, which results in equipment rusting and control electronics failure.

These assets can fail catastrophically, resulting in lengthy outages, vault fires, and damage to connected and adjacent equipment. The impact of an ATS failure can be seen in Figure 21 below. Toronto Hydro is continuing to replace ATS and RPB units with network transformer units and standalone network protectors, or 600A manual secondary switches.

Figure 21: Damage from a Vault Fire caused by Failure of an ATS Unit

Network Units with Non-submersible Protectors: Although network units are replaced based on condition, another consideration that informs investment decisions is the presence of "non-submersible" designs which are characterized by ventilated or semi-dust-tight protectors. The units are susceptible to water ingress and elevated failure risks even when in good condition. The failure modes for network units are flooding and internal transformer failure. Flooding can damage the protector mechanism, causing the unit to short, or fail to operate, whereas transformer failure can result from overloading, low oil, moisture ingress, or age-related insulation deterioration. Toronto Hydro is continuing to replace non-submersible protectors with submersible protectors that feature watertight cases to help address flooding risks as part of the Network System Renewal program (Section E6.4). Figure 22 below shows the difference between a ventilated network unit and a submersible network unit, where the black protector identified is of a submersible design to prevent water ingress.

Figure 22: A ventilated Network Unit (Left) and a Submersible Network Unit (Right)

D2.2.3.2 Network Assets Failure Characteristics

Low voltage secondary distribution networks are susceptible to similar failure modes as other underground distribution systems; however, the consequences of failure to operate and network customer service reliability are often different, as outlined in Table 4 below.

1 **Table 4: Network Asset Failure Modes**

Asset	Failure Mode	Effects
Underground Primary Cable	a) Internal arc occurs due to insulation degradation b) Internal arc occurs due to jacket damage c) Internal arc occurs due to mechanical stresses compromising geometry of cable	a) Station circuit breaker trips causing feeder outage b) Network vaults continue to operate under contingency, with possible equipment overloads. Network customers are not normally interrupted c) Dual radial customers supplied by faulted feeder are interrupted until switched to alternate feeder d) If multiple primary cable outages occur simultaneously, equipment overloads may force the Control Room to drop the entire network, resulting in widespread customer interruptions
Underground Secondary Cable	a) “Arcing” fault occurs due to insulation degradation b) “Solid” fault occurs when a failed cable conductor contacts another conductor	a) “Arcing” faults tend to self-clear without customer interruption. b) “Solid” faults may spread to adjacent cable junctions before self-clearing, resulting in interruptions to a small number of customers c) If self-cleared secondary cable faults are not identified, surrounding secondary cables may overload and eventually fault, resulting in interruptions to multiple customers
Network Transformer	a) Internal insulation failure caused by insulation degradation b) Corrosion of the steel tank or gasket failure results in insulating oil leakage	a) Internal network transformer faults tend to be cleared by the station feeder circuit breaker without breaching of the transformer tank. b) Oil leakage may cause contamination of the surrounding environment.

Asset	Failure Mode	Effects
Network Protector	a) Debris, salt, and moisture collect on the top of a network protector causing an electrical short b) Vault flooding allows water to enter the protector causing the mechanism to fail and possibly an electrical short.	a) Electrical shorts in protectors typically result in vault fires, with the possible destruction of all electrical equipment in the vault. The Fire Department normally requests interruption of electrical supplies to the vault b) Protector flooding normally only results in permanent damage to the mechanism, which must be replaced.

D2.2.4 Stations

Toronto Hydro's distribution system receives its transmission supply from Hydro One Networks Inc. ("Hydro One") at voltages of 230 kV, 115 kV, 27.6 kV, or 13.8 kV for use in the distribution system at Transformer Stations ("TS"). In general, Toronto Hydro owns all the medium voltage equipment up to the circuit breaker at a TS, subject to certain differences in ownership structures for each TS's equipment. Figure 23 below shows the ownership of station equipment and their associated demarcation point. In some areas, the voltage may be further stepped down to 13.8 kV or 4.16 kV at Municipal Stations ("MS") which are wholly-owned by Toronto Hydro.

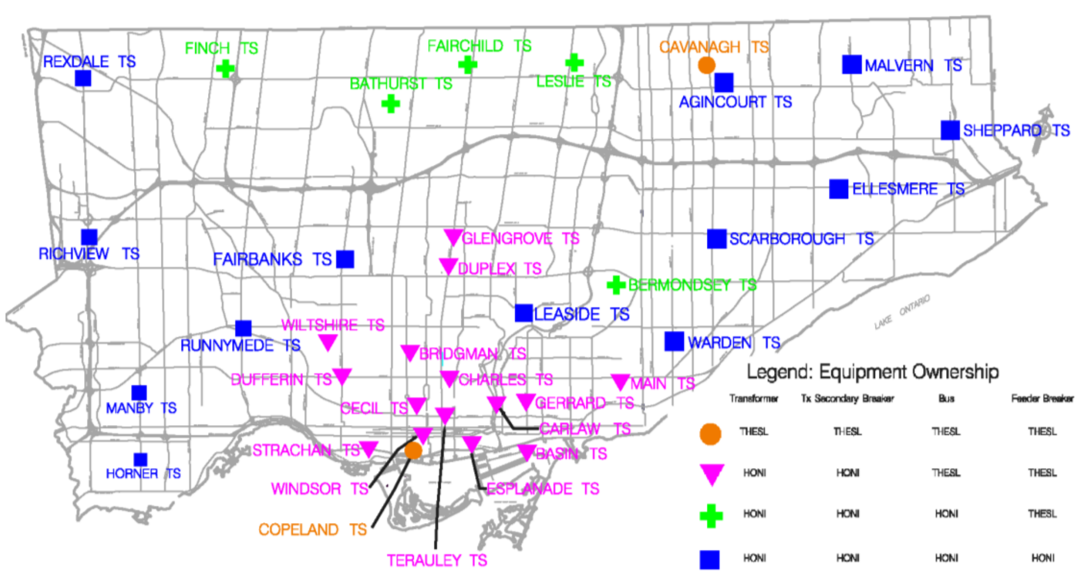


Figure 23: System Diagram of Station Components Ownership

Toronto Hydro is supplied by 36 TSs, including Copeland TS (as shown in Figure 23 above), and owns approximately 169 MSs.[17] Within these stations Toronto Hydro owns and operates approximately 209 switchgear, 215 power transformers, 90 outdoor circuit breakers, 201 remote terminal units ("RTUs"), and 187 direct-current ("DC") battery systems.

Feeders generally have at least one normally-open tie to another feeder to ensure there is a restoration option in case of an outage, or if planned work is required. [18] In the Horseshoe area, there are many normally open ties between feeders fed from the same bus or feeders fed from a different bus or station. This allows for increased operational flexibility and the ability to restore some load in the event of a bus or station outage. Feeders in the downtown area rely on a radial configuration with normally open ties to feeders supplied from the same bus, but never have ties with feeders fed from other stations. This configuration limits the restoration options for these feeders in case of a station outage. Toronto Hydro does look for opportunities to build contingency ties between different downtown stations where economical.

Asset management activities related to stations focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies when they are identified, managing system performance with respect to reliability and power quality, and asset stewardship over the assets' life span.

Figure 24 provides the age demographic distribution of major station assets. As of 2017, 40 percent of Toronto Hydro's switchgear, 51 percent of power transformers, 13 percent of outdoor breakers, and 35 percent of DC battery systems are operating at or beyond their useful life. Without proactive intervention, the proportion of station assets operating beyond their useful life will continue to increase. Station asset renewal is complex and entails considerable operational constraints which limit the achievable level of renewal in a given year. Consistent investment and renewal work is needed to sustainably mitigate and control the failure risk presented by these assets.

[17] 15 of which are in the process of being decommissioned.
[18] Secondary network systems and pilot-wire/line-differential based systems operate with multiple supply points in parallel and do not require a normally open tie.

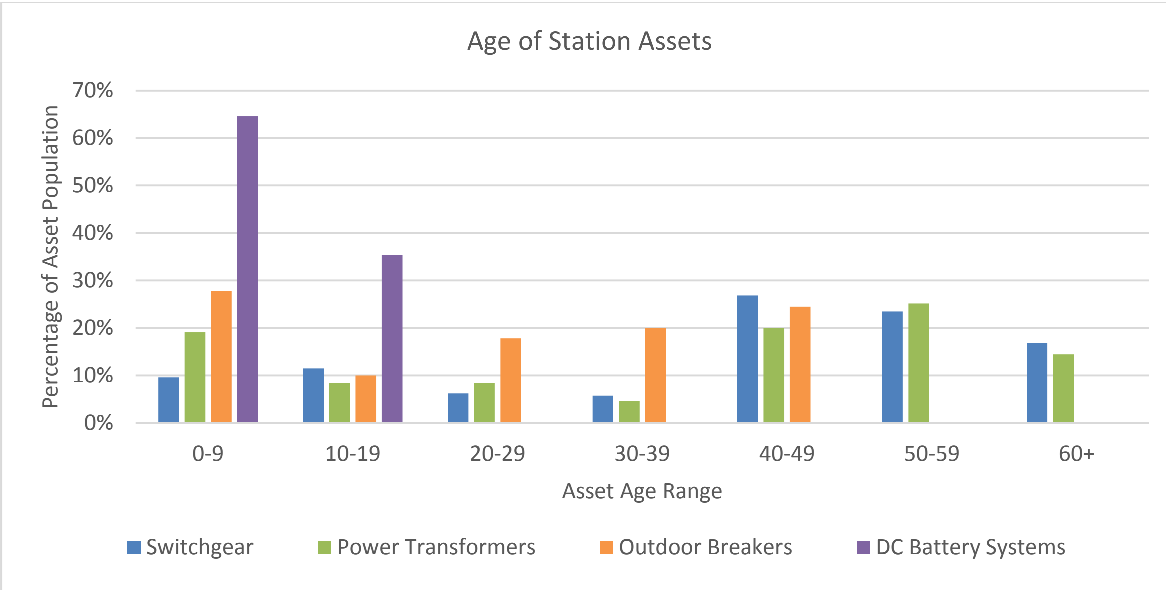


Figure 24: Stations Assets Demographics as of 2017

Within its stations asset classes, Toronto Hydro performs ACA analysis on its 215 power transformers as well as various types of its more than 1,600 circuit breakers. With the exception of 90 standalone outdoor circuit breakers, circuit breakers are contained inside one of Toronto Hydro's 209 switchgear and are considered components of their parent switchgear. Therefore, ACA performed on breakers helps serve as a proxy for switchgear condition.

Figure 25 shows that 90 percent of Toronto Hydro's air-blast circuit breakers, 66 percent of its oil circuit breakers, 58 percent of KSO oil circuit breakers, 56 percent of air-magnetic circuit breakers, 15 percent of SF_6 circuit breakers, and 6 percent of vacuum circuit breakers show signs of at least moderate deterioration. Accordingly, renewal of switchgear containing air-blast circuit breakers and oil circuit breakers are heavily targeted in the Stations Renewal Program (Exhibit 2B, Section E6.6). Similarly, standalone outdoor KSO circuit breakers are prioritized for renewal in the proposed program. Figure 25 shows that 33 percent of Toronto Hydro's station power transformers show signs of at least moderate deterioration. The need for transformer renewal is underscored by a recent surge in the number of units requiring reactive replacement.

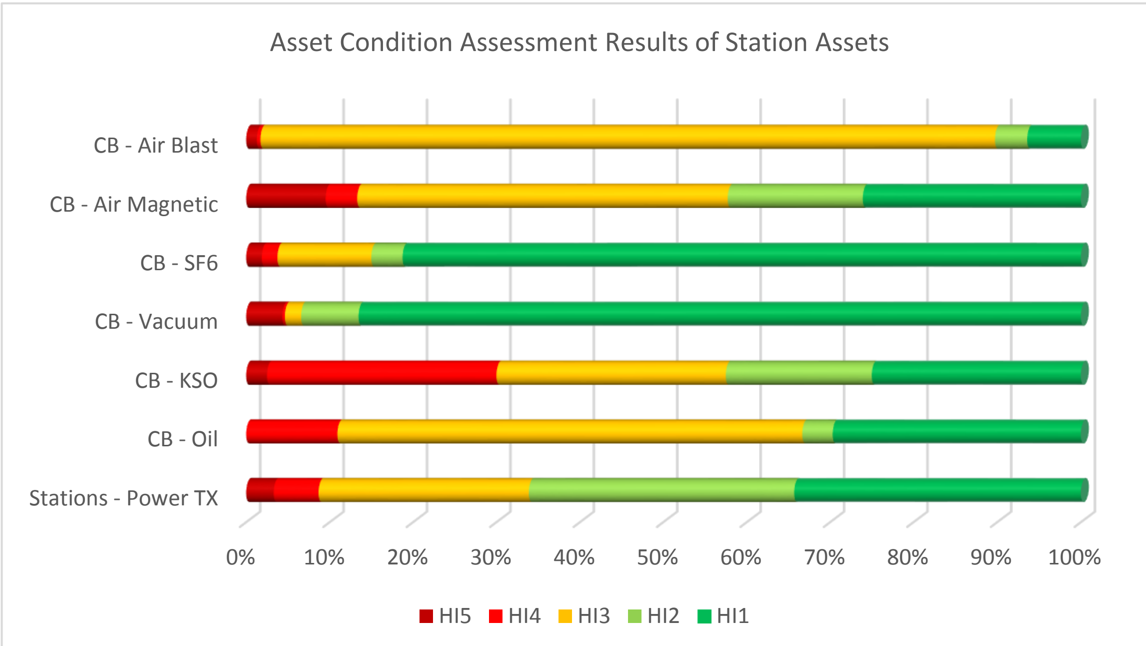


Figure 25: Asset Condition Assessment of Station Assets

Other key asset management performance measures that are relevant to the stations are include:

- **Oil Deficiencies**: During the 2015-2017 period, Toronto Hydro found on average 22 station transformers with oil deficiencies per year. Assets replaced in the Station Renewal program (Exhibit 2B, Section E6.6) and Reactive and Corrective Capital program (Exhibit 2B, Section E6.7) will include assets exhibiting oil deficiencies found during inspections.
- **Priority Deficiencies**: Station assets include power transformers, circuit breakers, switchgear, SCADA systems, relays, batteries and chargers, SCADA telemetry or control equipment, station alarms, DC panels, station heating, ventilation systems and sump pumps, which are installed across Toronto Hydro's 154 MSs[19] and 35 TSs (excluding Copeland TS). From 2013 to 2017, Toronto Hydro issued more than 4,000 work requests to address failing or failed station assets.
- **PCBs**: As of 2017, approximately 450 pieces of stations equipment, including power transformers and oil-filled breakers, contain or are at risk of containing PCBs. Through testing as part of the Preventative and Predictive Station Maintenance program (Exhibit 4A, Tab 2,

[19] Supra note 14.

Schedule 3), replacement under the Stations Renewal program (Exhibit 2B, Section E6.6) or decommissioning following voltage conversion and MS decommissioning, Toronto Hydro endeavours to eliminate the risk of PCB-contaminated oil spills by 2025. In certain instances, coordination with the Stations Expansion program (Exhibit 2B, Section 7.4) is required to remove station assets with oil containing PCBs.

D2.2.4.1 Stations Legacy Equipment

Toronto Hydro has many legacy station assets currently in operation, which are being phased out through capital renewal plans, as discussed in the Stations Renewal Program (Exhibit 2B, Section 6.6). Legacy assets include: (i) non-arc-resistant brick and metalclad switchgear; (ii) air-blast, oil, KSO oil, and air magnetic circuit breakers; (iii) DACSCAN MDO-11, D20 ME, D20M++, and MOSCAD RTUs; electromechanical pilot-wire relays; and (iv) copper communications cable.

Oil and KSO oil circuit breakers are legacy assets which also present several risks including a safety risk to Toronto Hydro personnel, risk of collateral damage to adjacent station equipment, and in some cases a safety risk to the public or an environmental risk. Both oil and KSO oil circuit breakers contain oil, which may catch fire or even explode upon failure of the asset. KSO oil circuit breakers can also contain PCBs.

D2.2.4.2 Stations Major Assets Failure Characteristics

Table 5 below provides a brief overview of the failure modes and impacts of station asset failures. Typically, failure of these assets results in power outages to all customers supplied by the affected station bus, or even the entire station. In addition to power outages, station asset failures can lead to extensive and irreparable damage.

Table 5: Station Assets Failure Modes

Asset	Failure Mode	Effects
Switchgear	a) Internal arcing occurs, due to a bus fault or circuit breaker failure.	a) Customers supplied by switchgear suffer a prolonged power outage. Arcing damages switchgear.

Asset	Failure Mode	Effects
Power Transformer	a) Oil insulation failure. b) Paper insulation failure. c) Bushing failure causes flashover.	a) Power outage to entire station. Potential internal arcing, which risks inducing fire or explosion. b) Power outage to entire station due to low or fluctuating voltage, or internal fault. c) Power outage to entire station, and flashover damages transformer.
KSO Circuit Breaker	a) Internal arcing occurs, due to internal fault or failure to interrupt fault current. b) Breaker fails to open on a fault, no internal arcing occurs. c) Bushing failure causes flashover. d) Breaker fails to close.	a) Power outage to entire station switchgear. Arcing damages breaker and risks inducing fire or explosion. b) Power outage to entire station switchgear. c) Power outage to entire station switchgear, and flashover damages breaker. d) Feeder cannot be supplied from the station switchgear. Distribtuion system is under contingency.
DC Battery System	a) DC charger system fails. b) DC battery fails.	a) All station protection and control capability is lost after 8 hours when the battery has depleted. Station is then rendered inoperable. b) Station is noncompliant with Section 10.7.1 of the Transmission System Code. Should either the DC charger system or station service supply be out of service, then the station is rendered inoperable.

D2.2.5 Metering

Toronto Hydro utilizes several different meter types in order to ensure the reliable measurement of electricity acquired by the utility through the provincial transmission system and distributed to its customers. These include: (i) Residential and Small Commercial & Industrial; (ii) Interval; (iii) Suite metered; and (iv) Wholesale applications.

- **Residential/Small Commercial & Industrial**: Toronto Hydro must continually upgrade its residential metering system to ensure that it continues to receive vendor support and is capable of enabling features on newer generation meters. Toronto Hydro plans to implement a new version upgrade of this system in 2021. To date, these meters represent 88 percent of Toronto Hydro's meter population.
- **Interval**: Toronto Hydro plans to upgrade the Interval Metering system, ITRON Enterprise Edition ("IEE") to continue to successfully meter Toronto Hydro's interval metered customers (those with a demand of 50 kW or above) over the 2020-2024 period. In 2011, Toronto Hydro had 3,300 Interval metered customers on IEE, which increased to 7,000 as of 2017. Continued growth in IEEE uptake is expected due to the decommissioning of the 2G network, and the consequent conversion of Toronto Hydro's own 2G network to 4G technology.
- **Suite Metering**: These meters represent the individually metered multi-residential buildings. The utility is legally obligated to provide suite meter installation services. Toronto Hydro offers this service in a competitive environment, and is also the provider of last resort in the event that the condominium chooses not to secure a third party meter service provide. Currently, there are approximately 79,000 suites that are individually metered by Toronto Hydro and about 3,000 multi-residential buildings that are metered by one bulk meter. Toronto Hydro plans to continue to offer its suite metering services to new customers along with retrofit upgrades over the 2020-2024 period.
- **Wholesale**: Toronto Hydro plans to upgrade its wholesale revenue meters at all applicable wholesale metering points to comply with the metering standards mandated by Measurement Canada and the Independent Electric System Operator ("IESO") Market Rules during the 2020-2024 period. These meters are installed at each of Toronto Hydro's transfer stations, and are used by Toronto Hydro to purchase power and to validate consumption with the IESO.

Toronto Hydro must maintain its fleet of meters in order to comply with both Measurement Canada and OEB mandates such as billing accuracy, estimated bills, and meter seals. In this regard, Toronto Hydro re-seals batches of meters to ensure accuracy and reactively replaces failed or non-communicating meters to ensure compliance. Toronto Hydro's meter population is aging with the majority of the residential and small C&I meter population reaching and exceeding 15 years of age during the 2020-2024 filing period.

D2.2.5.1 Metering Major Assets Failure Characteristics

Table 6 below provides a brief overview of the failure modes and impacts of metering asset failures.

Table 6: Metering assets failure mode

Asset	Failure Mode	Effects
Energy Meter	a) Communications Failure	a) Bills must be estimated or meter manualy read
Instrument Transformer	b) Device Failure	b) Meter reads would be incorrect due to failed instrument transformers

D2.3 System Utilization

Toronto Hydro completes an annual load forecast of station bus capacity to plan for short and long term load growth, additional capacity requirements to serve customers, and contingency scenarios such as planned work or loss of supply. This load forecasting process is further explained in Section D3.1.1. To prevent system overloading which may lead to asset failures, the peak utilization of a bus should not reach or exceed 100 percent of its rated capacity for extended periods of time.[20] Bus capacity rating is determined based on the ratings for all of its associated equipment and a Limited Time Rating[21] for upstream equipment provided by Hydro One. Forecasting is performed at the bus level.

[20] For planning purposes a 95 percent loading threshold is used for the downtown region, while a 100 percent bus loading threshold is used for the Horseshoe. This difference in the threshold is due to the fact that there is more load transfer capabilities in the Horseshoe area than the downtown area so more time is required to make plans for downtown capacity constraints, than for Horseshoe capacity constraints. Further details of the load forecasting can be found in Section D3.1.2.1 Decision Support Systems as well as E7.7 Stations Expansion.

[21] Limited Time Rating ("LTR"): With respect to transformers, a limited time rating is a set of 15-minute, 2-hour, and 10-day MVA ratings determined by Hydro One in order to accommodate shorter time interval loading periods without causing equipment damage. All of Toronto Hydro's buses are supplied via at minimum two transformers operating in parallel. For bus capacity planning purposes, Toronto Hydro utilizes the 10-day LTR rating provided by Hydro One which is the maximum MVA the most limiting transformer can supply for a 10-day period with the other transformer out-of-service.

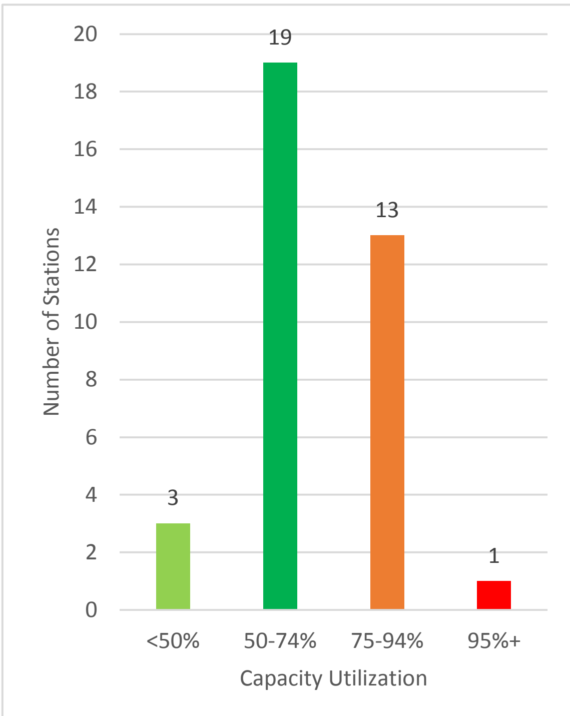


Figure 26: Forecasted Station Loading in 2020

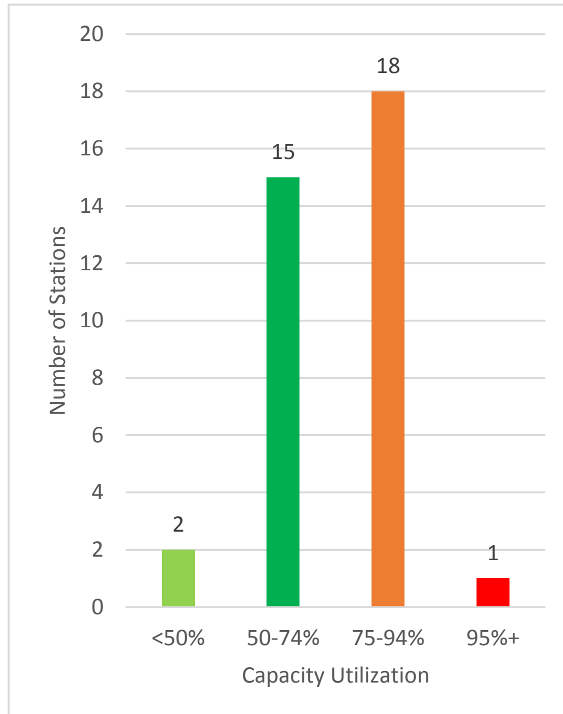


Figure 27: Forecasted Station Loading in 2025

From a station capacity standpoint, by 2020, 39 percent of Toronto Hydro stations will experience loading of 75 percent or higher, with one station that is forecast to be near capacity. By 2025, Toronto Hydro anticipates that the aforementioned percentage will increase to 53 percent, with one station expected to exceed its capacity. Operating stations at 100 percent capacity would severely limit the utility's flexibility to manage abnormal system states (planned or unplanned). In a worst case scenario, Toronto Hydro would be unable to maintain or replace a failing or failed asset.

More specifically, Toronto Hydro must also ensure that each of its stations has sufficient capacity to connect new or existing customers without sacrificing system reliability or operational flexibility for existing customers. Otherwise, extensive load transfers must be pursued through the Load Demand Program solely to free up the capacity needed to connect new customers without overloading a bus. Although this limit precedes station capacity, it is the primary driver for the need for extensive load transfers or station expansion projects so that new customer connections can be made. To this end, Toronto Hydro uses a second capacity metric, System Capacity (Exhibit 2B, Section C3.3), which forecasts that 13 to 14 of its stations will be unable to connect new large customers over 2020-2024, unless the work proposed under its Station Expansion (Section 7.4) and Load Demand (Section 5.3) programs is completed.

To mitigate overloading at the stations and free up capacity to connect new large customers, Toronto Hydro analyzes each station's load forecast as well as available capacity in the area to resolve loading problems. Possible resolutions are to plan load transfers, upgrade existing components, or expand the station. A large number of limitations and considerations must be taken into account in implementing these solutions, including:

- incompatible system voltages (e.g. 27.6 kV vs. 13.8 kV);
- incompatible system types (e.g. radial versus looped, or overhead versus network);
- availability of civil infrastructure;
- availability of feeder positions;
- environmental or civil barriers (e.g. rivers, highways ravines); and
- relative cost between relief options.

Due to all these various considerations, every station must be individually analyzed to determine an appropriate resolution.

On the feeder level, Toronto Hydro typically plans new customer connections or customer load increases by analyzing the area where the additional load requirements are emerging. Similar limitations and considerations at both the feeder level and station level must be accounted for in the planning process. This process is largely reactive given the significant uncertainty in forecasting feeder loading, because it is difficult to predict exactly where new loads will materialize and there are multiple feeders which can potentially connect new loads.

On the asset level, Toronto Hydro frequently reviews the system in areas of high capacity utilization or areas of poor reliability to determine what work can be undertaken to improve the system. It is difficult to monitor every asset in the system to ensure it is optimally utilized. Nonetheless, Toronto Hydro has initiatives in place which will install new infrastructure and allow more assets to be closely monitored. Examples of such initiatives are network monitoring, stations control and monitoring replacements and new installations, and power transformer and switchgear replacements. These initiatives help prevent overloading which may cause premature equipment failure.

D3 Asset Lifecycle Optimization

Section D1 provided an end-to-end overview of Toronto Hydro's distribution system Asset Management Process ("AM Process"), from strategic planning to execution and reporting. Section D2 provided an overview of the current state of the major distribution assets that the utility manages.

- **Section D3** focuses on key factors that guide and influence investment pacing and prioritization decisions within the AM Process.
- **Section D3.1** provides an overview of the basic replacement, refurbishment, and maintenance approaches that Toronto Hydro applies to major asset classes to optimize the value derived from individual assets over their lifecycles. These asset lifecycle optimization practices are the fundamental building blocks for asset management and investment planning at Toronto Hydro.
- **Section D3.2** describes the ways in which the utility considers and manages failure risk in its AM process. Risk management takes various qualitative and quantitative forms and is fundamental to deriving expenditure plans that support the optimization of future outcomes within a constrained budget.
- **Section D3.3** describes the ways in which the utility considers and manages capacity risk in its AM process.
- **Section D3.4** describes the expenditure program planning process that Toronto Hydro uses to derive a capital expenditure plan from its AM Process.

For an overview of how the practices discussed in this section informed Toronto Hydro's 2020-2024 Capital Expenditure Plan for system-related investments, see Section E2.2.

D3.1 Asset Lifecycle Optimization Practices

As noted in Section D1, the broad objective of Toronto Hydro's AM Process is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders. At the most fundamental level, this value is realized by consistently implementing prudent lifecycle optimization practices tailored to specific asset classes. These practices serve as guidelines for when and how to inspect and intervene on a specific asset, where intervention includes asset maintenance, refurbishment, and replacement.

Toronto Hydro's lifecycle optimization practices are the result of many decades of experience managing major distribution assets across a dense, mature, and congested major city that is served by various system designs and configurations. These practices take into account the various attributes of an asset class, including, but not limited to: (i) the intended functionality of the asset in the distribution system; the various modes of deterioration and failure over the asset's typical lifespan; (ii) the potential impact of various failure modes on distribution service; and (iii) the typical costs and customer impacts of intervention.

The following two sub-sections describe Toronto Hydro's asset lifecycle optimization practices, beginning with the utility's foundational maintenance and refurbishment practices, followed by a description of the utility's typical asset replacement practices for major asset classes.

D3.1.1 Maintenance and Refurbishment Practices

As part of its overall asset management process, Toronto Hydro aims to ensure the continuous serviceability (i.e. usefulness) of assets over their typical or expected useful lives, and to extend an asset's serviceability when it is feasible and economical to do so. Asset maintenance and refurbishment practices are the means by which Toronto Hydro supports these objectives.

D3.1.1.1 Reliability Centered Maintenance

Toronto Hydro typically conducts inspection and maintenance tasks on a fixed cycle. These activities are focused on preserving and maximizing an asset's performance over its expected useful life while mitigating a wide variety of system risks. Maintenance activities support the minimization of overall lifecycle costs and account for factors such as the safety of Toronto Hydro employees and the public, responsible environmental stewardship and associated obligations, and compliance with statutory and regulatory requirements.

Toronto Hydro's foundation for maintenance planning is Reliability Centered Maintenance ("RCM"), an established engineering framework for the maintenance of assets throughout their lifecycles. The RCM framework determines failure management policies for any physical asset in its present operating context to maximize useful life and reliability based on the asset's function and the consequences of functional failure, including the asset's criticality to the distribution system. The output of an RCM analysis includes failure mode analysis, which is used to identify proactive tasks (with associated time intervals) that help to predict or prevent failures from occurring. It also focuses on preventing failures where consequences are most severe. Toronto Hydro initially adopted an RCM framework in 2003 and subsequently reviewed and updated its outputs in 2011 and over the 2016 and 2017 period, ensuring compliance with the Society of Automotive Engineers ("SAE") standards SAE JA-1011[1] and SAE JA-1012.[2]

RCM is a comprehensive approach to the lifecycle maintenance of distribution system assets. Initially developed in the airline industry to manage high maintenance costs and high failure rates, RCM has allowed Toronto Hydro to increase its analytical capabilities in determining the optimal level of maintenance expenditures and the appropriate time of intervention for a specific asset class. The RCM framework incorporates a thorough analysis of assets going beyond manufacturer's requirements to evaluate functional failures under utility-specific operating conditions. The analysis identifies and categorizes consequences of failure (i.e. safety, cost, reliability). Maintenance programs are subsequently set to mitigate these consequences by establishing recommended optimal asset intervention timelines.

The benefits of RCM include:

1) A structured and data-driven targeted maintenance program;
2) Reduced efforts and costs expended on maintenance programs with little resultant value; and
3) Increased reliability due to the effectiveness of the failure prevention program.

Toronto Hydro leverages the RCM framework, in combination with the OEB's Minimum Inspection Requirements and the continuous monitoring and assessment of asset performance, to derive its maintenance programs and associated expenditure plans. The expenditure plans for these maintenance programs can be found in Exhibit 4A, Tab 2, Schedules 1-3. Table 1 below provides a summary of the maintenance plans for the major asset types on each part of Toronto Hydro's distribution system.

[1] Standard SAE JA-1011 (Evaluation Criteria for Reliability Centered Maintenance (RCM) Processes) outlines requirements for an RCM analysis process. This standard is intended to be used to evaluate any process that purports to be an RCM process. The standard also specifies the minimum characteristics that a process must have in order to be an RCM process.
[2] SAE JA-1012 ("A Guide to the Reliability-Centered Maintenance (RCM) Standard") amplifies and clarifies each of the key criteria listed in SAE JA-1011, and summarizes additional issues that must be addressed in order to apply RCM successfully. It does not provide an additional list of requirements that must be met, rather it provides guidance on how to meet the requirements of SAE JA-1011. The resulting analysis produces failure management policies forming part of the maintenance program that are deemed to be the most cost and risk effective at sustaining asset performance in accordance with the company's risk tolerance level.

1 **Table 1: System Maintenance Practices**

System	Asset Class/Type	Planned Maintenance Activities	Toronto Hydro Cycle
Overhead	*Pole-top Transformer*	Line Patrols	3 Years Visual, 1 Year Infrared
	Distribution Poles	Line Patrols	3 Years Visual
		Wood Pole Inspection & Treatment	10 Years
	Primary Conductors	Line Patrols	3 Years Visual, 1 Year Infrared
		Tree Trimming	1-5 Years, with the majority being 2-3 Years
	Secondary Conductors	Line Patrols	3 Years Visual
	Switches	Line Patrols	3 Years Visual, 1 Year Infrared
		Maintenance (SCADA-Mate & Gang-Operated)	4 Years
		Battery Replacement for Switches (SCADA-Mate & Gang-Operated) and Repeater Radio	3 Years
	Insulators	Insulator Washing (for Porcelain)	6 Months
Underground	*Padmounted Transformer*	Inspection (Civil + Electrical)	3 Years
	Submersible Transformer	Vault Inspection (Civil + Electrical)	3 Years
	CRD Transformer		1 Year
	URD Transformer		
	Building Vault Transformer	Inspection (Civil + Electrical)	3 Years
	Padmounted Switch	Inspection (Civil + Electrical)	1 Year
		Battery Replacement	3 Years
	Cable Chamber	Cable Chamber	10 Years
	Cables	Contact Voltage Scanning	1 Year
Network	*Network Transformer*	Network Vault Inspection - Electrical	1 Year
		Network Vault Inspection - Civil	6 Months
		Reverse Power Breaker Overhaul	3 Years
		Protector Top Cleaning	1 Year

System	Asset Class/Type	Planned Maintenance Activities	Toronto Hydro Cycle
		Network Protector Overhaul - HV[3]	4 Years
		Network Protector Overhaul - LV[4]	5 Years
Station	*Station TS & MS Facilities*	Monthly Inspections	1 Month
		Seasonal Detailed Inspection	6 Months
	Circuit Breaker (All Types) & Switch	Maintenance	4 Years
	Bus Disconnect Switches		
	B-Bus	B-Bus Cleaning	4 Years
	Power Transformer	Equipment Maintenance	4 Years
	DC Battery & Charger	Seasonal Detailed Inspection	6 Months
	Compressed Air System	Station Compressed Air System Maintenance	6 Months
	Station Alarms in Downtown	Alarm Testing	1 Year
	Pilot Wire	Pilot Wire Protection	6 Years

D3.1.1.2 Summary of Maintenance Programs and Activities

Asset maintenance programs (Exhibit 4A, Tab 2, Schedules 1-5) are grouped into four major categories based on their functionality, as shown below:

- Preventative Maintenance;
- Predictive Maintenance;
- Corrective Maintenance; and
- Emergency Maintenance.

The framework of asset preventative and predictive maintenance programs is driven primarily by regulatory requirements, as mandated by the OEB's Distribution System Code Minimum Inspection Requirements (Appendix C to the Distribution System Code).

In addition, preventative and predictive maintenance programs, and maintenance activities are scheduled to be closely in line with the output of RCM analyses, which is performed on a per-asset class basis and informed by condition-based maintenance principles and an emphasis on maximizing

[3] High Voltage ("HV")
[4] Low Voltage ("LV")

productivity. RCM is an established engineering framework that determines failure management policies for any physical asset in its present operating context to maximize reliability based on the asset's function and criticality to the distribution system. The output of RCM consists of proactive tasks and associated time intervals in order to predict or prevent failures from occurring. Condition-based maintenance promotes the adjustment of maintenance frequencies based on the condition of a particular asset class as opposed to a strict frequency based approach.

1. Preventative Maintenance

This type of maintenance involves inspections and maintenance tasks on a fixed cycle, which emphasizes preserving asset performance over its expected life, and maintaining public and employee safety. Maintenance cycles are defined based on the mean time between failures of a given asset class, and are intended to maintain the asset before it is statistically likely to fail. An example of a preventative maintenance task is the inspection of wooden utility poles, which is carried out on a ten-year cycle. For additional information, refer to Exhibit 4A, Tab 2, Schedules 1-3.

2. Predictive Maintenance

Predictive maintenance involves the testing and inspection of equipment for predetermined conditions that are indicative of a potential failure, and then undertaking maintenance tasks to prevent those failures. Predictive maintenance is the most effective maintenance approach for those assets that exhibit conditions that can be identified, practically monitored, and corrected prior to failure. An example of a predictive maintenance task is Dissolved Gas Analysis of power transformer mineral oil, which identifies the presence of dissolved gases and other chemical compounds in the oil as an indication of potential failure modes (e.g. overheating, excessive moisture, or breakdown of the insulating paper). Corrective maintenance tasks can then be undertaken to correct the deficiencies to avoid equipment failure. For additional information, refer to Exhibit 4A, Tab 2, Schedules 1-3.

3. Corrective Maintenance

Corrective maintenance involves repairing or replacing equipment after a deficiency has been reported during the execution of preventative or predictive maintenance tasks or other planned work. These tasks typically involve a short planning horizon since a portion of the distribution system is faulted, isolated, or in a substandard condition thereby putting the system at risk. Since defective equipment is a major contributor to SAIFI and SAIDI, corrective maintenance emphasizes restoring assets to an acceptable level of operation, thereby improving system reliability. Examples of corrective maintenance tasks included: (i) the replacement of a cracked porcelain insulator; (ii) the repair of a broken guy wire; (iii) the removal of vegetation growing on a pole and into an overhead line; or (iv) the replacement of a conductor splice. These actions are undertaken in response to line patrol findings (and infra-red inspections) as part of the Preventative and Predictive Maintenance programs (Exhibit 4A, Tab 2, Schedules 1-3).

Corrective maintenance can also be required as a result of an unplanned system event or emergency. For example, a faulted section of underground cable that had been isolated from the system during an emergency response would be unearthed and replaced as a corrective maintenance action. For additional information, refer to Exhibit 4A, Tab 2, Schedules 4-5.

4. Emergency Maintenance

Emergency maintenance involves the urgent repair or replacement of equipment that has failed or is in imminent danger of failure, in order to restore or maintain power. This type of maintenance may also involve an immediate response to a safety or environmental hazard. It emphasizes safe and prompt response to restore service or prevent a service disruption. An example of emergency maintenance would be restoration of service to customers that have lost power due to a broken tree branch on the overhead lines. Refer to Exhibit 4A, Tab 2, Schedule 5 for further information.

The details of how the asset inspections and capital and maintenance programs are related are summarized below as part of the deficiency capturing process in Figure 1.

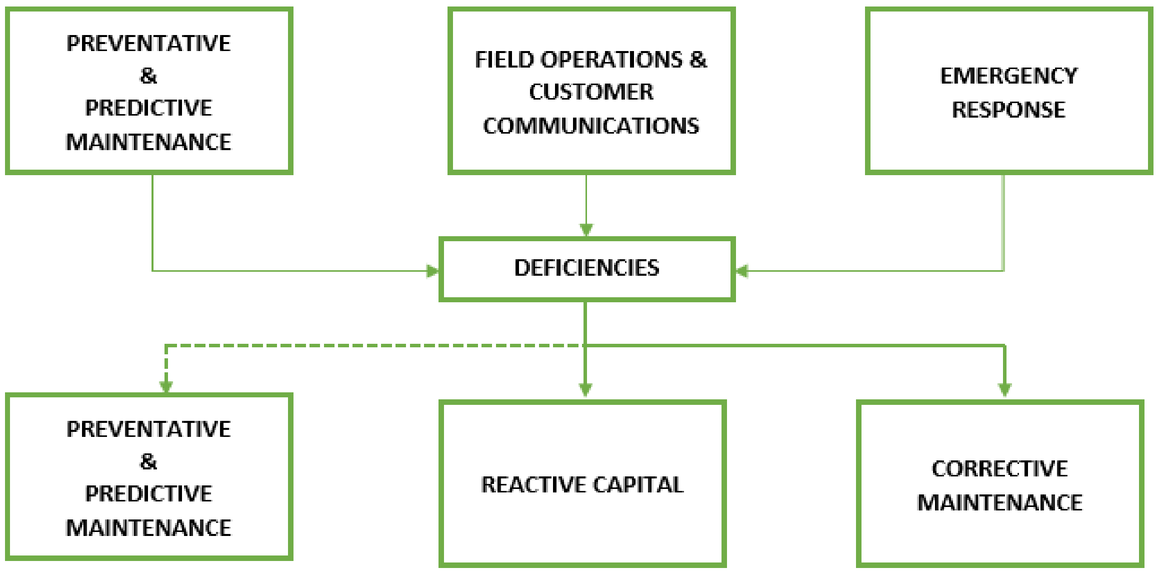


Figure 1: Deficiency Capturing Process

Distribution system events such as power outages are initially addressed through the Emergency Response program (Exhibit 4A, Tab 2, Schedule 5). The cost of any capital work (e.g. asset replacement) carried-out during an Emergency Response event is captured in the Reactive Capital segment (See Exhibit 2B, Section 6.7 Reactive and Corrective Capital program). An Emergency Response event can also result in follow-up work to be carried out via the Reactive Capital segment.

The more substantial source of Reactive and Corrective Capital work is the identification of asset failures and deficiencies through maintenance activities and daily utility operations, including:

- Toronto Hydro's Preventative and Predictive Maintenance programs systematically identify asset failures and priority deficiencies through regularly scheduled system maintenance activities. Through the "find it and fix it" practices, on-site repair of minor deficiencies is carried out. For more details on these programs, refer to Exhibit 4A, Tab 2, Schedules 1-3**.**
- Failures and deficiencies are also identified through daily field operations and customer contacts. These include observations by field crews and system operators during the normal course of operations, external emails, customer inquiries requiring field assessment and follow up including phone calls received from the customer service team, and meter errors captured through internal data collection systems.

These processes and activities can result in both capital and operating expenditures (e.g. corrective tree trimming). The Corrective Maintenance program (Exhibit 4A, Tab 2, Schedule 4) is the operational counterpart to the Reactive Capital segment.

Toronto Hydro has an established internal process for reviewing all work inquiries from these sources to validate the need for reactive intervention, assess the nature of reactive intervention required (i.e. capital versus maintenance), and the level of urgency/priority to be assigned to each item. Prioritization of the asset deficiencies identified as part of the work request process is based on the urgency of the work and how quickly it needs to be resolved. The work requests are classified into three categories (P1, P2, and P3) as discussed in Section D3.2.1.3 and illustrated in Figure 2:

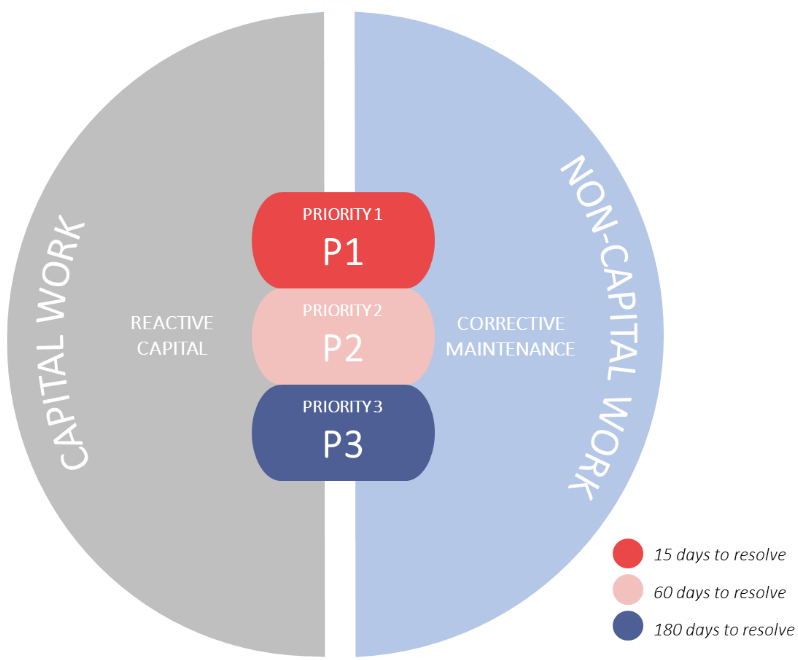


Figure 2: Work Request Prioritization

D3.1.1.3 Impact of System Renewal on Maintenance Planning

Toronto Hydro routinely assesses the impact of its system renewal investments on preventative and predictive maintenance plans. The directional relationship between asset replacement and planned maintenance is largely dependent on the maintenance requirements for the assets being removed and installed.

A significant portion of maintenance program expenditures is directed toward activities that are independent of system renewal programs, including: (i) routine maintenance to preserve asset performance over its expected life; (ii) vegetation management to maintain minimum clearance requirements for overhead conductors and equipment; (iii) cyclical patrols and inspections undertaken to comply with minimum requirements under the Distribution System Code; (iv) corrective maintenance activities to address deficiencies caused by material and equipment deterioration, and animals, pests, vegetation, and other environmental influences; and (v) emergency maintenance following severe weather and storm damage. Maintenance programs also provide the asset condition information necessary to plan system renewal programs.

Certain types of system renewal investments can reduce planned maintenance costs in specific circumstances. Generally, the removal of legacy and functionally obsolete assets from the system can eliminate the need for maintenance activities or higher maintenance frequencies that are specific to the legacy asset type. At the same time, new equipment and new standards and practices may introduce incremental maintenance requirements. The utility considers maintenance requirements when evaluating new products and developing new standards as part of its continuous Standards and Practices Review activities.

Toronto Hydro anticipates that system renewal programs targeting legacy assets such as vacuum circuit breakers, non-submersible network protectors, reverse power breakers, automatic transfer switches, porcelain insulators, and rear lot construction, will contribute to a gradual and modest reduction in costs related to legacy equipment maintenance as the population declines and the assets are replaced with equipment that typically requires lower maintenance costs or is maintenance free. System service programs such as Network Condition Monitoring and Control (Section E7.3) are also expected to contribute to modest reductions in the amount of on-the-ground maintenance required for the network system. Due to the overall age and condition of the system, remaining volume of obsolete legacy assets, and increasing pressure from adverse weather events, Toronto Hydro does not anticipate a decline in corrective maintenance, emergency maintenance, or reactive capital expenditures in the forecast period.

D3.1.1.4 Overview of Toronto Hydro's Refurbishment Practices

Both maintenance and refurbishment involve intervening on an asset to maintain or maximize its serviceability. Maintenance consists of activities that are necessary to ensure the reliable operation of an asset over its expected useful life. Refurbishment differs from maintenance in that it involves renovating an asset to extend its serviceable life. For example, tree trimming is a form of maintenance, while rebuilding a vault roof is a form of refurbishment.

Toronto Hydro's refurbishment efforts are mainly focused on assets that have been taken out of service (e.g. through a renewal project or as a result of failure). An asset may be considered for refurbishment if it meets specific criteria and is in good enough condition to be reintroduced into the system after appropriate testing. This is done for major asset types like transformers, network protectors, and switches. Toronto Hydro evaluates major equipment returned from the field, and categorizes it based on the following criteria:

1) **Decommissioned equipment that remains operational:** Should a major asset such as a station power transformer be removed from the system as part of a system renewal project, or due to station decommissioning, Toronto Hydro will inspect and test the equipment to determine if it is still fit for service. If the equipment is still operational, the utility will keep it as a spare in case of reactive replacements.
2) **Repair of failed or defective equipment:** Equipment will be repaired or refurbished if it meets the following criteria: (i) it is under warranty; (ii) it is a critical spare (e.g. 4 kV assets); (iii) transformers less than 10 years old; (iv) network protectors less than 15 years old; (v) overhead switches less than five years old; or (vi) underground switches less than 15 years old. An example would be load conversion, where 4 kV equipment is removed from the system and replaced with the current standard. The removed assets are typically refurbished and kept as spares due to the scarcity of these obsolete asset types and in the event that other 4 kV assets on the system need to be replaced reactively.

Equipment that does not meet the specific criteria for re-use listed above will be scrapped.

Where appropriate, Toronto Hydro undertakes targeted refurbishments in the field to maximize the serviceable life of existing assets. For example, as mentioned above, the utility will rebuild a deteriorated vault roof, extending the useful life of the entire vault. Another example is the refurbishment of a particular line section by replacing legacy porcelain insulators with new polymeric equivalents.

D3.1.2 Asset Replacement Practices

The decision to replace an asset can result from many drivers, including asset failure, deterioration and failure risk, functional obsolescence, historical performance, standards alignment, planning and execution efficiencies, capacity requirements, and third-party requests.

Failure, failure risk, and functional obsolescence are the three most significant trigger drivers for asset replacement in the System Renewal investment category. Renewal-driven replacement practices for specific asset classes can range from primarily reactive replacement, where replacement largely occurs when the asset has failed (i.e. it can no longer serve its intended function), to primarily proactive replacement, where the consequence of failure for an asset class (i.e. the asset's criticality) is high, making it unacceptable to run the asset to failure under most circumstances.

While a few asset classes are situated at the far ends of the reactive-proactive spectrum, Toronto Hydro manages most major asset classes using a blend of reactive and proactive replacement strategies. This approach reflects how the risk profile and specific performance challenges within and across asset classes evolves over time, particularly in a large, dense, and congested city served by a variety of highly utilized systems inherited from several predecessor smaller utilities. It also reflects variability in the location-specific criticality of individual assets across the system. The proportion of assets the utility replaces proactively is related to the utility's performance objectives and the risk assessments underlying projected performance.

Tables 2 to 6 below provide an overview of Toronto Hydro's current replacement practices for assets on each part of the distribution system.

1 **Table 2: Summary of Overhead System Asset Replacement Practices**

Asset	Asset Replacement Practices
Poles	Toronto Hydro manages the risk profile of its pole population by proactively replacing poles in alignment with condition demographics and other risk factors (e.g. legacy asset replacement needs). Poles are replaced on an individual basis or as part of area rebuilds. Poles are prioritized for replacement based on condition, age, criticality, and relationship (e.g. proximity) to other high-risk assets. In the event poles fail while in service, Toronto Hydro replaces them reactively. Due to the urban environment in which the Toronto Hydro operates, the utility has a very low risk appetite for catastrophic pole failure (i.e. collapse of pole) and designs its pole testing, inspection and reactive replacement programs to substantially mitigate this risk.
Pole-top Transformers	Toronto Hydro manages the risk profile of its pole-top transformer population through proactive and reactive replacement. The utility prioritizes transformers that present heightened failure risks based on condition, age, area reliability, and environmental risks (e.g. oil leaks containing polychlorinated biphenyls ("PCBs")). Due to the low individual criticality of a typical, PCB-free pole-top transformer, Toronto Hydro will generally replace these assets reactively or as part of a larger proactive area rebuild project when there are economies of scale. As noted in Sections D2 and E2, Toronto Hydro is forecasting a greater rate of proactive pole-top transformer replacement in 2020-2024 due to demographic failure risks (i.e. significant age backlog) and PCB oil spill risk for units manufactured in 1985 and earlier.
Overhead Switches	Toronto Hydro does not have a dedicated proactive renewal strategy for overhead switches. Where appropriate, switches are replaced as part of a planned area rebuild, or else reactively upon failure due to age, condition, or external factors. Where safety risks are identified for a type or class of switches, the utility executes planned replacements of these assets to mitigate the risks.

Asset	Asset Replacement Practices
Overhead Conductors (primary and secondary)	Toronto Hydro does not have a dedicated proactive renewal strategy for overhead conductors. Where appropriate, conductors are replaced as part of a planned area rebuild (e.g. upgrade to tree-proof conductor in heavily treed areas) or reactively upon failure due to age, condition, or external factors.

1 **Table 3: Summary of Underground System Asset Replacement Practices**

Asset	Asset Replacement Practices
Underground Cables (Polyethylene)	Toronto Hydro manages the risk profile of its underground cable population by both proactively and reactively replacing polyethylene (e.g. cross-linked polyethylene ("XLPE")) cables. The utility proactively replaces aged or poor performing cables through neighbourhood rebuild projects to manage significant reliability risks associated with these assets, mainly targeting poor performing direct-buried cables in the Horseshoe area. Otherwise, if these cables fail while in service, they are repaired or replaced reactively.
Underground Cables (Lead)	Underground lead cables have traditionally been replaced reactively on the downtown underground distribution system. With increasing reliability, safety, and operational risks associated with lead cable (i.e. leaking cables, congested cable chambers, increasing numbers of splices, dwindling supply and expertise), Toronto Hydro is shifting from a reactive repair and replacement strategy to a proactive strategy to gradually remove the large population of deteriorating and obsolete cable types, replacing them with modern polyethylene cables. The utility prioritizes cable replacement based on a predictive risk model. Aside from the modest proactive investments that are planned for the 2020-2024 period, these cables are repaired or replaced reactively when they fail while in service.
Underground switches	Toronto Hydro manages the risk profile of underground switches by proactively replacing them through neighbourhood rebuild projects (triggered by direct-buried cable replacement priorities), taking into consideration age, condition, and failure impact. Otherwise, switches that fail while in service are replaced reactively.

Asset	Asset Replacement Practices
Underground Transformers	Toronto Hydro manages the risk profile of its underground transformer population through proactive and reactive replacement. Underground transformers are replaced as part of planned area rebuilds (triggered by direct-buried cable replacement needs) or on an individual basis if they pose an environmental risk due to the risk of leaking oil containing PCBs and are at or past their useful life and/or in deteriorating condition. Otherwise, transformers that fail while in service are replaced reactively.
Cable Chamber	Toronto Hydro manages the risk profile of its underground cable chambers by proactively replacing assets based on condition. Historically, Toronto Hydro has replaced cable chambers reactively. However, due to the growing number of deteriorating chambers and the complexity of chamber reconstruction work, the utility is shifting to a planned renewal strategy to replace cable chambers (or rebuild cable chamber roofs) in end of serviceable life condition. Otherwise, cable chambers that fail while in service are addressed reactively.
Underground Residential Distribution ("URD")	Toronto Hydro manages the reliability performance for customers served by the URD system by proactively replacing URD assets. Toronto Hydro targets critical and obsolete URD assets in deteriorating and poor condition or past their useful life such as switching and non-switching vaults, switches, and transformers that contribute to the deterioration of system reliability. Otherwise, assets that fail while in-service are replaced reactively.

Table 4: Summary of Network System Asset Replacement Practices

Asset	Asset Replacement Practices
Network Automatic Transfer Switches ("ATS") and Reverse Power Breakers ("RPB")	Toronto Hydro reduces safety and reliability risks on the network system by proactively removing functionally obsolete ATS and RPB equipment. Toronto Hydro is replacing them with standard equipment at a pace expected to eliminate them completely during the 2020-2024 period. Otherwise, assets that fail while in service are replaced reactively.

Asset	Asset Replacement Practices
Network Units	Toronto Hydro manages the risk profile of its network unit population by proactively replacing units in alignment with condition demographics and other risk factors (e.g. safety and environmental risks). The utility proactively replaces network units with a higher risk of failure due to age, condition, obsolescence, or location (i.e. prone to flooding). Older units with obsolete "non-submersible" protectors, which make them susceptible to water ingress causing failure, are generally beyond their useful life and are at risk of leaking oil containing PCBs. The utility is aiming to reduce and eventually eliminate the population of non-submersible units due to increasing risks of flooding. Otherwise, units that fail while in service are replaced reactively.
Network Vaults	Toronto Hydro manages the risk profile of its network vault population by proactively replacing vaults or vault roofs in alignment with condition demographics and other risk factors (e.g. safety risks). Due to the complexity of vault rebuild projects, Toronto Hydro must maintain a steady pace of renewal targeting the worst condition locations. Vaults are prioritized primarily based on condition and the associated safety risks of structural deterioration, customers served, and external factors (i.e. road moratoriums). If a deteriorated vault is no longer needed due to load displacement, then the utility will decommission it. Otherwise, vaults that fail while in service are addressed reactively.
Network Cables	See Underground cables – polyethylene and lead.

1 **Table 5: Summary of Stations Asset Replacement Practices**

Asset	Asset Replacement Practices
Transformer Station ("TS") Switchgear	Toronto Hydro manages the risk profile of its TS switchgear population by proactively replacing assets to manage overall switchgear demographic risk and system reliability. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Existing units are often difficult and infeasible to safely maintain due to their design, and therefore, proactive replacement is preferred to resolve maintenance issues. Asset replacements need to be done proactively as they have long lead times to procure (e.g. 12-18 months), and design and construct (e.g. 3-4 years). Replacement prioritization is dependent on various factors, including: age, breaker condition, obsolescence, and safety. These assets can fail while in service, and in such situations, customers may experience long outages while Toronto Hydro restores power and subsequent reactively repairs or replaces the failed switchgear.
TS Oil Circuit Breakers (KSO)	Toronto Hydro manages the risk profile of its TS oil circuit breaker population by proactively replacing assets. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Asset replacements need to be done proactively as they have long lead times. Toronto Hydro replaces TS KSO oil circuit breakers based on age, condition, obsolescence, and safety and environmental risks (i.e. oil containing PCBs). Otherwise, assets are replaced reactively when they fail while in service.
Municipal Station ("MS") Switchgear	Toronto Hydro manages the risk profile of its MS switchgear population by proactively replacing them. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Asset replacements need to be done proactively due to long lead times. Existing units are often difficult and infeasible to safely maintain due to their design, and therefore, proactive replacement is preferred to resolve maintenance issues. Toronto Hydro replaces MS switchgear based on age, breaker condition assessment results, the obsolescence of the asset, and the safety and reliability risks they present. When these assets fail while in service, Toronto Hydro will first attempt to repair the unit, but depending on the severity of the fault, may replace it reactively.

Asset	Asset Replacement Practices
MS Primary Supply	MS primary supply assets (disconnect switches, cables, and circuit breakers) are proactively replaced to maintain overall condition demographics and reliability. MS primary supply assets are replaced proactively as part of MS power transformer replacement projects and may be included as part of a switchgear replacement projects. For 2020-2024, Toronto Hydro plans to target some MSs (i.e. not planned for decommissioning or transformer or switchgear replacement) for primary supply replacement as well. Prior to 2018, power transformer replacements were typically completed without replacing MS primary supply as these assets were generally replaced reactively. This change in strategy is due to many assets operating beyond their useful life and the time of required replacement. MSs targeted for primary supply replacement are prioritized based on failure risk as determined by age and configuration (e.g. direct-buried cable).
Power Transformers	Toronto Hydro manages the risk profile of its power transformers by proactively replacing assets to manage overall demographic risk and system reliability. Power transformers require long lead times (e.g. 12 months) to procure, design and construct and therefore need to be replaced as part of a steady proactive renewal program. These assets are prioritized based on age and condition.
Station Service Transformers (“SSTs”)	Toronto Hydro replaces SSTs proactively to manage age demographics and maintain reliability on the system. Asset replacement also requires long lead times and as a result, needs to be done proactively. Units are prioritized based on their age and associated environmental risk (i.e. risk of oil containing PCBs). Once these assets fail in service, the station service supply cannot afford to experience a subsequent failure as that failure would render the station inoperable. Moreover, any planned renewal or maintenance work of ancillary systems may be delayed.
Remote Terminal Units (“RTUs”)	Toronto Hydro replaces functionally obsolete RTUs proactively as they are beyond their useful life, and no longer supported by their manufacturers. These assets can be repaired within a two-week period, however, repairs cannot be maintained over the long term due to the scarcity of spare parts. These assets also have a long replacement time (e.g. 6 months) and are therefore difficult to replace reactively.

Asset	Asset Replacement Practices
Pilot-wire Relays & Copper Communication Cable	Toronto Hydro replaces these assets proactively to maintain overall condition demographics and reliability. Pilot-wire relays and copper communication cables are replaced proactively as these assets are functionally obsolete, and are no longer produced or supported by the manufacturer (i.e. lack of spare parts) making it difficult to maintain and repair the asset. Copper communication cables are also experiencing increasing failures which have severe consequences on the system, including the loss of remote control and monitoring of the station, protection for MSs, and security systems. Both assets require long lead times to procure, design, and construct the replacement units regardless of whether the replacement is proactive or reactive. As such, they are prioritized based on the reliability risks they present to the system and large customers.
Direct Current ("DC") Battery Systems	Toronto Hydro replaces and maintains DC battery systems to ensure they can supply power to the station for eight hours (as mandated by the Transmission System Code). Replacement of the assets is prioritised based on functional obsolescence, age, and condition of the asset.

Table 6: Summary of Metering Asset Replacement Practices

Asset	Asset Replacement Practices
Meters	Toronto Hydro replaces meters proactively at or beyond the end of their useful life to manage risk of failure and customer billing interruptions. Meters are replaced reactively if they fail to read or communicate or suffer complete failure.

D3.2 Asset Lifecycle Risk Management Policies and Practices

Customer-focused outcome measures such as system reliability, safety incidents, connections efficiency, and oil spills are lagging indicators of system performance. These measures are essential to understanding the actual experience of customers, stakeholders, employees, and the general public in relation to the distribution system. However, certain lagging measures, by their nature, can be difficult to directly influence through actions taken in the near-term. This is especially true for measures that are influenced by asset failure. Toronto Hydro manages hundreds of thousands of distribution assets that are typically in service for decades. These asset can fail in a variety of ways at any point in their lifespan, and it is impossible to know with precision exactly when failure will occur. Therefore, in the daily effort to direct expenditures toward cost-effective interventions that will drive performance outcomes, Toronto Hydro must rely on risk – a leading indicator of performance – to make informed investment decisions.

As a large urban utility with a highly utilized system and a significant asset renewal need, risk assessment is essential to ensuring that system reliability and other outcomes can be maintained with a constrained expenditure plan.

This section outlines Toronto Hydro’s lifecycle risk management methods and practices for its distribution assets, detailing the utility’s risk assessment frameworks, including key considerations in risk evaluation, and typical risk mitigation approaches. Capacity related risk is discussed separately in Section D3.3.

D3.2.1 Overview of Risk Assessment Methods

Toronto Hydro’s risk assessment framework consists of the following key elements:

- Probability of Failure;
- Consequence of Failure; and
- Risk Analysis.

Details of each key element follows.

D3.2.1.1 Probability of Failure

Probability (i.e. likelihood) of failure is an important consideration in determining whether asset intervention is necessary. This section focuses upon two key forms of analytics that are utilized to enable Probability of Failure evaluation: (i) Asset Condition Assessment ("ACA"); and (ii) predictive failure modelling.

1. Asset Condition Assessment (ACA)

As explained in Section D1 and in Appendix C to Section D, Toronto Hydro employs an ACA methodology to monitor the condition of various key asset classes within its system and produce a health index ("HI") score to support project planning. The ACA allows Toronto Hydro to use data collected data through inspections to produce a numerical representation of an asset's condition, taking into account key factors that affect its operation, degradation, and lifecycle. Toronto Hydro uses ACA to support tactical and strategic investment planning decisions. Planners use inspection data and individual HI scores – in combination with other information and professional judgement – to prioritize assets for tactical intervention in the short- to medium-term. This includes identifying priority deficiencies that require reactive or corrective action, and prioritizing assets for planned renewal projects in a given budget period. At a strategic level, Toronto Hydro uses ACA results to examine condition demographics and trends within major asset classes to support the development of longer-term investment plans within the annual Investment Planning & Portfolio Reporting ("IPPR") Process.

As part of the efforts to continually improve its asset management and decision-making framework, Toronto Hydro worked with EA Technology to develop new asset health models based upon the Common Network Asset Indices Methodology ("CNAIM"). CNAIM is the approach used by distribution network operators in the United Kingdom to report asset health as part of their regulatory reporting requirement. Toronto Hydro has used the outputs from this CNAIM-based model to support an advanced condition-based approach for planning and evaluating strategic capital investments. Toronto Hydro has provided additional details on the new ACA methodology in Appendix C to Section D of the DSP.

The approach used to develop the HI for each asset is illustrated in Figure 3.

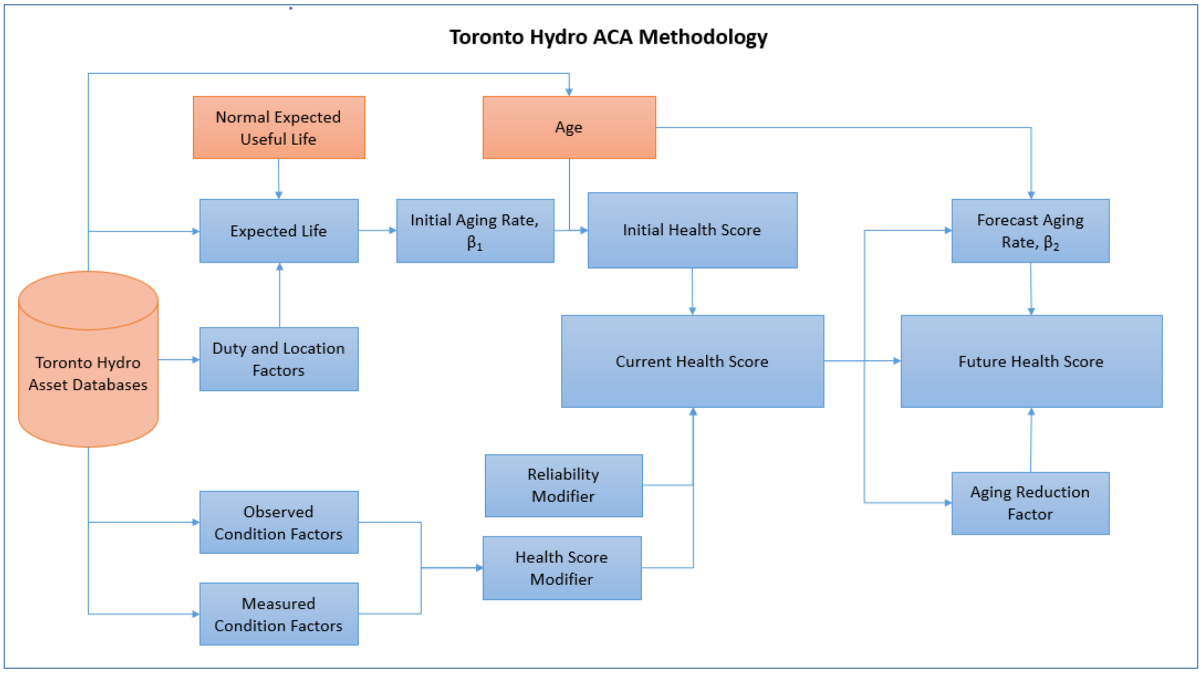


Figure 3: Asset Condition Assessment Process as Part of ACA

ACA results for a particular asset class are grouped into five HI bands that represent key stages of an asset's lifecycle, ranging from new or like new condition to the stage where asset degradation is significant enough to warrant urgent attention. Toronto Hydro uses asset HI demographics during the scope development phase of IPPR, as outlined in Section D1. It enables planners to assess the relative probability of failure of their assets in the short and mid-term timeframe based on the HI band. The bands are defined as per Table 7 below.

Table 7: Health Index bands and definitions

Band	Lower Limit of Health Score	Upper Limit of Health Score	Definition
HI1	≥ 0.5	< 4	New or good condition
HI2	≥ 4	< 5.5	Minor deterioration; in serviceable condition
HI3	≥ 5.5	< 6.5	Moderate deterioration; requires assessment and monitoring
HI4	≥ 6.5	< 8	Material deterioration; consider intervention
HI5	≥ 8	≤ 10	End of serviceable life; intervention required

Examples of asset classes with HI scores are shown in Table 8 below.

Table 8: Assets Evaluated in the ACA Program

Switches	Breakers	Vaults	Transformers	Other
• Overhead Gang-Operated • SCADA-Mate • Air-Insulated Padmount • SF_6-Insulated Padmount • SF_6-Insulated Submersible • Air-Insulated Submersible	• 4 kV Oil Circuit (MS) • KSO Oil Circuit (TS) • SF6 Circuit (TS) • Vacuum Circuit (MS & TS) • Air Magnetic Circuit (MS & TS) • Airblast Circuit (MS & TS)	• ATS • CLD • CRD • Network • Submersible Switch • URD	• Station Power • Network • Submersible • Vault • Padmount	• Wood Poles • Network Protectors • Cable Chambers

The ACA output is essential in two respects. First, the ACA produces a relative outlook of the population's condition for each individual asset class within the program. Second, the ACA program highlights trends in the condition of asset classes. These trends can highlight issues that are specific to particular asset classes or subtypes such as manufacturing defects, or design practices. For system planners, these insights along with the health band of an asset provide an indication of the probability of failure for an asset. Being aware of these issues and trends allows Toronto Hydro to balance capital investments against continuing maintenance. More generally, the ability to compare current and future health index results for an asset class can support decision-making when developing expenditure plan envelopes for longer-term investment programs. In its 2020-2024 DSP, Toronto Hydro has used this information to compare proposed investment levels against current and projected volumes of assets in the two worst health bands ("HI4") and ("HI5"). For more information, refer to Section E2.

For more information on Toronto Hydro's ACA approach, refer to Appendix C to Section D.

2. Predictive Failure Modelling

Predictive failure modelling represents the other essential component of the Probability of Failure analysis. It involves the derivation of hazard rate functions for each asset class – also referred to as the assets' probability of failure. In this case, an asset's age is used as an input into the hazard rate calculation in order to produce the conditional probability of an asset failing based on the remaining population that has survived up until that time. The results from these failure curves provide insights into the expected failure rates of assets, which is critical information for determining the investments required to manage assets over the medium term.

Toronto Hydro's hazard rate distribution functions were each calibrated to a useful life value. Toronto Hydro's useful life values are also used separately as part of the Assets Past Useful Life ("APUL") calculation, in order to assess the demographics of assets, especially those approaching or past their useful life. Toronto Hydro utilizes this information to ascertain the upcoming "asset walls" and investment requirements that will emerge over a long-term period, and better equip its planners to make informed investment decisions and develop effective plans based on the needs of the system.

The aggregate information extracted from predictive failure modelling combined with the APUL calculation can be used as an input in determining the levels of expenditures required for managing each asset type. The predictive failure modelling procedure is also used as part of the economic risk-based analysis and reliability projection procedures, which are further discussed in Section D3.2.1.3.

3. Historical Reliability Analysis

The last component of Toronto Hydro's probability of failure analysis involves the analysis of historical reliability data from the Interruption Tracking Information System ("ITIS"), in order to identify assets with a high frequency of failure.

ITIS is used to store historical outage information which Toronto Hydro uses as a key tool in developing capital spending. By continuously analyzing the reliability performance of its circuits and substation assets, Toronto Hydro is able to identify areas experiencing reliability issues, which may be caused by asset deterioration or legacy design related issues. Toronto Hydro utilizes the following ten major cause codes to classify historical outages within ITIS:

- Adverse Environment;
- Adverse Weather;
- Defective Equipment;
- Foreign Interference;
- Human Element;
- Lightning;
- Loss of Supply;
- Scheduled Outages;

- Tree Contacts; and
- Unknown.

From a Probability of Failure perspective, the data contained within ITIS can be used to identify those asset classes and sub-classes, as well as parts of the system that experience a high frequency of failure. As an example, ITIS data has been utilized as part of Toronto Hydro's planning procedures to identify feeders containing the most problematic direct-buried underground cables.

D3.2.1.2 Consequences of Failure

When determining the risk of asset failure, there are two components considered; the probability (explained in Section D3.2.1.1) as well as the consequences and impacts of failure, which go into to the specific failure modes and effects associated with those failure modes. These consequences are generally broken down into key categories that generally align with Toronto Hydro's outcomes framework (i.e. customer service, reliability, environment, safety, and financial impacts).

1. Customer and Reliability

Derivation of the customer or reliability impacts is undertaken through a number of tools and approaches, including:

- Customer engagement and consultation activities;
- Key account customer program and responses to customer calls and complaints;
- Reliability analysis identifying long-duration impacts; and
- Application of customer interruption costs.

Table 9 provides additional information related to each of the aforementioned tools and approaches.

Table 9: Summary information related to Customer and Reliability Tools and Approaches

Tool or Approach	Summary
Customer engagement and consultation activities	Toronto Hydro executes a variety of customer engagement programs designed to establish interactions with customers and provide necessary details related to capital and maintenance plans, including the following: a) Town hall meetings in specific districts or parts of the city to communicate investment plans or proposed projects and execution strategies; b) Ward or neighbourhood outreach activities where city councillors are provided necessary information from Toronto Hydro in regards to major investments and issues being mitigated within their respective communities; and c) A customer-focused power quality program in which Toronto Hydro monitors and investigates power quality issues for customers.
Key account customer program	Toronto Hydro manages a key account customer program for large commercial and industrial customers to address specific concerns and issues. Additionally, any specific customer concerns or complaints captured through Toronto Hydro's call centre are directed to engineers, asset planners, and managers within the Engineering (and Asset Management) group to investigate and determine whether projects already exist to address the concerns or if new projects (and additional actions) are required.
Reliability analysis identifying long-duration impacts	As explained above in Section D3.2.1.1, Toronto Hydro utilizes its ITIS system to gather historical reliability data across the distribution system for the purposes of performing reliability-driven analyses. For example, ITIS is relied upon for insight into the number of customers affected by outage events in the system and the duration of each event. From a consequences of failure perspective, this information is used to identify typical outage duration impacts within the system, and to plan and prioritize projects as illustrated in programs such as Area Conversions (Exhibit 2B, Section E6.1) and Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2). Given Toronto Hydro's reliance on the functionality that ITIS provides, Toronto Hydro is investing in this functionality as part of its upgrade of the existing Outage Management System with a new Network Management System ("NMS"). Toronto Hydro expects that this investment will provide more robust data and enable greater insights. These upgrades are expected to be completed in the period 2018-2020.

Tool or Approach	Summary
Application of customer interruption costs	Toronto Hydro utilizes customer interruption costs ("CICs") which represent a measure of monetary losses for customers due to an interruption of electric service. CIC values are calculated in two parts: the Event cost and the Duration cost. The Event cost represents the impact to customers due to the occurrence of the outage whereas the Duration cost represents the costs incurred as the length of the outage increases. Toronto Hydro currently adopts $30 per kVA (peak load) as the Event cost to represent the CIC value due to the initial period of the outage, and $15 per kVA (peak load) per hour to represent the CIC value due to the increasing duration of the outage. Toronto Hydro continues to enhance these values by directly surveying customers to understand their valuation of interruption costs. These CICs are used as input within the economic risk-based analysis as described in Section D3.2.1.3. As part of this analysis, the CICs are paired with customer impact information, including the associated customer load that will experience an interruption should the evaluated asset fail. This customer impact information includes the identification of the upstream protective device that will contain the fault, as well as the customer loading impacts, which are derived from the peak load of the downstream transformers. Collectively, this information is used to quantify the full customer impact of failure for each evaluated asset within the system.

2. Environment

Toronto Hydro takes all reasonable actions to reduce the risk of asset failures resulting in adverse effects to the environment as well as safety incidents to its employees, customers and the public. In the case of equipment failure, environmental impact, and potential non-compliance or breach of regulatory obligations may result. Toronto Hydro's major environmental concerns include: (i) oil leaks of all types; (ii) reducing greenhouse gas emissions; and (iii) the use of substances like asbestos, lead, and PCBs in its equipment.

Through planned asset inspections, oil deficiencies in the system are identified and necessary corrective action is taken. Toronto Hydro is continuously striving to mitigate environmental risks such as the risk of oil spills, while simultaneously ensuring compliance with federal, provincial, and municipal regulations pertaining to the release of oil into the environment. Similarly, through inspection and renewal programs, assets containing lead, asbestos, and PCBs are identified and proposed for replacement with standardized and less harmful equipment.

3. Safety

Mitigating safety risks to Toronto Hydro employees and its customers is the highest priority objective of Toronto Hydro's AM process. As highlighted in Section E2.3, customers consider the safety of the system to be a default priority for the utility. Toronto Hydro continues to strive for zero public and employee safety incidents each year.

Nearly all of the utility's asset renewal, service, and maintenance activities are driven in part (and sometime entirely) by safety considerations. For example, Toronto Hydro's programs to reduce and eliminate obsolete legacy equipment and configurations are driven in large part by known safety risks and related operational restrictions. Examples of these activities include:

- Eliminating safety risks related to Electrical Utility Safety Rules ("EUSR") compliance issues associated with legacy box construction configurations; and
- Reducing public and employee exposure to safety risks as a result of outages in rear lot configurations.

Toronto Hydro's Environmental, Health and Safety ("EHS") and Standards functions, funded by the Human Resources and Safety program (Exhibit 4A, Tab 2, Schedule 15) and the Asset and Program Management program (Exhibit 4A, Tab 2, Schedule 9), have important roles in maintaining safe work practices, implementing engineering controls, and adhering to requirements related to environmental protection and occupational health and safety. In the event of an incident relating to asset failure(s) where there is an environmental or safety risk, staff responsible for the aforementioned functions (i.e. EHS and Standards) will investigate to determine the defect in the equipment. EHS bulletins will be released for immediate notification of potential workplace hazards, accidents, injuries, near misses, environmental issues, and important information regarding accident prevention. If applicable, a new standard for a replacement product will be developed.

If the defective equipment poses a significant risk to the system, a capital or maintenance program would be proposed to replace the asset with a new standardized equipment. This was the case in the 2015-2019 CIR Programs of SCADA-Mate R1 Switch Renewal, Handwell Upgrades, and Polymer SMD-20 Switch Renewal. Within this application the Contact Voltage Scanning Segment under Preventative and Predictive Underground Line Maintenance (Exhibit 4A, Tab 2, Schedule 2) addresses the scanning of the distribution system for contact voltage to reduce risk of public exposure to contact voltage from energized surfaces and structures.

4. Public Policy

In addition to addressing customer reliability, environmental, and safety concerns, Toronto Hydro must remain compliant with public policies and regulations. Through its renewal programs and consistent with the Ontario Long-Term Energy Plan, Toronto Hydro is investing in asset designs that are more resilient to changes in weather and climate such as the use of submersible network protectors to tolerate flooding. Additionally, implementing demand response programs reduces the strain on Toronto Hydro distribution assets and as such reduces failure risk.

Certain circumstances or asset failures carry with them the risk of putting Toronto Hydro in violation of public policies. Some relevant public policies include:

- Managing asbestos as per the *Ontario Occupational Health and Safety Act* as well as the *Canadian Environmental Protection Act* to eliminate and phase out asbestos;
- Reducing the risk of PCB leakage into the environment and eliminating all PCB containing equipment greater than 50 ppm to comply with PCB Regulations as defined in the *Canadian Environmental Protection Act*, SOR/2008-273 and in the City of Toronto *Municipal Code,* Chapter 681 – Sewers; and
- Ensuring compliance with *Ontario Regulation* 22/4 and safety performance as measured through the Serious Electrical Incidents Index.

5. Financial

Some of the consequences of asset failure discussed above can also have significant financial impacts for Toronto Hydro. Asset failure can cause outages disrupting the normal operations of businesses (leading to monetary losses as represented by CICs discussed in Table 9 above), damage the surrounding area (e.g. through oil spills), and create safety risks. These can increase the risk of Toronto Hydro incurring additional costs for environmental remediation, fines, and legal costs in the form of claims and resulting litigation. The potential financial impacts of failure differ depending on the nature of the failure and from asset to asset because assets operate under varying conditions and loadings.

D3.2.1.3 Risk Analysis

The probability and consequence inputs, as identified in Sections D3.2.1.1 and D3.2.1.2 respectively, are used either individually, or in combination as part of analyses prior to arriving at risk-based decisions related to long-term and short-term asset management plans and investments. The risk of failure may be determined by using a combination of qualitative and quantitative methods. Various risk-based tools are utilized to provide multi-faceted perspectives that support and ultimately justify investment decisions.

The following subsections provide insight into the various risk-based decision-making tools that are used at Toronto Hydro.

1. Economic Risk-Based Analysis

Toronto Hydro's economic risk-based analysis methodology supports the utility's engineering assessment of system intervention and design alternatives. This methodology calculates an economic end-of-life for each asset by balancing the increasing risk of asset failure against the necessary investment costs that must be incurred in order to mitigate these risks. Toronto Hydro leverages the Feeder Investment Model ("FIM") tool to produce these calculations. Key input data includes results from Predictive Failure Modelling described in Section D3.2.1.1, and quantified reliability impacts to customers (i.e. customer interruption costs).

The FIM also stores the financial costs to the utility for replacing the evaluated assets should they fail within the system, along with the typical failure modes associated with the asset in question. From these parameters, an annualized risk cost and an annualized capital cost can be derived for the new asset to be installed, and a life-cycle cost established based upon a sum total of these two components. The lowest life-cycle cost of the new asset – or the Equivalent Annual Cost ("EAC") – may be compared to the risk cost of the existing asset to identify the economic end-of-life for the existing asset. This is further illustrated in Figure 2.

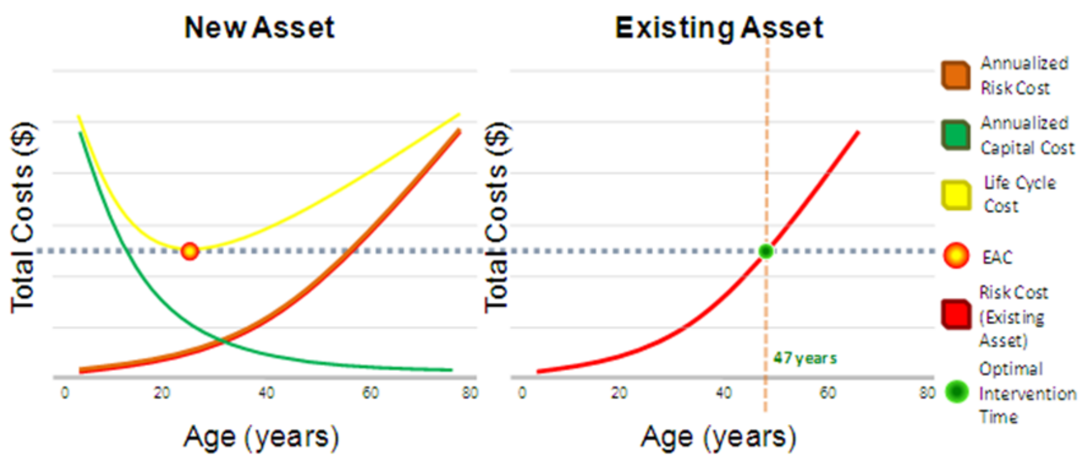


Figure 4: Typical Example of Establishing the Optimal Intervention Time for an Existing Asset

Figure 4 illustrates that past the point of the lowest life-cycle cost (i.e. EAC), it becomes more expensive to continue to operate the existing asset, when taking into consideration both financial impacts to the utility as well as socioeconomic impacts (including those relating to customer and reliability, safety, and environmental impacts). The economic end-of-life results from this analysis are mainly used to evaluate the net benefits of asset intervention alternatives.

2. Reliability Projections

In order to conceptualize the impact of investment programs, Toronto Hydro performs an analysis of historical system reliability and produces a reliability projection ("RP"). The RP provides a risk-based view utilizing the major reliability indices (e.g. SAIFI, SAIDI) and enables informed decision making for capital investments. The RP is based upon:

a) asset demographics data;
b) historical reliability performance; and
c) planned program investments.

The system historical reliability category is broken into individual cause codes and in some cases (e.g. defective equipment) down to the asset level.

As part of the RP process, a reactive replacement scenario is produced, to estimate the performance of the current system without proactive intervention. The scenario depicts what is expected if assets remain in service and naturally reach end-of-life. Asset failures increase as they are operated beyond useful life, contributing to worsening reliability. This provides a reliability centric risk view for Toronto Hydro.

In addition to the reactive replacement approach, Toronto Hydro produces program scenarios to project the reliability impact of the investment programs on the system. This is determined by reviewing each planned program for reliability benefits, improved operational flexibility, and influences on asset demographics. The program benefits are applied to the individual outage cause codes (listed above in section D3.2.1.1) based on their level of impact on reliability. The results are then aggregated to the system level to obtain the final system-wide reliability projections. RP analysis and results used in the development of the capital expenditure plan are discussed in Section E2.2.2.3.

In general, this conceptual analysis is used by Toronto Hydro to evaluate reliability impact of the proposed capital expenditure plan. It should be noted that this projection does not consider major event days, nor the lasting impacts that major weather events can have on asset performance in future years.

3. Worst Performing Feeder ("WPF")

Toronto Hydro assesses the overall performance of the system in order to improve service reliability for customers supplied by poorly performing feeders. The utility identifies feeders at risk of experiencing seven or more sustained interruptions ("FESI-7") each year (or over a 12-month rolling period). Once the feeder and the root cause of its failures have been identified, mitigation work on these feeders is conducted so that the risk of additional interruptions to customers can be mitigated. In addition to the FESI-7 metric, Toronto Hydro has introduced a FESI-6 metric that identifies at-risk feeders serving Large Commercial & Industrial class customers within the distribution system. Additional details related to these measures, which are in place to improve reliability and meet the needs of customers, may be found in Exhibit 2B, Section C.

The WPFs in the system are typically addressed through a combination of short-term intervention (both capital and maintenance) and complementary planned renewal work. As a result of investments to improve the reliability of these feeders, sustained improvements have been achieved as illustrated in Section C.

For more detail on the work proposed as part of WPF investments, refer to Exhibit 2B, Section E6.7.

4. Enterprise Risk Management

Toronto Hydro considers a broad range of risks that the corporation faces through the Enterprise Risk Management ("ERM") process. Toronto Hydro's ERM framework has been designed to manage risks at the corporate level, and considers the risks facing individual asset classes and risks relevant to investment programs.

Toronto Hydro continuously works to identify and manage corporate risks that emerge from the asset base, and create new programs to manage these risks when prudent to do so. For example, various risks have been analyzed and managed using the ERM framework including risks posed by direct-buried cables, porcelain insulators, cable chamber lids, and secondary cables. The ERM framework groups such risk under categories such as "asset integrity risk" or "public safety risk". The ERM framework and the analytical results derived from the ERM process serve as another input into Toronto Hydro's overall risk assessment and management procedure. This input is available and updated regularly for monthly and annual tracking of risk mitigation measures while providing visibility into broader corporate risks.

5. Defective Equipment Tracking and Priority Deficiencies

When defective equipment is found, either through a planned inspection or following emergency response, Toronto Hydro applies a risk framework to help prioritize repairs and corrective actions. In addition, the framework, which is referred to as Defective Equipment Tracking System ("DETS"), is useful for assessing risk trends related to both particular asset classes and the system overall.

The DETS framework utilizes information about defective equipment to assign a score, which reflects the following criteria:

- **Impact**: number of customers impacted by the defective equipment incident;
- **Contingency**: what is the criticality of the equipment and are there any contingency options; and
- **Restoration**: the estimated restoration time to the customers.

Each criteria is assigned individual scores and when combined for a particular piece of equipment, could reach a maximum of 1,000. Once scored, a piece of defective equipment is then prioritized for corrective work as part of Toronto Hydro deficiency prioritization process that is used for all deficiencies identified during the course of utility operations (and not just defective equipment deficiencies). That process has three categories of priorities:

- **P1**, requiring a resolution within 15 days;
- **P2**, requiring a resolution within 60 days; and
- **P3**, requiring a resolution within 180 days.

A P1 is assigned to defective equipment that has a DETS score greater than 100 and a P2 is assigned to defective equipment that has a score less than 100. Analysis of the DETS scores and the volumes of priority deficiencies provides Toronto Hydro with another layer of risk modelling and inputs for risk management.

For additional details related to deficiencies, defective equipment, and prioritized reactive and corrective actions, please see the Reactive and Corrective Capital (Exhibit 2B, Section E6.7), Corrective Maintenance (Exhibit 4A, Tab 2, Schedule 4), and Emergency Response (Exhibit 4A, Tab 2, Schedule 5) programs.

6. Legacy Assets

Toronto Hydro's risk assessment frameworks include inventories of legacy assets and configurations that have been identified based on various factors (e.g. their likelihood of failure and resulting impact on system reliability, safety, or the environment). These assets and configurations are also typically functionally obsolete with limited or no support from manufacturers or third party service providers. Toronto Hydro monitors these legacy assets to manage and minimize their associated risks to customers, employees, and the public. The utility evaluates legacy asset risk and performance over time, adjusting investment plans over the short-, medium- and long-term to ensure the risks are being addressed at an appropriate and feasible pace. The reduction or elimination of these assets and the associated risks was a major contributing factor when developing the investment plans outlined in Section E of the DSP. For more information on Toronto Hydro's legacy assets, please refer to Section D2.

D3.2.2 Overview of Risk Mitigation Methods

Through its capital and maintenance investment plans, Toronto Hydro mitigates both the quantitative and qualitative risks identified above. Toronto Hydro manages risks by prudently investing in its assets while deriving value for customers. As such, the risk-based models and approaches described above are key inputs into the decision-making process for investment planning. Assets that pose a risk to the system are identified based on their contribution to the various risk factors discussed above as part of the IPPR process and grouped into investments categories of System Renewal or System Service.

D3.2.2.1 System Renewal Investments

As part of Toronto Hydro's risk mitigation efforts, System Renewal investments form a significant portion of the utility's capital investments. In addition to investments that help reduce the probability of failure based on age and condition, this investment category also contains programs aimed at addressing the other risk areas identified in Section D3.2.1.2 and D3.2.1.3 above. Programs such as Area Conversions (Exhibit 2B, Section E6.1) are aimed at eliminating legacy designs along with their reliability and safety consequences. In addition, renewal programs inherently target assets that pose environmental risks, such as oil leaks, especially for equipment containing PCBs. The System Renewal category also includes more specialized programs that address areas with high historical failures or failed assets, through programs such as the Reactive and Corrective Capital program (Exhibit 2B, Section 6.7).

D3.2.2.2 System Service Investments (Enhancements)

In addition to mitigating risk through the renewal of assets, Toronto Hydro invests in programs that allow for other cost-effective forms of risk mitigation. For example, in the network system, Toronto Hydro is investing in monitoring capability for vaults through the Network Monitoring and Control program. This program allows Toronto Hydro to proactively identify key issues affecting the network system such as vault flooding in order to intervene prior to potentially catastrophic asset failure. Installation of network monitoring and control systems or SCADA-Mate switches (on overhead lines) allows Toronto Hydro to address reliability related risks (in particular, outage duration risks), in a manner that compliments renewal activities in delivering the utility's overall reliability objectives.

D3.2.2.3 Maintenance and Refurbishment Activities

Toronto Hydro uses maintenance programs, as detailed in Exhibit 4A, to both identify and mitigate risks in the system. Inspections are key in providing data inputs for risk analyses, including assessment of asset condition and identifying priority deficiencies that require intervention. This data provides Toronto Hydro with information on assets that is critical to decision making, such as the presence of oil leaks or other forms of equipment deterioration. In addition, maintenance programs can help maximize the life of assets, thereby managing the overall need for capital intervention. For example, treatment of wood poles helps protect against infestation and rot, reducing the probability of failure.

D3.2.2.4 Other Investments

Toronto Hydro must also invest to ensure it manages risks in terms of meeting the needs of its customers and stakeholders. For example, it must meet the expectations of regulatory bodies and governments with respect to policies. This includes proactive metering investments that ensure Toronto Hydro remains in compliance with the requirements set by Measurement Canada. Investments are also required to ensure that capacity is available for connecting customers, which is further discussed in Section D3.3.

D3.3 Asset Utilization Policies and Practices

This section highlights Toronto Hydro's policies and practices in regards to capacity planning and the connection of both load and generation customers. It details Toronto Hydro's process to assess capacity requirements, connections, and steps to mitigate risks.

D3.3.1 Capacity and Connections Capability Assessments

Toronto Hydro continues to monitor capacity related risks within its system from both a short- and long-term view point. This includes working with third parties such as the Transmitter (i.e. Hydro One Networks) and the IESO as required for planning purposes, for both load connections and generation connections.

D3.3.1.1 Distribution Capacity & Capability Assessments

1. **Load Forecasting**

Toronto Hydro uses a load forecasting process to identify spare capacity at substations or points of constraint within the system. This allows Toronto Hydro to maintain awareness of bus capacity as new connections are made and natural load growth (or reductions) occur. The load forecast provides a short- to mid-term view of the station bus capacity so that appropriate plans can be made to accommodate varying growth rates within the system.

In order to complete a ten-year load forecast at the substation level, as shown in Figure 5, Toronto Hydro identifies the annual peak loads (both summer and winter peaks) for each bus at its substations. These peak loads are then normalized based on historical temperatures at which these peaks occur. Any information available for customer connections at the time of analysis is included based on the required connection time and the load requested by the customer. Only 70 percent of the requested load is applied, as past experience indicates that the load requested is often overstated in the application phase. Next, historical growth rates are calculated and used to forecast future load growth. If no discernable trend can be identified, then the growth rate used in Hydro One's long term forecast, as presented in the Metro Toronto Regional Infrastructure Plan (Exhibit 2B, Section B, Appendix C), would be used instead. Finally, any planned work which will directly or indirectly transfer load from one bus to another, such as load transfers or voltage conversions, is incorporated into the forecast.

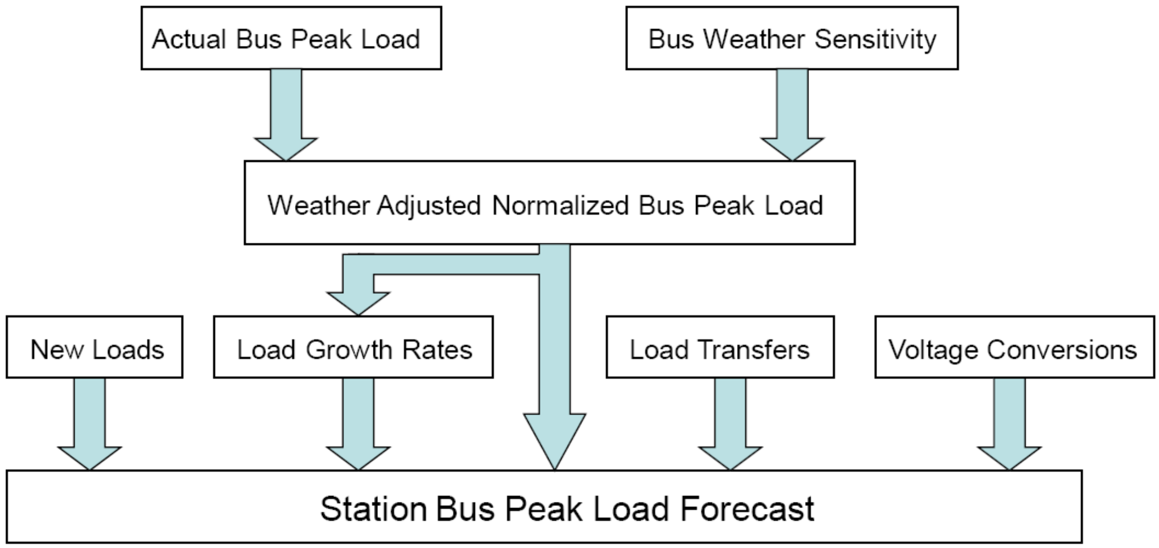


Figure 5: Process to Forecast Load at Substations

2. Connection Capability

In order to connect new customers, both capacity and spare feeder positions are needed. As existing feeders reach their capacity, new feeders must be pulled from a station into the distribution system to connect new customers. Although a station may have the capacity to supply this demand, if there are no feeder positions to connect new feeders to the station, then the station would be unable to support new connections. To this end, Toronto Hydro also monitors the number of spare feeder positions at its stations. When new feeders are needed and no spare feeder positions are available, Toronto Hydro engages in capital work under the Load Demand program to transfer feeder loads and free up feeder positions so that new customer connections can be made.

D3.3.1.2 Generation Capacity & Capability Assessment

Increased demand for power from consumers and the interconnection of distributed generation ("DG") has placed limitations on certain areas of the system. Toronto Hydro supports connecting DG to the distribution system in alignment with the Distribution System Code and in coordination with Hydro One Networks and the IESO. Toronto Hydro has identified a number of constraints within its system that impact DG connections and interconnection-related decisions, including the following:

1) limited breaker and station equipment capacity due to short circuit capacity constraints;

2) reverse power flow limitations based on transformer thermal capacity and minimum load requirements;
3) anti-islanding conditions for DG; and
4) system thermal limits and load transfer capability.

Fault assessments conducted by Toronto Hydro, and a prior DG capacity study conducted by Navigant in April 2011, have shown short circuit limits on station equipment to be the primary constraint.[5]

To determine the short circuit capacity at stations and other locations on the distribution system, sophisticated fault and power flow simulation models are employed. These models predict how much fault current will flow to a specific location from generators located throughout the distribution system. The presence of DG on distribution feeders can contribute to fault current that can cause station equipment, such as circuit breakers, to exceed short circuit capacity limits. Studies are performed for each new DG application enabling Toronto Hydro to continually evaluate the available existing short circuit capacity of the system.

D3.3.2 Capacity Risk Mitigation Methods

Based on the risk assessments above, Toronto Hydro invests in a number of programs to mitigate the risk of capacity shortfalls or the inability to connect new customers. These methods include expansion to increase capacity, enhancements to better utilize existing equipment, and load transfers as detailed below.

D3.3.2.1 Expansion Investments

Expansion investments provide one approach to manage the risk of capacity shortfalls within the system. By increasing capacity at substations, Toronto Hydro is able to address the need in localized areas of the system that experience load growth. Investments for expansion are primarily funded through the Stations Expansion program, as detailed in Exhibit 2B, Section E7.4. Expansion investments often require involvement from the transmitter, and Toronto Hydro may need to provide capital contributions for upgrades to transmission equipment at substations to enable an increase in capacity. Expansion may also be embedded as part of renewal activities for power transformers and switchgear units if deemed necessary, either to increase capacity or to increase

[5] See EB-2011-0144 Exhibit G1 Tab 1 Schedule 2 THESL 2012 GEA Plan – Appendix D: DG Interconnection Capacity Study

the number of feeder positions available at a substation to provide new feeders to connect customers.

D3.3.2.2 Load Transfers

Prior to investing in expansion projects, Toronto Hydro assesses the feasibility to alleviate capacity shortfalls by transferring load to adjacent feeders, buses, or substations. If feasible, transfers are typically more cost effective than expansion. This approach allows Toronto Hydro to ensure efficient utilization of its existing infrastructure prior to investments in expansion.

D3.3.2.3 Enhancement Investments

Toronto Hydro also considers investments that allows it to enhance the system in order to alleviate capacity shortfalls or connection limitations. To manage load restrictions, especially due to peaks, Toronto Hydro has worked extensively with its customers to implement a Local Demand Response program to manage peak demand effectively, as detailed in Exhibit 2B, Section E7.4. For generation connections, investments in monitoring and control equipment are made through capital programs (e.g. Generation Protection, Monitoring, and Control, as further explained in Exhibit 2B, Section E5.5) to actively manage DG sources to ensure safe connections. These investments allow Toronto Hydro to effectively manage capacity and connection limitations, without the need for extensive renewal activities, thereby deferring large capital investments.

D3.4 Program Planning Approach and Project Development

This section details the framework and process that Toronto Hydro relies on to develop its capital and maintenance programs. It highlights the key components of the IPPR process that drives the development of investment programs for distribution assets, as shown in Figure 6.

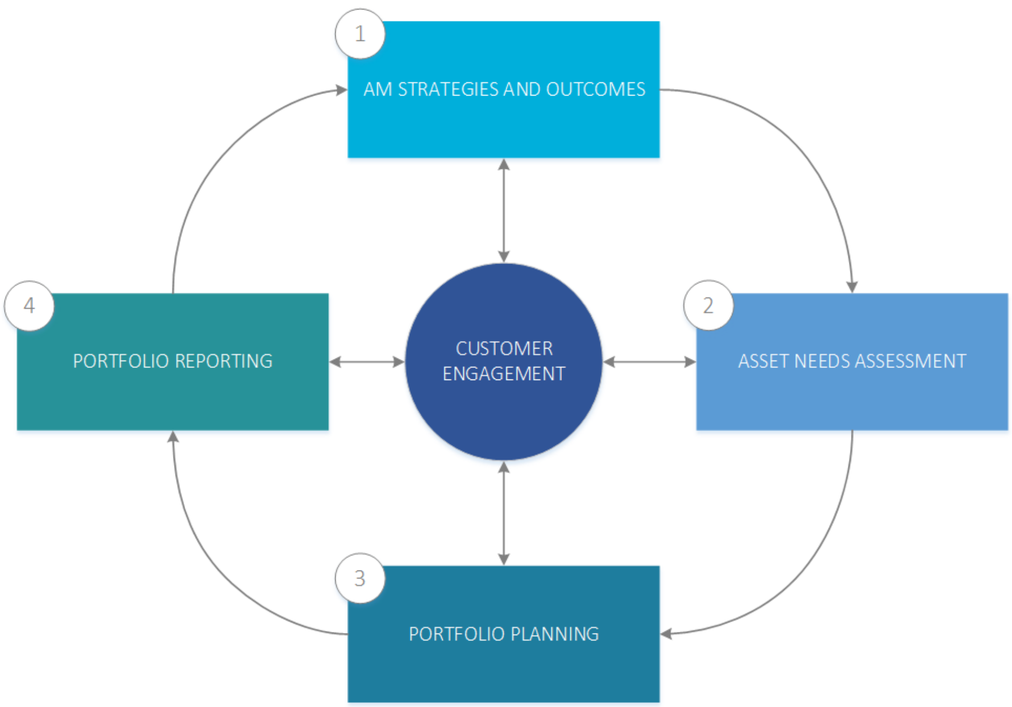


Figure 6: The IPPR Program Development Framework

The process can be divided into four key components:

1) **Asset Management Strategies and Outcomes:** The process begins by establishing the investment plan objectives and is informed by both the broader corporate strategy as well as customer engagement feedback.
2) **Asset Needs Assessment:** This part of the process establishes an understanding of the current state of assets based on asset demographics and ACA results. This information provides the base data required for planners to analyze the risk that the asset poses to the system.
3) **Portfolio Planning:** Based on the information outputted from the first two steps and the various risks discussed above, Toronto Hydro analyzes assets to identify the required level

of spend to manage risk and in turn achieve the intended outcomes. Based on the driver of the work, investment programs are established as part of this step.

4) **Portfolio Reporting:** Once investment programs have been executed in the field through individual projects, the IPPR process includes a feedback loop where the project-specific execution status and project expenditures are reported to evaluate the projects proposed in upcoming years.

D3.4.1 Asset Management Strategies and Outcomes

As discussed in Section D1, Toronto Hydro's AM Process is guided by strategies and related outcome objectives that the utility sets in alignment with its corporate pillars and Customer Engagement results. Figure 4 in Section D1 provides a summary of the AM strategies and outcomes, and Section E2 provides an overview of how Toronto Hydro established its AM outcome objectives for the 2020-2024 DSP.

Toronto Hydro uses outcome measures in each outcome area to quantify the impact of investments towards each outcome. This framework is integral in enabling decision-making for asset management in both the long-term and short-term. Toronto Hydro's Custom Performance Measures for the 2020-2024 period are discussed in detail in Section C.

D3.4.2 Asset Needs Assessment

In order to create an optimized program, Toronto Hydro completes a needs assessment. In this regard, an important tool is the current state analysis ("CSA") which provides Toronto Hydro with an assessment of the major assets that are currently installed in the system.

Key parameters that are collected from and integrated into the CSA include:

- asset registry data (e.g. nomenclature, asset class/sub-class, installation type);
- asset quantity data;
- age and condition demographics data; and
- asset-class and system-wide replacement value based upon useful life criteria.

The CSA utilizes information from Toronto Hydro's various enterprise systems, including the Geographic Information System ("GIS") and Enterprise Resource Planning ("ERP") system to establish the core asset registry data and asset demographics. Through the development of the CSA, Toronto

Hydro can quickly establish key information on major assets including condition, age, useful life, and replacement value.

There are two key outputs from the CSA process:

- **Asset demographic data:** Provides a yearly break down for the number of asset units installed along with their respective costs. As a key input for a data driven long-term planning process, this data set ultimately allows Toronto Hydro to establish the percentage of assets past useful life.
- **Condition demographic data:** Indicates demographics from a HI perspective for each asset class and sub-class, helping to flag higher risk assets within the system from a condition perspective.

This process establishes foundational data that is used in the long-term and short-term planning processes for distribution assets. Figure 7 illustrates the inputs, elements, and outputs associated with the CSA.

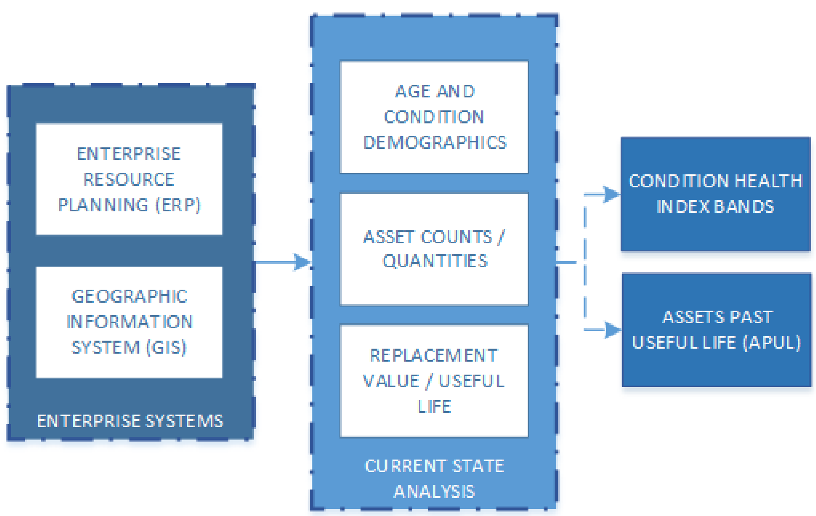


Figure 7: CSA Process

In addition to asset specific data, Toronto Hydro assesses emerging needs and challenges of the system by evaluating additional risk factors. For example, Toronto Hydro evaluates the available and forecasted capacity of the system to identify capacity related risks. As discussed in Section D1.2.1.2 as well as D3.3 above, this is done through load forecasting, load and generation connections forecasting, as well as the Regional Planning Process. These processes enable Toronto Hydro to identify spare capacity and anticipate areas of potential constraints as a result of developments and load growth or reductions in different areas of the City. The Regional Planning Process is an important input for distribution system planning (specifically, station plans), as a result of infrastructure planning on a regional basis to better predict system challenges.

Toronto Hydro accounts for emerging needs as they arise in the system. This could be as a result of asset specific information (legacy assets and configurations, safety and environmental concerns relating to a specific type of asset), climate and weather impacts, or available capacity to connect customers. The processes identified in this section are used to assist system planners with developing well informed plans that consider the various risks and challenges mentioned above in order to meet the needs of the system.

The results of the Asset Needs Assessment that formed the basis of Toronto Hydro's system investment plan for 2020-2024 is discussed in Section E2.2.

D3.4.3 Portfolio Planning

The Portfolio Planning process produces program-level expenditure plans in alignment with the utility's asset management objectives. As part of Portfolio Planning, asset-related data from the CSA is combined with system-wide information regarding known challenges facing the distribution system in order to assess asset and system needs. Toronto Hydro relies on the analyses and decision support tools (as discussed in Section D3.2 and Section D3.3) to identify assets or areas with high levels of risk requiring intervention. When identifying and proposing portfolios, the utility also accounts for customer feedback resulting from regular customer engagement activities. Customers' needs and preferences are a key input for determining the investments needed to meet customers' expectations on service.

During the Portfolio Planning process, Toronto Hydro develops investment requirements for managing system assets and challenges, based on the condition of assets, age of assets, risks of asset failure, legacy assets within the system, load growth, opportunities for modernization, etc. The analysis of assets from both a risk and outcomes perspective during the investment planning process ultimately drives the development (and management) of capital programs, which are detailed in Exhibit 2B, Sections E5 to E7 of the DSP.

The various risk analyses presented in Section D3.2 and Section D3.3 drive the overall investment required to manage the distribution system. Toronto Hydro assesses its entire asset base in light of the risks discussed above. Assets that are past their useful life or in HI4 ("material deterioration") or HI5 ("end of serviceable life") condition are identified, as defined earlier in Section D2.2. Information regarding historical failures is combined with asset level information to better understand not just the probability of failure but the cause of failure as well. The configuration of the system is also analyzed in these cases to see if inherent design limitations are contributing to increased risk for specific assets or types of configurations in the system. For example, the presence of legacy assets, such as box construction, can often result in safety or environmental consequences. The severity of the risk posed by these assets is considered when deciding whether to invest in replacing these assets proactively and also in determining the correct pace of replacement. Ultimately, similar types of interventions with the same driver are aggregated into capital programs. The expected probability of failure and localized reliability information also drives the requirement for Reactive and Corrective capital in order to address the level of failures observed.

In addition, Toronto Hydro must also consider work that must be accomplished as part of its mandate (e.g. pursuant to the Distribution System Code), and responsibility as a Local Distribution Company ("LDC"). These investments may be demand driven or initiated by a third party, and are categorized as System Access programs, such as Customer Connections or Externally Initiated Plant Relocations.

Program expenditures are then aggregated to create a total investment plan for any given year. The impact of the cumulative investment plan on outcomes is considered to ensure that investments are made in a prudent manner that manages the various risks discussed in this section while providing value for the customer.

Toronto Hydro considers, on an aggregate level, the impact of various investment levels on outcome measures, including (but not limited to) to SAIFI, SAIDI, FESI, system health, system capacity, and PCB contaminated oil spills. By forecasting the performance of key outcome measures over the long-term under proposed investment levels, Toronto Hydro is able to understand trade-offs in investing in different programs and at different investment levels. This initial investment requirement represents a bottom-up needs assessment by system planners for the optimal expenditure levels required.

Various investment strategies are reviewed and challenged internally before selecting a proposed approach. Once investment plans are reviewed, the information becomes a foundational input as part of other corporate business planning activities.

For more details on how these activities unfolded for the 2020-2024 Capital Expenditure Plan, see Section E2.

D3.4.4 Portfolio Reporting

The IPPR process also creates a feedback loop that provides information about program level completion and historical work executed in each program.

Information is reported on an individual project basis and includes the project's total spending and assets replaced or installed in any particular program. This data is broadly used within Toronto Hydro in assessing the status of capital programs as a result of the completed projects. This was first outlined in Section D1.2.1.3 under the discussions regarding the IPPR process. The aggregate of project-specific expenditures and asset units installed indicates how much of the capital investment program has been executed relative to the target for the program. Reporting is an important component in the process as it provides feedback on Toronto Hydro's ability to execute proposed investments as well as an opportunity to revisit and adjust plans for the upcoming years if needed.

D3.4.5 Project Development and Prioritization

As part of short-term planning activities, once capital investment programs are established, as explained in Section D3.4.3, assets and issues identified for each program are addressed as part of discrete capital projects. As explained within Section D1.2.2, the scope and project development process includes four phases: (i) identification of specific needs; (ii) assessment of options; (iii) high level scope creation; and (iv) refinement of scope and cost estimation.

During the first two phases, investment planners analyze discrete portions of the distribution system, such as a neighbourhood or street, in order to identify projects that align with the investment program criteria and drivers. Depending on the investment program driver and program type (i.e. core renewal, critical issues, or other necessary day-to-day operational investments), enterprise data is used to identify assets at a discrete level so that investment opportunities are identified, risk is managed, and outcome objectives are achieved. For example, with respect to a program driven by failure risk, enterprise systems and the analyses discussed in Section D3.2 can be utilized to identify the program-level prioritized assets that align with this driver.

In addition, ACA results can be used to identify those assets in HI4 and HI5, and the FIM can be used to evaluate the highest-value investments from a risk-mitigation perspective. ITIS can be used to cross-reference studied locations against historical reliability events and performance issues. Finally, enterprise systems including the GIS are used to further support the study process, by providing supplementary details such as age, asset type and sub-type information.

For safety or capacity constraint-driven programs, nameplate information or localized data (as per the load forecasting process, discussed in Section D3.3) may be used to identify specific investment needs.

When an investment need for a project within a particular investment program has been confirmed and verified, phase three of the Scope and Project Development is carried out. A project draft, also known as scope of work, is produced which confirms the assets to be replaced, and establishes the high-level design for the new assets to be installed. While some projects may involve assets replaced in-kind, other projects may result in the installation of new assets as per a new configuration. Examples include the conversion of overhead plant rear lot to underground plant in order to minimize non-asset-risk exposure, or the re-configuration of radial circuits to looped circuits and redistribution of load in order to reduce outage duration and impacts. Ultimately, the high-level forecasts produced via the long-term planning process will be further refined into an annual capital budget, as more rigorous project estimates are produced.

In tandem with producing the high-level design, Toronto Hydro documents the scope of work to be performed and produces a high-level cost estimate to execute the project. Efficiency savings can be realized by addressing the prioritized assets and issues along with adjacent assets that also require intervention as a single project, as opposed to replacing these assets individually on a reactive basis. A project study may also be divided into multiple project drafts where necessary to allow construction to be executed in manageable pieces that are minimally intrusive to both the general public as well as customers. As part of the project development process, Toronto Hydro also considers issues such as city road moratoriums, physical restrictions, or particular design related problems that may delay the project or require a redesign. The project draft then undergoes a quality control assessment, before proceeding into the project finalization stage through the planning supervisor.

Once approved, the project is further refined both in terms of the scope of work as well as the cost estimate. As part of this process, field visits are conducted to ensure accuracy of the data that is used, obtain additional information and measurements, and to understand other potential risks for construction. Permitting requirements are also dealt with at this stage. This process results in a more refined project draft and cost estimate.

Ultimately, a series of projects are produced for each investment program, which results in further refinement to the capital investment spending levels for the associated program. Once the projects are finalized, they will be scheduled for execution based upon the Project Management and Execution process outlined in D1.2.3. Each project is scheduled based upon relative priority, resource availability, and system constraints (e.g. contingency issues or summer switching restrictions). Factors that impact project scheduling and execution include:

- project scope and requirements, for example, asset delivery to locations and complexity of the site;
- external constraints such as coordination with external groups;
- permitting and moratoriums;
- coordination between other projects; and
- resource balancing.

As part of scheduling, investment planners and program managers meet to discuss the relative priority of the various projects to establish the capital work program for execution in a given year. As part of the execution process, the detailed project design and estimate are produced to finalize capital investment spending levels. To address any required change to the project cost, schedule, or scope of work, Toronto Hydro maintains a change management and governance process. This process provides visibility across all relevant stakeholders on major project changes, requiring approval so that the change is appropriately processed and documented for awareness regarding lessons learned for future projects.

D4 Facilities Asset Management Strategy

Toronto Hydro maintains a complex portfolio of facilities, including critical operational sites (e.g. stations and control centres), in support of the reliable and efficient operation of the utility's distribution system. The effective maintenance of these facilities is required in order to ensure adequate protection for electrical grid equipment, secure access for employees and security of designated areas, and appropriate work conditions to support employee productivity. In this regard, the utility strives to optimize the value and function of relevant assets through its Facilities Asset Management Strategy (the "Strategy"), which takes into account:

- Lifecycle management;
- Enhancement initiatives; and
- Regulatory compliance.

By implementing the Strategy, the utility's primary objective is to maintain the functionality and safety of its work centres and stations. This document describes the methodology and processes that comprise the Strategy and support Toronto Hydro's four strategic pillars: People, Financial, Operations, and Customer.

D4.1 Asset Management Process

Integrated asset management systems are integral to the operation of a large facilities program. Toronto Hydro's management of facility assets involves the continual analysis of asset condition on a planned cycle:

- **Daily:** through our robust Preventive Maintenance Program ("PMP") and Computerized Maintenance Management Software ("CMMS"). Various facilities metrics derived from CMMS are used to assess business cases for an assets upgrade/replacement/overhaul during the asset management process;
- **Monthly:** through our field inspections and safety audits; and
- **Annually:** through lifecycle reports, lessons learned from completed projects, and a defined maintenance manual.

When planning and executing projects, the utility makes strategic decisions that take into account complete project costs, operational costs, and business impact to Toronto Hydro. In addition, this decision-making process is based on Asset Condition Assessments that review:

- Actual field conditions;
- Industry standard useful life data (i.e. ASHRAE and RS Means Data);
- Analysis of lessons learned from past projects;
- Assessments and reports by independent experts (e.g. Asbestos Containing Materials Report, Designated Substances Report, Water Infiltration Report, Roof Condition Assessment, lighting assessment reports, Current Condition and Code Compliance of Vertical Service Ladders, and Security Systems Assessment); and
- Detailed Asset Registry maintained through CMMS.

D4.1.1 Condition Assessment Process

Asset condition is gathered and assessed through continual inspections, maintenance, and analysis. Relevant considerations (including observed condition, major findings, recommendations, and supporting photographs) are organized using UNIFORMAT II classifications in order to effectively compare and prioritize similar assets across Toronto Hydro's large facilities portfolio. A numeric value is assigned to each asset based on the following rubric:

Table 1: UNIFORMAT II Classifications

Rating	Condition	Recommendation
1, 2, 3	*Poor*	Budget within 1-5 years
4, 5, 6	*Fair*	Budget within 5-10 years
7, 8, 9	*Good*	No investment required

"Good" assets function satisfactorily or with only minor deficiencies that marginally affect performance. "Fair" assets have deficiencies that, if not corrected, could cause intermittent problems in the near term or complete failure or significant risk of failure in the long term. "Poor" assets have critical deficiencies which currently affect their function.

To appropriately reflect asset criticality as part of the assessment process, assets are also assigned a priority level based on the following rubric:

Table 2: Asset Priority Level Rubric

Rating	Priority
1	Critical System
2	Building Functionality
3	Run to Fail/Low Impact
4	Redundancy or Cost Effective Upgrade

A ”Critical System” would be one that poses an immediate safety hazard if required replacement or maintenance is not carried out (e.g. fire or life systems, water infiltration prevention/protection systems). ”Building Functionality” assets are those required for a building's efficient daily operation (e.g. doors, windows, electrical/mechanical systems, interior finishes, etc.). "Run to Fail/Low Impact" assets are those whose failure entail minimal risk and would not significantly affect Toronto Hydro's operations (e.g. Baseboard Heaters etc.).

D4.2 Asset Renewal Process

Toronto Hydro aims to minimize the impact of planned asset renewals. When assets are identified to be poor condition, a plan is implemented to repair, upgrade or replace the asset to restore or enhance its functionality in accordance with current standards (including regulatory and Toronto Hydro standards). The typical planning process includes a review of:

1) Lifecycle analysis;
2) CMMS analysis; and
3) Project requirements, such as accessibility, budget, environmental liabilities, inter-project dependencies, and coordination with other Toronto Hydro capital projects and planned maintenance.

D4.2.1 Asset Standardization

Toronto Hydro's facilities standards are based on legislated and regulatory requirements. Some examples include:

- Ontario Building Code;
- Ontario Fire Code; and
- *Accessibility for Ontarians with Disabilities Act*, *2005*.

The implementation of consistent standards across all work centres produces efficiencies by minimizing design, repair and inventory costs. Further cost savings can be achieved by maximizing the useful life of facility assets while balancing and optimizing the total lifetime cost of each asset.

D4.3 Investment Planning and Forecasting

Facilities Investment Planning and Forecasting ("IPF") is the process of developing a five-year program of prioritized investments (pursuant to the prioritization process discussed above), including a detailed plan for each year of the program. The IPF Process is divided into three streams:

- Lifecycle management;
- Enhancement initiatives; and
- Regulatory requirements.

The primary objective of facility asset lifecycle management is to minimize an asset's total lifecycle cost (i.e. by establishing the End of Economic Life) while ensuring reliable asset performance. As shown in the figure below, End of Economic Life is the point where total cost (including total ownership and maintenance costs) is at its lowest over an asset's lifecycle. Through the Strategy, the utility aims to ensure satisfactory service for Toronto Hydro employees and customers while achieving significant stable financial benefits. Capital projects are planned on a yearly cycle to adhere to strict budgetary restraints. When cost overruns occur (e.g. due to incremental needs), the root cause is identified and lessons learned are reflected in future project plans to enhance the accuracy of cost forecasting.

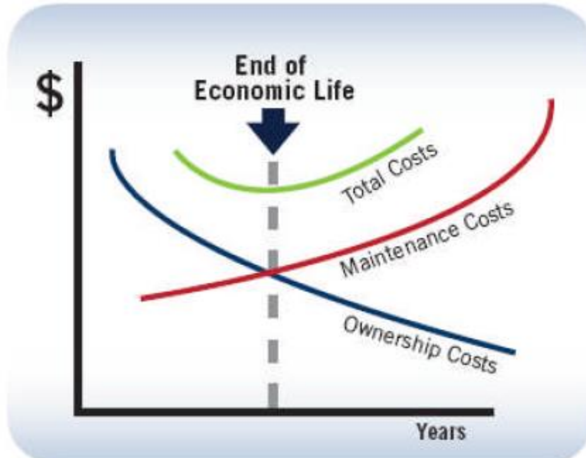


Figure 1: End of Economic Life Cost

D4.4 Summary

Through the Strategy, Toronto Hydro strives to maintain the operating functionality and safety of its facilities portfolio while optimizing asset lifecycle cost and related financial performance. Regular field condition assessments allow the utility to accurately capture the current state of an asset and evaluate asset maintenance costs and useful life so as to ascertain its impact in relation to the distribution business. The utility leverages robust planning and integrated CMMS to create metrics and reporting systems to ensure all assets are functioning as intended and minimize total lifecycle cost (including maintenance and ownership costs). Appropriate and timely corrective action is crucial to mitigating the impact of asset deficiencies or failures on Toronto Hydro's core business while supporting the minimization of total lifecycle costs. As discussed herein, the processes and methodologies that comprise the Strategy help ensure that Toronto Hydro makes prudent investments in its facilities portfolio in accordance with industry standard asset management practices and in support of Toronto Hydro's strategic pillars.

D5 Information Technology Asset Management Strategy

Informational technology ("IT") is a critical enabler for utility operations. Toronto Hydro relies on IT assets and systems to satisfy its obligations as a distributor, deliver its capital plans and operational programs, and pursue efficiencies and innovation.

The primary objective of Toronto Hydro's IT Asset Management Strategy is to derive sustainable value from its IT assets for the utility and customers. IT systems provide optimal value when they deliver expected levels of service in a sustainable manner and effectively mitigate risks (i.e. impact of failure, cyber security) at optimal costs. This schedule describes the IT asset management principles and IT investment planning methodology that enable Toronto Hydro to achieve this key objective.

IT asset management includes the purchase, operation, maintenance, renewal, replacement and disposition of IT data, hardware, and software assets. IT asset management is defined by IT standards, and includes:

- Requirements for data, hardware, and software assets (e.g. physical, performance, compatibility, security, etc.);
- IT architecture which establishes expected service levels (e.g. performance measurement, reliability requirements, incident/problem management for the assets); and
- Lifecycle management schedules for each type of asset.

IT Investment Planning is the process of making the best possible decisions regarding the scope and sequencing of asset management initiatives, including sustainment and enhancements. This process is based on well-defined IT standards and up-to-date information about the utility's IT assets.

Toronto Hydro's IT Investment Planning process is divided into two streams: (i) sustainment of existing systems; and (ii) enhancement initiatives. The process leads to the development of a five-year program of prioritized investments, including a detailed plan for the first year.

D5.1 IT Asset Management

Toronto Hydro developed IT standards to streamline and optimize IT asset life cycle, define system architecture and to gain operational efficiencies through the standardization of IT assets and components. IT standards are based on information provided by equipment producers (e.g. statistics on mean time to failure), internal historical data regarding asset failures, and industry best practices. Toronto Hydro reviews its IT standards regularly to ensure that they remain relevant for the utility and in alignment with the aforementioned considerations.

As described in more detail below, Toronto Hydro has adopted IT standards and architecture for data, hardware, and software assets. Having aligned hardware and software standards enables the implementation of an internal cloud platform – a collection of hardware resources which are required to complete desired computing operations that exceed the requirements of a single hardware machine. The implementation of an internal cloud platform provides the following benefits:

- Better management of IT assets, incidents, problems, changes, configurations, security, capacity, and availability of IT assets;
- Enhanced reliability of IT systems;
- Streamlined procurement processes and reduced operating costs;
- Operational efficiencies;
- Simplified monitoring of IT assets; and
- Enhanced security.

D5.1.1 IT Hardware Standards

IT hardware standards define the management of the physical IT components from acquisition through disposal. Common IT hardware asset management practices include need identification, procurement management, life cycle management, redeployment, and disposal management. These practices are applied to the following categories of hardware assets (see Figure 1):

1) **Core backend infrastructure assets**, which are responsible for the computation, storage and communication necessary to support IT systems; and
2) **Endpoint assets**, which allow end-users to execute, process, complete and review business tasks and operation.

Core Backend Infrastructure Assets

- **Computing**: servers and security appliances;
- **Storage**: disk arrays and flash arrays; and
- **Communication**: network and telephony assets.

Endpoint Assets

- **Computing:** desktops, laptops and tablets;
- **Printing**: printers and plotters; and
- **Communication:** desk phones, mobile phones.

Figure 1: IT Hardware Asset Categories

IT hardware standards and architecture specify which types of hardware assets Toronto Hydro requires to ensure a highly reliable, scalable and manageable platform for business applications, and document the capacity and lifecycle of these different assets.

IT hardware must be periodically refreshed to guarantee expected service levels of the systems and minimize the risk and impact of failure to the business. Through its IT hardware standards, Toronto Hydro seeks to define the optimal timing of asset replacement such that hardware assets are operated with the lowest acceptable failure rate at optimal costs. As illustrated in Figure 2 below, the lifecycle of IT assets generally follows a "bath tub curve" that breaks out into three distinct regions:

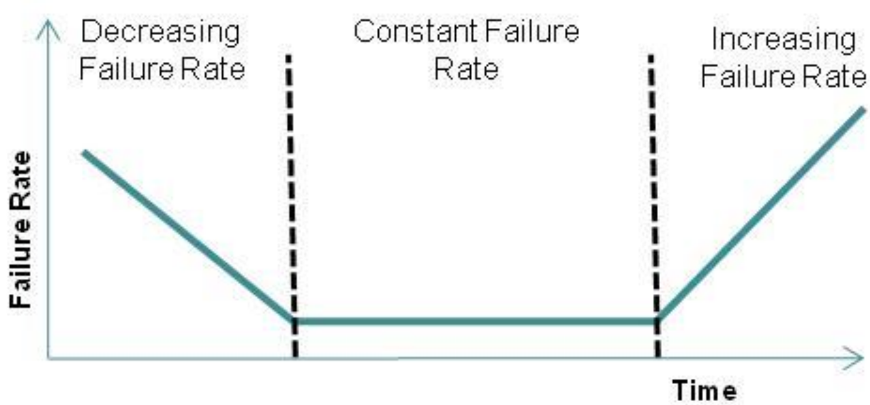


Figure 2: IT Hardware Asset Lifecycle Failure Rate over Time

- **Decreasing Failure Rate:** This is the region of the curve associated with a reduced failure rate over time. This is typical of new IT hardware, where once upfront implementation issues are addressed, failure rates tend to drop.

- **Constant Failure Rate:** As failure rate decreases to a certain point, it begins to stabilize and remain almost constant. The cost of ownership in this area of the bathtub curve is steady and considered financially optimal.
- **Increasing Failure Rate**: As the IT hardware ages beyond useful life, its failure rate starts to increase again due to the general operational wear and tear of the asset as well as vendor focus on development of new products (i.e. a lack of investment in and support for now obsolete products). As a result, system failures and associated maintenance costs start to rise steeply in this portion of the bathtub curve.

Based on the criticality of the infrastructure, industry best practice, and vendor specifications, IT hardware standards define the optimal time of refresh before reaching the "Increasing Failure Rate" portion of the lifecycle. This approach minimizes the risk of interruption to the core processes and technology that the company relies on to execute its capital plans and operational programs in a safe, effective and efficient manner. This approach also helps reduce IT related operational and capital expenditures.

D5.1.2 IT Software Standards

Under Toronto Hydro's IT software standards, software applications are categorized as Tier 1 and Tier 2 based on the operational criticality of the application, level of complexity, integration with other applications, maintenance costs and number of users.

- **Tier 1** applications enable Toronto Hydro's business operations and support company-wide business processes. They are functionally integrated with other applications, and are supported by complex underlying infrastructure such as databases, middleware, storage and network. As a result, Tier 1 applications generally have higher maintenance costs and a large user base. In a disaster scenario, the recovery point objective is less than 4 hours. Examples of Tier 1 applications include the Enterprise Resource Planning System, Inventory Management System and Geospatial Informational System.
- **Tier 2** applications enable specific divisional and departmental processes. These applications have little to no integration with other enterprise applications, and are typically supported by relatively simple infrastructure. In a disaster scenario, the recovery point objective is less than 24 hours. Tier 2 applications generally have lower maintenance costs, and cater to a smaller user base than Tier 1 applications. An example of a Tier 2 application is Hydropedia, a knowledge base system that helps customer service

representatives quickly and accurately address customer questions about Toronto Hydro processes during a phone call.

Regular software upgrades reduce the risk of system failures and cyber security breaches, and align software assets with vendor support cycles. Similar to IT hardware assets, if an application is not upgraded before the vendor support cycle expires, Toronto Hydro may have to procure specialized technical resources to maintain and support the application. These upgrades also reduce IT related operational and capital expenditures.

Through its IT software standards, the company also seeks to maintain the compatibility of software applications and the underlying components (e.g. servers and operating systems) to ensure uninterrupted IT system operations and deliver the desired end user experience and functionality. Because IT systems and their underlying components are often on different end-of-life and vendor support cycles, maintaining compatibility can be a complex task. Nonetheless, it is a key consideration in mitigating security and failure risks to IT systems from the underlying components.

IT software standards take into account average vendor release cycles, as well as the need to minimize incompatibility risks with underlying components. Software asset upgrades could be triggered if the asset reaches its maximum age, if the asset is more than one version behind the latest vendor-released version, or based on specific compatibility drivers and considerations (e.g. hardware upgrades).

D5.2 IT Investment Planning

IT investment planning is the process of developing a five-year program of prioritized investments, including a detailed plan for the first year. Toronto Hydro's IT investment planning process is divided into two streams: (i) sustaining existing systems; and (ii) enhancement initiatives.

The primary objective of Toronto Hydro's IT investment planning process is to maintain the IT assets that are required to satisfy optimal IT system reliability and availability. The sustainment stream is intended to provide satisfactory levels of service for customers and the utility, and mitigate IT-related business and operational risks (e.g. non-compliance and failure impact) in a cost efficient manner.

A secondary objective is to maximize cost savings through enhancement initiatives. Enhancement initiatives enable Toronto Hydro to leverage technological solutions to optimize or enhance business operations in order to ultimately deliver greater value to customers, and to ensure compliance with new or modified external requirements from entities such as Measurement Canada, the Ontario Energy Board ("OEB"), and the Independent Electricity System Operator ("IESO").

D5.2.1 Sustaining Existing Systems

The scope and timing of IT sustainment investments is based on IT standards and asset specific information stored in Toronto Hydro's electronic IT assets inventory system. The utility makes investment decisions based on structured and up-to-date IT asset information, including: hierarchy of assets and interdependencies, key dates in each asset's lifecycle, vendor, contract and licence information, and capacity planning data.

IT system criticality (i.e. the impact of system failure) is the main consideration for purposes of investment prioritization. Priorities are also informed by internal program dependencies, asset type complexity, and resource balancing.

In making IT investment planning decisions, Toronto Hydro may also consider additional factors relating to general business growth and associated increase in IT requirements, such as process re-engineering, historic trends of current assets capacity versus utilization by existing IT systems.

D5.2.2 Enhancement Initiatives

As part of its commitment to continuous improvement, Toronto Hydro regularly evaluates and considers opportunities to enhance business processes based on new IT solutions.

Prior to investing in new IT systems, Toronto Hydro follows an evaluation process to help ensure that the utility makes well-informed decisions relating to new IT investments. That process includes the following steps:

1) **Evaluate:** The utility validates the proposed initiative, and works with the relevant business unit(s) to determine the project scope, business requirements, current state business processes, future state business processes, the options to achieve the future state and the preferred approach, costs and benefits.
2) **Align***:* Toronto Hydro reviews the proposed project to help ensure the following:
    - Governance, due-diligence, rationale and accuracy of the project costs and benefits;

   - Strategic alignment with Toronto Hydro's objectives (e.g. value for money);
   - Alignment with Toronto Hydro's risk profile (e.g. cyber security); and
   - Alignment with existing technology investments and standards.
1) **Prioritize:** Toronto Hydro prioritizes the project based on a combination of factors, including project dependencies, costs, benefits, strategic alignment and risk assessment.
2) **Execute:** Project execution typically consists of the following steps:
   - Gathering more detailed user and technical requirements;
   - Mapping the relevant business processes;
   - Developing and/or procuring the application as needed;
   - Provisioning the infrastructure to host the application;
   - Configuring the application to meet business requirements;
   - Testing the application for compatibility with Toronto Hydro's infrastructure;
   - Engaging users to test that the application meets their business and functional requirements;
   - Training users on the features and functionality of the application; and
   - Implementing the application across the appropriate departments.

D5.3 Five-Year IT Investment Plan

The output of Toronto Hydro's IT investment planning process is a five-year IT investment plan that: (i) is expected to deliver optimal levels of IT system reliability and availability; (ii) complies with the utility's IT standards and asset management practices; and (iii) mitigates risks related to IT assets in a cost efficient manner.

In developing its IT plan, Toronto Hydro has also considered IT industry best practices, vendors' information, distribution capital program growth and overall business growth, as well as trends of evolving regulatory requirements. Based on the overall schedule and cost estimates contained in the five-year IT investment plan, the utility develops a detailed plan for the next year which lists, prioritizes, and tracks all the key investment initiatives while in execution.

Toronto Hydro's IT capital investment plan incorporates some level of flexibility in order to manage externally-driven risks, such as an increase in software and/or hardware costs over the 2020 to 2024 period or a change in the release dates for certain applications; new threats, vulnerabilities, or modes of cyber security attacks; and unpredictable nature of new or evolving requirements from regulatory bodies such as the OEB, Measurement Canada and the IESO. For example, the OEB's Policy Review of Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance[1] resulted in a number of significant changes (e.g. the implementation monthly-billing) to the customer billing system. Any of these events could affect the cost, timing and pacing of a program in a given year.

Furthermore, the technology landscape evolves at a fast pace with new products frequently entering the market. If new technologies that are relevant to Toronto Hydro become available during the 2020 to 2024 period, Toronto Hydro plans to evaluate and consider these new technologies.

[1] EB-2014-0198, Ontario Energy Board Amendments to the Distribution System Code (April 15, 2015).

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED (“THESL”)

Distribution System Plan Asset Management Review

SECTION I - INTRODUCTION

The Ontario Energy Board's ("OEB" or "the Board") Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements state an expectation that "the DS Plan optimizes investments and reflects regional and smart grid considerations; serves present and future customers; places a greater focus on delivering value for money; aligns the interests of the distributor with those of customers; and supports the achievement of public policy objectives."

Furthermore, the Board wants to ensure that its established performance outcomes for electricity distributors are being achieved. Specifically, these outcomes include:

- Customer Focus: services are provided in a manner that responds to identified customer preferences;
- Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
- Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
- Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

A specific requirement of the Board for the Distribution System Plan ("DSP") is for the Electricity Distributor to explain its asset management process in order to provide the Board and stakeholders with an understanding of not only the processes themselves but how they create and drive the expenditure decisions in the DSP. The objective is to allow the Board to assess whether and how a distributor's DSP delivers value to customers, including controlling costs through optimization, prioritization and pacing of capital-related expenditures based on the condition of the assets and their ability to meet the specified performance outcomes.

Implicit in the Board's requirements is that the filing utility's DSP be based on sound asset management principles. To that end Torys LLP ("Torys"), acting on behalf of Toronto Hydro-Electric System Limited ("THESL" or "the Company"), engaged UMS Group to evaluate its asset management practices as they relate to the formation and execution of its DSP.

Overview

UMS Group completed personnel interviews and reviewed the relevant sections of THESL's 2020-2024 DSP Filing in order to evaluate the asset management practices that THESL used to develop its Distribution System Plan (DSP).

The purpose of these interviews and the document review was to gain an understanding, from an asset management perspective, of how the DSP was constructed. The objective was to gather information that UMS could use to evaluate whether the aspects of the asset management system relevant to the construction of the DSP are in alignment with industry standard practices per ISO 55001. ISO 55001 is the global industry standard which specifies the requirements for the establishment, implementation, maintenance and improvement of a management system for asset management of physical assets. It was used as a basis of comparison to provide a level of objectivity to the evaluation of THESL's Asset Management practices.

From the interviews and the review of DSP documents, UMS qualitatively evaluated where it believes Toronto Hydro's maturity level currently is across the relevant domains within the standard. In order to provide some external context to its evaluation, UMS scored THESL's asset management maturity using the ISO 55001 maturity scale and compared it to a group of 14 North American electric utility business units for which UMS Group has previously performed asset management assessments.

The bases for UMS's findings include insights formed in working with other electric utilities worldwide in developing and implementing asset management capabilities, along with its formal expertise as an IAM Endorsed Assessor for ISO 55001 certification.

UMS Group Qualifications

UMS Group, headquartered at 300 Interpace Parkway, Parsippany, NJ, 07054, has been a leading provider of utility asset management services for over 25 years. UMS published its first report on this topic – the ISAM Report ("International Strategic Asset Management") in 1992 after conducting a worldwide search for best practices in utility asset management.

In the decades since, UMS Group has performed over 200 utility projects covering the full gamut of asset management. These include asset management gap assessments, multi-year large scale company-wide asset management transformations, development and implementation of asset management Operating Models, development of guiding documents/strategies (i.e., AM Policies, Strategic Asset Management Plans, Asset Management Plans, etc.), definition and implementation of asset management processes, and development and implementation of asset management tools (i.e., economic models, portfolio optimization tools, risk management tools, etc.)

UMS has developed and continually adapted its assessment methodologies to align them with emerging industry standards. In August 2010, UMS Group, as one of the first 11 firms so named, was appointed an Endorsed Assessor for the PAS 55 standard by the Institute of Asset Management (IAM), the professional body of those involved in the acquisition, operation and care of physical assets – particularly critical infrastructure. The Endorsed Assessor designation followed a rigorous IAM review of the expertise, practices, tools and techniques which UMS Group applies to asset management compliance assessments. UMS Group has since been appointed an Endorsed Assessor and Endorsed Trainer for the ISO 55000/1/2 standard by the IAM. **Appendix A** provides additional details regarding UMS Group's qualifications and those of the individual assigned to this effort.

The UMS Group-assigned expert for this effort, Mr. Steven Morris, fully acknowledges his duties as an expert in accordance with Rule 13 and Form A of the Ontario Energy Board's ("OEB" or

"Board") Rules of Practice and Procedure. In so doing, he acknowledges that it is his duty to provide evidence in relation to this report as follows:

- To provide opinion evidence that is fair, objective and non-partisan;
- To provide opinion evidence that related only to matters that are within his area of expertise; and
- To provide such additional assistance that the Board may reasonably require, to determine a matter in issue.

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

Structure of the Report

The ensuing discussion is divided into three sections:

- Section II – Executive Summary: A summarization of UMS's conclusions on the maturity of THESL's asset management practices used to develop its 2020-2024 Distribution System Plan (DSP),
- Section III – Project Approach: A description of and rationale for the approaches, methodologies, criteria and frameworks used to evaluate THESL's asset management maturity relative to development of the DSP
- Section IV – Summary of Results: An expanded discussion of findings, conclusions and recommendations around the topic of asset management.

SECTION II – EXECUTIVE SUMMARY

Overview of DSP Asset Management Review

UMS Group was retained to evaluate THESL's asset management practices as they relate to the formation and execution of its DSP. In accomplishing these objectives, UMS Group:

- Conducted a series of interviews with several THESL stakeholder organizations (e.g.; Planning Integration, Investment Planning, System Planning, Standards and Technical Studies, Program Management, Engineering Services, Fleet, Facilities, IT, etc.),
- Reviewed the relevant sections of the 2020-2024 Distribution System Plan filing,
- Evaluated THESL's asset management capabilities per the ISO 55001 domains relevant to the DSP,
- Compared THESL to a group of 14 electric utility business units on their asset management maturity per the ISO 55001 standard,
- Analyzed the results of the interviews, DSP review, and asset management assessment.

Evaluation of THESL's Asset Management Capabilities as Applicable to the DSP

Toronto Hydro has been developing its asset management capabilities for a number of years and exceeds the North America average level of maturity in all relevant areas, even reaching into "Best Practice" for North American utilities for some domains. In general, North American utilities are not as advanced in the discipline of asset management as global leaders in Northern Europe, Australia, and New Zealand, although there is a large degree of variance in the maturity of specific utilities.

Furthermore, THESL has clearly adopted the principle of continuous improvement such that it strives to 1) use asset data to optimize the decisions is makes about its assets, and 2) identify opportunities to improve operational effectiveness.

In UMS's numerous assessments of asset management maturity, one of the areas in which UMS has found that utilities have the most difficulty is in translating Strategic Objectives into Actions at the asset level. There is often a disconnect between what outcomes Leadership wants to achieve and what work is actually performed. However, this does not seem to be an issue for THESL. Senior Leadership has defined clear strategic objectives which are directly addressed in decisions made around Programs for the DSP. In addition, the Strategic Objectives have been directly linked to the Performance Outcomes enumerated in the Board's Chapter 5 filing requirements – Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance. This link helps ensure that asset-based decisions in the DSP meet both Utility and Stakeholder interests.

To ensure that the decisions made are delivering on the objectives, THESL continues to improve its performance management framework to track performance of its annual investment program. For this DSP filing, THESL is developing capabilities to measure performance in terms of outcomes in order to be able to demonstrate the link between the plan and programs, and the outcomes, as well as to measure the efficiency in achieving the outcomes.

THESL's asset lifecycle processes used to identify projects to be included in the DSP programs is at a higher than average level of maturity and is moving towards best practice. Lifecycle planning, risk assessment, maintenance optimization, and asset condition assessment are all key asset management processes which THESL uses to identify and evaluate projects to be included in the DSP. Economic analysis, stakeholder outcomes, and operational effectiveness are all considered in prioritizing projects for inclusion in Programs.

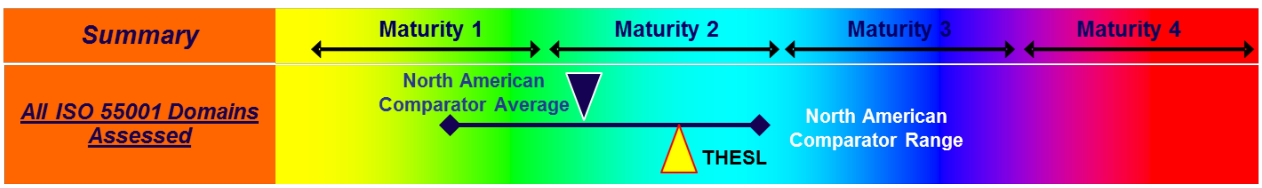
THESL's asset management processes include a variety of quantitative and qualitative analyses including the analysis of Customer Interruption Costs and the direct costs of responding to a failure, as well as ranges of customer outcomes related to reliability, safety, the environment, and financial impacts. While quantitative methods are used to identify projects, the methodology used for prioritizing individual projects is largely qualitative, as the desire to address a variety of stakeholder-driven outcomes precludes the use of a single (i.e., economic) measure. This demonstrates a level of maturity in translating customer needs and expectations into decision-making that exceeds most North American utilities. THESL also has a well-defined process for decision-making and the prioritization of projects as input to DSP Programs. This process ensures that needs and risks are assessed as required by industry standards. In alignment with ISO 55001 requirements, roles and responsibilities for the creation and execution of the DSP are clearly defined.

Asset management is a data-driven discipline and a higher level of maturity means incorporating quantitative analysis into decision-making using data – asset data, work data, customer data, cost data, system data, etc. While, UMS did not directly examine THESL's data, through information gathered in the interviews it appears that THESL's data for major asset classes is generally thought to be good. As with the industry as a whole, the quality of THESL's data varies among different asset classes. However, for the major asset classes, THESL's data appears to be sufficient for supporting its asset management decision-making processes. In addition, THESL strives to continuously improve the quality of data. For example, Mobile Data Terminals are being used to collect inspection data, and during the inspection, existing data is validated and the condition of the asset is noted. Where other data gaps in the asset register exist (e.g., asset age), predictive algorithms are being used to estimate data values.

From an Enabling Technology perspective, THESL is generally more mature than the typical utility with good modeling and Business Intelligence tools for performing lifecycle analysis, as well as forecasting failures and their impacts. UMS considers the Feeder Investment Model and Reliability Projection Methodology as examples of best practice asset management analytical techniques. In addition, Asset Condition Assessment has moved from a relatively simplistic model to a more sophisticated one which would be considered to use best practice techniques.

While THESL's asset management practices used to develop the DSP are above average, there are still some opportunities for improvement to achieve best practice levels. First, while the asset management system is well-defined, the level of documentation could be improved to ensure sustainability over the long-term. Second, while THESL does a good job addressing risk at both the corporate and DSP level, the methodology THESL uses for assessing and tracking the risk of deferred investment is not a highly standardized process. In addition, asset class level risk registers and an associated asset risk assessment process would assist THESL in being more proactive in ensuring risks beyond reliability are kept within tolerances. Finally, THESL's current portfolio optimization approach is manual, while the industry is moving to using tools which can provide a more comprehensive, programmatic optimization analysis that provides greater transparency into trade-offs.

In order to provide context to its qualitative evaluation of the extent to which THESL's asset management system aligns with the standard for good asset management, UMS also scored THESL's asset management maturity on the ISO 55001 scale and compared it to a database of 14 transmission and/or distribution utility business units for which it had previously conducted asset management maturity assessments. Across the ISO 55001 domains assessed, THESL's average maturity level is a 2.1, while the North American Comparator Average is a 1.6. The range of average maturity levels for the individual comparators ranges from 1.1 to 2.4. The result from the comparison of THESL's maturity scores versus the comparator group confirms and is in alignment with UMS's qualitative assessment of its relevant asset management practices, most of which exceed the industry standard and some of which are in alignment with best practices.

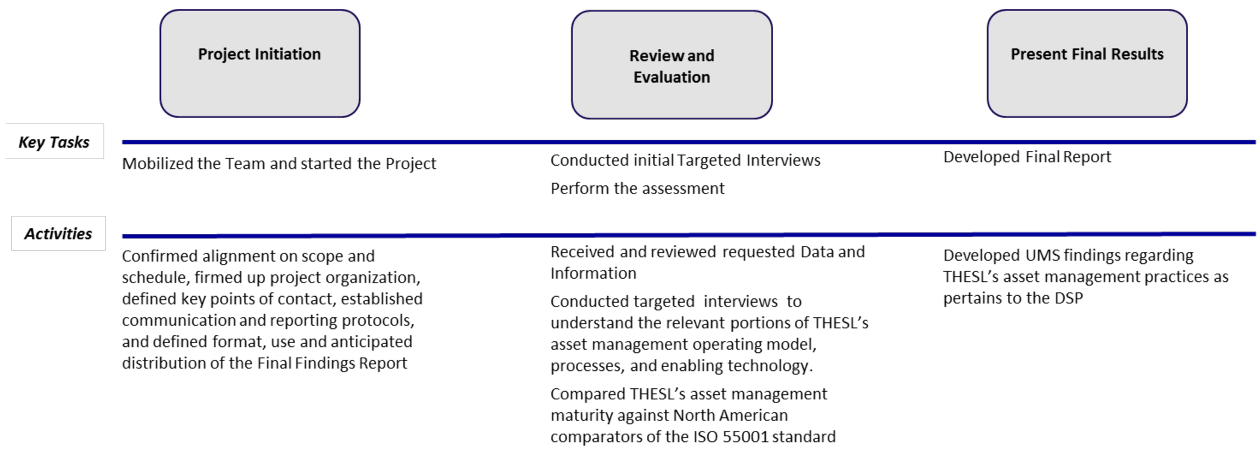


It should be noted that this finding is only against the 11 ISO 55001 domains assessed, not the full 24 domains within ISO 55001. The reason for this subset is that not all aspects of asset management are directly involved in the development of the DSP, and THESL desired a focus evaluation, rather than a more general one. These 11 domains represent the asset management domains that a utility should be using to create a capital plan like the DSP. That being said, and given that UMS did not specifically assess the other 13 ISO 55001 domains, UMS's view, based on the interviews and documentation review performed, is that THESL would likely exceed the industry average across most, if not all, 24 domains as well. However, that assessment is not specifically supported by this review.

SECTION III – PROJECT APPROACH

UMS Group implemented the following Project Work Plan (Figure III-1) to review THESL's asset management practices as relevant to the DSP and evaluate them against the ISO 55001 standard to provide an independent opinion on their competence:

Figure III-1: DSP Asset Management Review Overview



From Project Initiation to the Presentation of Results, UMS Group applied several elements of its endorsed and time-tested asset management assessment methodology to independently evaluate THESL's asset management maturity for those domains relevant to the DSP. The following discussion will expound on those aspects of UMS's approach that contributed to UMS achieving the level of objectivity and relevance needed to provide an independent review.

Practices Assessment

UMS Group met with a number of organizations within THESL (e.g.; Planning Integration, Investment Planning, System Planning, Standards and Technical Studies, Program Management, Engineering Services, Fleet, Facilities, IT, etc.) to gain insights and perspective regarding the asset management practices it uses to develop the DSP. UMS also received demonstrations of some of the key tools used to perform analyses to support decision-making around the DSP. A standard practice of most of UMS's assessment engagement is to perform interviews and review documentation to understand what and how a utility practices asset management. UMS has well established frameworks and interview guides to determine the relative maturity of practices versus the ISO 55001 standard.

DSP Domains

In order to evaluate the application of asset management principles to the development and execution of the DSP, UMS Group identified a number of asset management domains (Table III-1) which are relevant to the efforts undertaken. These domains formed the basis of UMS's evaluation of asset management maturity, as each was assessed individually against both the relevant ISO 55001 standard and UMS's experience gained from working with numerous North American electric utilities.

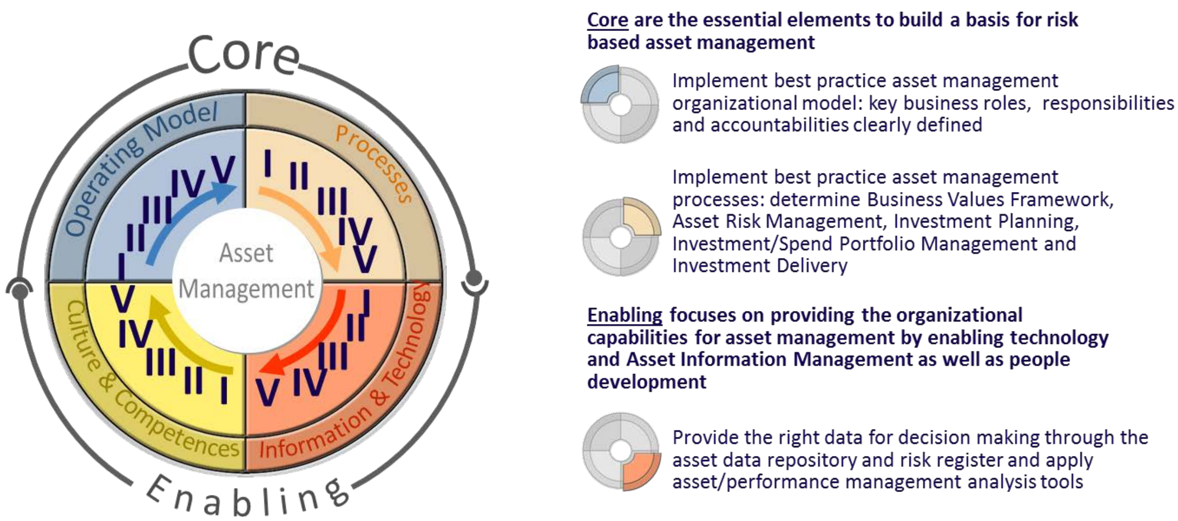
Table III-1: DSP Review Domains

Alignment of Strategy, Objectives, and Initiatives	Line-of-Sight Performance Objectives
Asset Management Systems and Tools	Performance Management
Application of Asset Management Processes	Resource Strategy and Plan to Execute the DSP
Application of Risk to Decision-making	Risk Tolerance
Business Value Framework	Role Clarity in Developing the DSP
Data Collection and Management	Scope of the AM System
DSP Feasibility	Stakeholder Management
DSP Formulation	Strategic Objectives

Strategic Asset Management Model

As an organizing framework, UMS Group used its proprietary Strategic Asset Management (SAM) Model (Figure III-3) which aggregates individual ISO 55001 domains into a holistic, risk based management model for asset-intensive businesses. The model embodies a well-defined organization structure, set of management processes, performance framework, and supporting information systems. The model also aligns with ISO 55001 and puts the key elements of ISO 55001 into a framework that more easily enables understanding of gaps and application of recommendations to improve the asset management system.

Figure III-3: Strategic Asset Management (SAM) Model



Evaluation Model

In defining the framework used to perform the review, UMS linked the DSP domains evaluated to the Strategic Asset Management Model domains. Similarly, the corresponding ISO 55001 Standard domains were linked to the corresponding Strategic Asset Management Model domains. This framework provides a holistic way to directly tie the DSP review to ISO 55001 in a more holistic and understandable format (Table III-3).

Table III-2: Relationship between ISO 55001, SAM Model, and DSP Domains

DSP Domain	Strategic Asset Management Model Domain	ISO 55001 Domain
Strategic Objectives, Business Value Framework, Stakeholder Management	Operating Model	4.2 Understanding the Needs and Expectations of Stakeholders
Scope of the AM System		4.3 Determining the scope of the AM system
Risk Tolerance		5.1 Leadership and Commitment
Role Clarity in Developing the DSP		5.3 Organizational Roles and Responsibilities
Performance Management		10.3 Improvement
DSP Formulation, Application of AM Processes	Processes	6.2 Asset Management Objectives and Planning
Resource Strategy and Plan to Execute the DSP		7.1 Resources
Application of Risk to Decision-making		6.1 Actions to Address Risks and Opportunities
DSP Feasibility (i.e.; Portfolio Execution)		8.1 Operational Planning and Control
Alignment of Strategy, Objectives, and Initiatives. Line-of-Sight Performance Objectives		9.1 Monitoring, Measurement, Analysis and Evaluation
Data Collection and Management, AM Systems and Tools	Enabling Technology	7.5 Information Requirements

ISO 55001 Maturity Scoring

To perform the comparative evaluation against the utility comparators, UMS Group used the ISO 55001 Maturity scale (Figure III-2) as the standard to assess asset management practices as they relate specifically to the Distribution System Plan (DSP). This scale was used for both THESL and the other assessed comparator utilities.

Figure III-2: ISO 55001 Maturity Scale

Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
The organization has not recognized the need for this requirement and/or there is no evidence of commitment to put it in place.	The organization has identified the need for this requirement, and there is evidence of intent to progress it.	The organization has identified the means of systematically and consistently achieving the requirements, and can demonstrate that these are being progressed with credible and resourced plans in place	The organization can demonstrate that it systematically and consistently achieves relevant requirements set out in ISO 55001.	The organization's processes and approaches go beyond the requirements of ISO 55001.

In order to be certified as ISO 55001 compliant, a company must be at Maturity Level 3 in all of the ISO 55001 domains. It should be noted that to date, UMS Group knows of only one North American utility business unit which has been ISO 55001 certified – PG&E Gas Operations. Therefore, UMS's intent was not to compare THESL against the certification level of maturity, but rather against the North American utility industry. To do so in a quantitative manner, UMS Group compared THESL against a comparator group made up of 14 North American electric utility business units for which it has performed asset management assessments (Table III-3). While these utilities were not specifically selected to represent the industry as a whole, as a consultancy who has performed scores of such assessments, UMS believes that the results are consistent with its qualitative view of asset management maturity across the North American utility industry.

Table III-3: North American Electric Utility AM Maturity Assessment Comparator Group

Avista Utilities – Distribution	Nova Scotia Power – T&D
Avista Utilities – Transmission	PowerStream – Distribution
EPCOR – Distribution	PSEG LI - Distribution
Lansing Board of Water & Light – T&D	PSE&G - Distribution
Manitoba Hydro – Distribution	Sask Power – T&D
Manitoba Hydro – Transmission	Southern California Edison - Substations
NB Power – T&D	Tennessee Valley Authority - Transmission

SECTION IV – SUMMARY OF RESULTS

The following discussion summarizes the results of an approach that:

- Utilized UMS Group's endorsed and time-tested asset management assessment methodology,
- Drew upon UMS's extensive experience performing asset management assessments and helping develop and implement asset management competencies and tools for utilities, and
- Captured insights and perspectives from key management and staff within the THESL organization.

Review of THESL's Use of Asset Management in the DSP

This section provides UMS's evaluation of the asset management maturity of the key domains which it believes are relevant to development and execution of THESL's 2020-2024 DSP Plan. These domains have been grouped into three areas of the UMS SAM Model – Operating Model, Processes, and Enabling Technology.

OPERATING MODEL

<u>Clarity of Roles and Responsibilities</u>

THESL has clearly defined the roles and responsibilities around asset management and has defined accountability for creation and execution of the DSP. This helps ensure that all necessary process steps to develop the DSP are performed and that decisions are made at the appropriate level. There is a designated responsible person for each of the DSP programs who is responsible for key decisions and actions around each Program. This provides THESL with greater accountability than much of the industry which typically relies on a committee-based approach for decision-making. While committees are good for achieving consensus, they do not provide accountability for decisions or actions which is a requirement for good asset management. In defining programs, alternatives are identified and analyzed to determine how they can help meet objectives. In addition, the decision-making criteria that is applied to this analysis is appropriate for the importance and complexity of the decisions being made. The use of alternative analysis and appropriate decision-making criteria provide both more consistency and transparency in DSP development.

<u>Scope of the Asset Management System</u>

THESL has identified the key assets to be covered by the asset management system, taking into account relevant internal and external issues, and addressing the needs and expectations of stakeholders. The scope of the asset management system is driven by the importance and level of risk around the assets and ensures that asset management processes are applied to the Program assets (i.e., Distribution Infrastructure, IT, Facilities, and Fleet) in the DSP. Similarly, the level of analysis used to develop programs is increased for the major assets which drive outcomes and are a larger portion of the capital spend. While THESL's asset management system is fairly well defined, the level of documentation around some parts of it could be improved to ensure sustainability.

Incorporation of Strategy and Business Value Framework

THESL has a good understanding of stakeholder needs and expectations and includes them in its decision-making criteria. The process used to develop Programs for the DSP is directly and clearly linked by line-of-sight to the strategic objectives which are based on an assessment of Stakeholder needs and expectations. The outcomes-based framework is based on stakeholder input and directly aligned with the four performance outcomes the Board has established for electricity distributors. Not only does the link between Programs and the outcomes-based framework provide confidence that the DSP addresses the Board's performance requirements, but THESL's process for defining strategic objectives, aligning them with stakeholder needs, and formalizing them into a framework to support asset-related decisions (such as development the DSP) is one of the most thorough and comprehensive that UMS has seen in the North American utility industry.

Application of Risk Tolerance Framework

A corporate risk matrix and tolerance levels have been established and needs and risks are assessed qualitatively as part of project prioritization. In addition, risk is used to identify projects and build programs, as well as to assess feasibility and manage implementation of the DSP. The process around risk management provides assurance that risk is being addressed in constructing the DSP. And while many utilities have a corporate risk matrix and established tolerance levels like THESL, not as many use risk as extensively to drive asset management decisions, nor have many "monetized" risk to be able to calculate a dollar-based risk reduction value as THESL has. At the same time, while risk is used to identify projects and build programs, assessment and monitoring of the risk of deferred investments beyond reliability impacts is not performed using optimization techniques that would align with best practice.

Line-of-sight Performance Management

THESL's asset management process ensures that objectives flow down throughout the organization to individual goals to ensure Line-of-Sight alignment. In addition, a process exists to ensure that performance aligns with the objectives and Management has a monthly review of the asset management system to ensure that it is performing acceptably. Finally, a new initiative will improve tracking of costs and link outcomes to projects to enable continuous improvement. This Performance Management framework around the DSP demonstrates that THESL is striving to identify opportunities to achieve continuous improvement.

Stakeholder Management / Benefit Capture Framework

THESL undertakes both formal and informal efforts to identify stakeholder needs and expectations. Stakeholders have been identified – Customers, Regulator, City, Province, Employees – and their requirements and expectations have been defined through multiple avenues, both formal and informal. Stakeholder needs are reflected in the decision-making framework ("outcomes framework") and are well communicated to the personnel who make the decisions so that they are kept informed on stakeholder needs. The process used to engage stakeholders, identify their needs, and translate them into outcomes helps ensure that the DSP aligns the interests of the Distributor with those of customers and public policy. In addition, THESL's benefits capture framework exceeds what is typically seen in the industry in terms of formally translating these needs and expectations into desired outcomes which are linked to DSP Program development. To achieve best practice, THESL would need to measure the results of its efforts against the desired outcomes and use deviations to drive performance improvement initiatives. This is an action which THESL has said it plans to undertake for the 2020-2024 period.

PROCESSES

Distribution System Plan Formulation

THESL has a well-defined process for creating the DSP that takes into account needs and risks as part of its prioritization process and links decisions to its objectives. asset management is integrated with Financial and Business Planning to achieve the strategic objectives. The Programs take into account requirements from outside the asset management system such as financial constraints, resource constraints, and legal/regulatory constraints. Individual projects are identified through a variety of qualitative and quantitative analyses, and comparing individual projects puts a strong reliance on subject matter experts to make the right choice.

For Distribution, condition assessment is a key driver for plan development, with the level of condition assessment used to drive DSP programs varying for different asset classes. For Fleet, lifecycle replacement timing drives development of the plan based on current vehicle mix and age. For IT, equipment is replaced on a fixed lifecycle schedule. Applications are prioritized based on business case analysis of alternatives incorporating risk. For Facilities, the program is driven by poor condition assets, age, and criticality. Overall, the processes used to formulate the DSP provide confidence that it was created using sound asset management techniques.

THESL uses an optimization, rather than prioritization approach to its Program portfolios which exceeds what is typical in the industry. However, THESL's current optimization approach is manual, while the industry is moving to using tools which can provide a more comprehensive, programmatic optimization analysis. THESL has recognized this improvement potential and has said it is exploring opportunities to move to a more automated methodology to ensure that it is selecting the projects and overall portfolio which will deliver the most value against the desired outcomes.

Distribution System Plan Feasibility

THESL's practices for assessing the feasibility of the DSP are in alignment with or exceed industry standard practice. Senior Leadership sets objectives and selects the level of funding for Programs. Outcomes are modeled to determine if Programs meet objectives and if not, the Program goes back to Designated Responsible Person with a request to assess changes to Programs or alternatives. The evaluation of Programs to determine if they can deliver on the objectives despite constraints, as well as the costing out of the Programs using high-level average costs is consistent with the approach used by most of the industry.

THESL's practices around ensuring delivery of the DSP border on best practice in terms of having a cross-functional Project Development Group to develop cost estimates, conduct constructability reviews, develop execution strategies, and gain stakeholder agreement. This is also true for the Program Management group which matches projects to the resource pool, uses resource availability to schedule projects, and makes decisions whether to use internal or external resources.

THESL treats and monitors risks identified through a risk assessment of each project. Risks are also assessed at the program level where a mitigation strategy is developed and monthly reporting performed. This use of individual project risk assessments, program risk assessments, and avoidance of contingencies built into budgets is a more sophisticated way of managing implementation risk than used at most utilities. Overall, the process used to assess and manage DSP feasibility provides a high degree of confidence that the DSP will be achieved.

Performance Management

THESL has a process which provides line-of-sight to corporate objectives and ensures that the assets and the asset management system are performing as expected and achieving targeted stakeholder outcomes. The performance of both capital and maintenance work is also tracked to ensure compliance with asset management strategies and programs, as well as to drive continuous improvement in execution efficiency and effectiveness. In addition, for the 2020-2024 DSP, THESL will link projects to outcomes to track that they deliver cost-effective benefits to customers. This performance management framework of THESL's is in alignment with best practice asset management in terms of linking strategy to actions and measuring the results. The performance management framework also helps ensure THESL is meeting the objectives established in the DSP. While most utilities measure performance, many find it difficult to link the actions directly to the utility's strategic objectives. In addition, many utilities do not have a good performance feedback loop to ensure that non-conformities and opportunities for improvement are identified and addressed. THESL has both parts of the process and is continually increasing the use of performance results to drive improvement.

Application of Asset Management Processes

THESL has a number of key asset management processes which are used in developing the DSP. Asset risk management is performed as part of lifecycle optimization, as well as in response to specific incidents, and critical assets have a more targeted risk assessment focused on them. Lifecycle planning is performed across all the divisions to understand the trade-offs between alternatives and optimize on cost, performance, and risk. Maintenance strategies are developed through RCM and lifecycle analysis, where appropriate, and adjusted as necessary. Asset Condition Assessment has transitioned from a relatively simplistic model which is consistent with industry standard practice to a more sophisticated one which uses best practice techniques. Failures are forecast and reliability projections are used to understand medium- and long-term threats from asset failure which is then used to guide Program development. Assets are not just assessed individually, groups of assets are assessed to identify opportunities to replace assets in a more cost efficient manner (i.e., area replacement). Monetized risk models exist and are used to identify risk and develop the economic business case for decisions. As a whole, the asset management processes provide confidence that the DSP delivers value to stakeholders by optimizing decisions from an asset lifecycle perspective and balancing risk with cost and performance.

The use of lifecycle planning to understand the trade-offs between alternatives and optimize on cost, performance, and risk; the use of failure forecasting to develop reliability projections; and the use of monetized risk models to assess the financial cost/benefit of projects are all examples of practices that exceed what is typically found in utility asset management programs. The new asset condition assessment model (based on CNAIM) is in alignment with best practice techniques. Outside of the Distribution System assets, Fleet's asset management processes are consistent with the level of maturity typically found in the utility industry in this domain. IT's performance of risk assessments, lifecycle analysis, and business cases exceeds industry standard practices for this domain. Facilities' use of lifecycle analysis, failure-based maintenance strategies, asset condition assessments, and criticality and risk assessment place it above the average utility Facilities organization in asset management competence.

ENABLING TECHNOLOGY

Data Collection and Management

THESL has identified the data needed to support its asset management activities and has implemented technology to assist in collecting and managing that data. Data quality is reported to vary by asset class, but is generally thought to be good for major assets. While, UMS did not directly examine data, through its interviews, UMS determined that the quality of data THESL uses to supports its asset management decisions and practices, including formulation of the DSP, is consistent with the industry as a whole. As is common in most utilities, data quality varies by asset class, but is generally good for major assets, particularly asset classes with small numbers of expensive assets. Having sufficient and reasonable quality data helps assure the accuracy of the decisions that the DSP is built upon. To continue moving towards best practice in data collection and management, THESL continues to develop data quality measures and address deficient data needed to improve decision-making.

Asset Management Systems and Tools

THESL has the necessary tools and models to perform best practice asset management analyses. In some cases, THESL exceeds industry standards with its tools and models, such as those used to support key asset management analyses such as asset health indexing, lifecycle costing, risk costing, economic analysis, and reliability analysis. THESL is also using best practice Business Intelligence tools to develop Programs that are more efficient. THESL has an asset register to capture asset data for each asset type (e.g., Distribution, Fleet, Facilities, IT, etc.) and a risk register exists at the corporate level. While this use of an asset register and a corporate risk register to support asset management are in alignment with typical industry practices, best practice would be to have an asset risk register to track risks for individual asset classes. Overall, the application of systems and tools to perform needed asset management analyses provides confidence that the DSP is data-driven and based on appropriate asset lifecycle analysis.

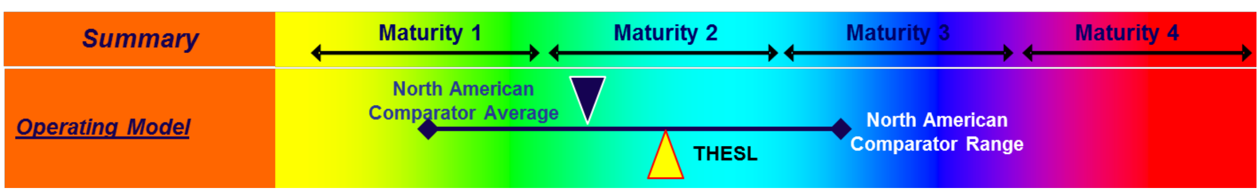
Comparison of THESL to Comparator Group

In addition to the evaluation of THESL's application of asset management to the development and execution of the DSP, UMS assessed the maturity of THESL's asset management capabilities against the international standard, ISO 55001. For reference purposes, UMS used a group of 14 North American utilities ("comparators") for which it had previously performed asset management maturity assessments. While these utilities were not specifically chosen as a representative sample of the electric utility industry, based on UMS's experience performing utility asset management assessments, as well as assisting utilities in building their asset management capabilities, it believes the results are a reaonably accurate representation of the North American industry.

In order to make the results more meaningful from a holistic perspective, UMS aggregated the scores across the domains in the Strategic Asset Management (SAM) Model.

The Operating Model domain assesses the extent to which the asset management system aligns with ISO 55001 standards for good asset management in terms of the definition and distinction between roles, responsibilities, and accountabilities. It also evaluates the consistency between overall strategy, the underlying philosophy in managing the assets, and the deployment of personnel in capturing the value of installed assets. Finally, it assesses the degree to which stakeholder needs and expectations are captured and used to drive business decisions.

Across the sub-domains which make up this domain (see Table III-3), UMS scored THESL as an average 2.0 maturity, while the comparator group average was 1.6. The maturity level of individual comparators (averaged across the sub-domains) ranged from 1.0 to 2.7.



THESL's scores in the five ISO 55001 domains which make up this aggregated score range from 1.8 to 2.5. As Table IV-1 below demonstrates, THESL's asset management maturity exceeds the comparator group average maturity in all the sub-domain areas that make up the Operating Model domain.

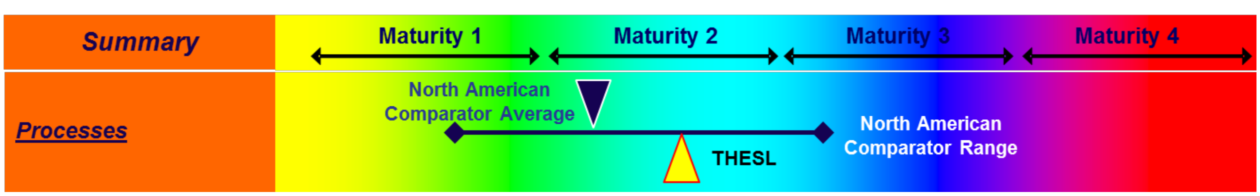
Table IV-1: Comparison of THESL against Comparators (Operating Model)

ISO 55001 Domain (SAM Domain)	Maturity Level 3 per Standard	UMS Assessment of THESL	THESL Maturity	Comparator Avg. Maturity
4.2 Understanding the Needs and Expectations of Stakeholders (Operating Model)	The organization identifies stakeholders that are relevant to the AM system, and captures their requirements and expectations. The organization determines criteria for AM decision making which includes where appropriate consultation with relevant stakeholders. Relevant stakeholder requirements are determined for recording of	Multiple formal and informal efforts are undertaken to understand stakeholder needs and expectations which are reflected in the decision-making framework.	2.5	1.9

ISO 55001 Domain (SAM Domain)	Maturity Level 3 per Standard	UMS Assessment of THESL	THESL Maturity	Comparator Avg. Maturity
	information relevant for AM, and for their reporting internally and externally.			
4.3 Determining the scope of the AM system (Operating Model)	The scope of the asset management system is clearly documented in terms of its boundaries, applicability, interfaces with other management systems and the asset portfolio covered. It is also aligned with AM Policy and Strategy (SAMP).	The scope of THESL AM system and its outputs enable the delivery of the organizational objectives. Overall AM system documentation could be improved.	1.8	1.6
5.1 Leadership and Commitment (Operating Model)	Top management ensures that the AM Policy, SAMP, and Objectives are in place and consistent with organizational objectives. The AM system is fully integrated with the organization's business processes. The approach used for managing AM related risk is aligned with the organization's risk management approach.	Asset management is integrated with the DSP planning process. A corporate risk matrix and tolerance levels have been established to provide a consistent basis for managing risk.	2.0	1.6
5.3 Organizational Roles and Responsibilities (Operating Model)	Top management has assigned responsibility and authority for: i) establishment and update of the SAMP, AM objectives and AM plans; ii) ensuring the adequacy, suitability and effectiveness of the AM system in delivering the strategy and conforming to ISO 55001; and iii) reporting on the performance of the AM system.	Roles and responsibilities for asset management (and the DSP) have been clearly defined.	2.0	1.4
10.3 Improvement (Operating Model)	The organization can demonstrate that the suitability, adequacy and effectiveness of its AM system is being continually improved through its processes for monitoring and evaluation, reviews by top management, and the existence of AM objectives and actions designed to improve the system.	Performance of the DSP in terms of results are tracked to both ensure conformity with AM strategies and programs and identify opportunities for improving execution efficiency and effectiveness.	2.0	1.7

The Processes domain assesses the extent to which the asset management system aligns with ISO 55001 standards for good asset management in terms of the consistency of risk analysis methodology and investment planning, and linking it to asset management policy and corporate/business area strategy. It also assesses the extent to which investments are identified, prioritized and optimized based on overall value, resources, and risk; as well as how asset management plans, processes and procedures are factored into the planning and execution of capital projects and O&M programs. Finally, it assesses how strategy is aligned with action through use on line-of-sight measures.

Across the sub-domains which make up this domain, UMS scored THESL as an average 2.1 maturity, while the comparator group average was 1.6. The maturity level of individual comparators (averaged across the sub-domains) ranged from 1.1 to 2.6.



THESL's scores in the five ISO 55001 domains which make up this aggregated score range from 2.0 to 2.2.

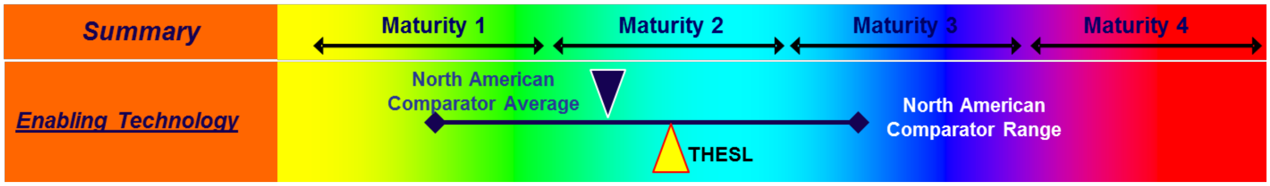
As Table IV-2 below demonstrates, THESL's asset management maturity exceeds the comparator group average maturity in all the sub-domain areas that make up the Processes domain.

Table IV-2: Comparison of THESL against Comparators (Processes)

ISO 55001 Domain (SAM Domain)	Maturity Level 3 per Standard	UMS Assessment of THESL	THESL Maturity	Comparator Avg. Maturity
6.1 Actions to Address Risks and Opportunities (Processes)	Processes and measures are in place to assure that the desired outcomes of the AM system are achieved and undesired effects are mitigated. Internal and external context and stakeholder requirements are considered in determining the risks and opportunities. The organization monitors the effectiveness of actions and processes for addressing the risks and opportunities, and can demonstrate how continual improvement is achieved through risk and opportunity management.	Risk assessment is carried out across multiple dimensions and at multiple points in asset lifecycle analysis. Opportunities are identified both internally and externally through communication with stakeholders. Risk and performance are monitored.	2.2	1.8
6.2 Asset Management Objectives and Planning (Processes)	The organization has documented AM objectives to align with and enable achievement of organizational objectives and AM policy. It considers stakeholder and other requirements in establishing AM objectives. It effectively communicates its AM objectives with those responsible for achieving them. The AM objectives are measurable, monitored, reviewed and updated. It has established and documented its planning processes, methods and decision criteria to achieve objectives.	There is a clear link between asset management objectives and the DSP programs. AM processes are in alignment with industry standard practice and in many cases exceed them.	2.0	1.7
7.1 Resources (Processes)	The organization can demonstrate that it has evaluated and provided adequate resources to establish, maintain and improve the asset management system.	A defined process and responsible group exist to determine the resources needed, including the division of work and use of external resources.	2.2	1.7
8.1 Operational Planning and Control (Processes)	Operational planning and delivery processes are being controlled in accordance with the specified criteria. Documented evidence provides assurance that processes have been carried out as planned. Risks associated with delivery activities are being managed.	Program Management oversees planning and control processes to ensure execution of the DSP, including risk management.	2.0	1.5
9.1 Monitoring, Measurement, Analysis and Evaluation (Processes)	The organization can demonstrate that it has established what needs to be monitored / measured so it can determine whether it achieves the intended outcomes of its AM system.	A performance management framework exists which links directly to strategic objectives and outcomes are compared to targets. A formal process exists for monitoring the asset management system to ensure it is meeting objectives.	2.2	1.3

The Enabling Technology domain assesses the extent to which the asset management system aligns with ISO 55001 standards for good asset management in terms of whether the asset management information management architecture and processes (for systems and data) in place are adequate to support asset-related decisions.

In this domain, UMS scored THESL as a 2.0 maturity, while the comparator group average was 1.7. The maturity level of individual comparators ranged from 1.0 to 2.8.



As Table IV-3 below demonstrates, THESL's asset management maturity exceeds the comparator group average maturity in the one sub-domain area that makes up the Enabling Technology domain.

Table IV-3: Comparison of THESL against Comparators (Enabling Technology

ISO 55001 Domain (SAM Domain)	Maturity Level 3 per Standard	UMS Assessment of THESL	THESL Maturity	Comparator Avg. Maturity
7.5 Information Requirements (Enabling Technology)	All information identified as required for asset management purposes is defined, along with the sources, quality assurance requirements and processes to manage the information. The information is traceable and consistent, including between financial and non-financial information.	THESL has identified the information needed to support development of the DSP and has implemented appropriate technology to use data to support decision-making	2.0	1.7

Appendix A – UMS Group Qualifications

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

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

UMS Group has been a leading provider of asset management services to utilities for over 25 years. It published its first industry report on this topic – the "International Strategic Asset Management Report" in 1992 after conducting a worldwide search for best practices in utility asset management. In the decades since, UMS has developed and continually adapted its methodologies to align them with emerging industry standards; while retaining and refining its proprietary tools and delivery systems.

In recognition of this industry profile, in 2007 UMS Group was invited to participate in the review and update of PAS 55 (Publicly Available Specification 55), the British Standards Institute's definitive specification for Strategic Asset Management processes, practices and organization elements. In August 2010, UMS Group, as one of the first 11 firms so named, was appointed an Endorsed Assessor by the Institute of Asset Management (IAM). The Endorsed Assessor designation followed a rigorous IAM review of the expertise, practices, tools and techniques which UMS Group applies to asset management compliance assessments. UMS has since been appointed both an Endorsed Assessor and an Endorsed Trainer for ISO 55001.

In assisting its clients in meeting the relevant aspects of the international standard, ISO 55000 and the former UK based standard, PAS 55, UMS provides added assurance that they have all the programmatic elements in place to manage their assets, and importantly, to manage all known and implied risks, thus creating superior lifecycle value from their owned and/or operated asset base. In this way, UMS bridges the gap between theoretical knowledge and practical application.

UMS Group also has extensive experience in leading and facilitating major strategic asset management transformations – perhaps more than any other global consultancy dedicated to the utility industry. The major strategic asset management transformations facilitated by UMS Group for 24 separate major clients are credited with achieving significant cost reductions/productivity improvements, process efficiency and effectiveness improvements, system reliability and customer satisfaction improvements and OpEx and CapEx optimization. In addition, this practice competency has given rise to a number of asset management decision support tools.

In 2009, UMS Group created an international consortium of electric transmission companies focused on improving the effectiveness of their Asset Management function. The International Transmission Asset Management Study (ITAMS) provides participants (currently 14 global utilities) with an assessment of their Asset Management Operating Model, Processes, Competences, and Enabling Technology against both their peers and the ISO 55001 standard. It also provides a forum for discussing asset management best practices and a network of contacts for continual sharing and learning.

Apart from these credentials, UMS has accomplished similar projects with clients in various markets around the world. The following table (A-1) summarizes the successful completion of relevant, recent North American projects.

Table A-1: Recent UMS Group North American Asset Management Engagements

Client / Project	Relevant Analyses
Avista Utilities	• Asset Management Maturity Assessment • Asset Management Business Case Development
Nova Scotia Power	• Asset Management Maturity Assessment • Asset Management Operating Model
Manitoba Hydro	• Asset Management Maturity Assessment
Southern California Edison	• Asset Management Maturity Assessment • Asset Management Gap Closure Implementation Plan • Economic Model Development
Tennessee Valley Authority	• Asset Management Maturity Assessment • Asset Management Transformation
PSE&G and PSEG LI	• Asset Management Maturity Assessment • Asset Management Operating Model Development
Lansing Board of Water & Light	• Asset Management Maturity Assessment • Asset Management Transformation
AES	• Asset Management Maturity Assessment • Asset Management Plan Development
PG&E	• Asset Management Plan Development
Baltimore Gas & Electric	• Economic Model Development
Portland General Electric	• Portfolio Optimization Process and Tool
Dominion Resources	• Portfolio Optimization Process and Tool

Experience Summary of Steven J. Morris

Mr. Morris is a Principal of UMS Group. He has 30 years of consulting and management experience with the last 23 years spent in the electric and gas utility industries. He has significant expertise in asset management, performance management, strategic planning, financial analysis, and benchmarking and has written/edited dozens of analytical reports on utility industry topics.

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

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

Highlights of Experience

Led an Asset Management Gap Assessment for a Western U.S. vertically integrated electric and gas utility. Assessed Generation, T&D, Facilities, and IT business units' asset management maturity versus the IAM Maturity Model. Identified alternative Delivery Models to close gaps and developed Business Cases for each model. Identified Alternative Approaches for asset management Operating Models and developed an Implementation Roadmap for closing gaps and implementing the new Operating Model.

Led an Asset Management Gap Assessment for a Canadian vertically integrated electric utility. Assessed Generation, T&D, Facilities, Vegetation Management, and Vehicle Fleet business units' asset management maturity versus the IAM Maturity Model. Developed recommendations for combining business unit asset management functions into an Enterprise Asset Management group. Facilitated site visits for key executives to other North American electric utilities to discuss best practice asset management tools, processes, and techniques.

Led a multi-year Asset Management Transformation for the Transmission Business Unit of a large Southern, multi-state electric utility. Project required creation of an Asset Management organization and development and implementation of all capabilities needed to meet ISO 55001 competence requirements. Specific deliverables included AM Policy, AM Vision, Strategic Asset Management Plan, Asset Risk Assessments, Asset Management Plans, AM Training Program/Material, Economic Lifecycle Models, Data Architecture, and Performance Management Framework.

Led an ISO 55001 Asset Management Gap Assessment for a Canadian Crown Corporation Electric Utility. Performed a corporate-level assessment and individual assessment for the Generation, Transmission, and Distribution business units. Identified gaps and developed prioritized recommendations for closing the gaps. Performed a Work Shop for Executive Leadership to educate them on asset management, discuss the recommendations from the assessment, and review options for organizational structure of asset management.

Led an Asset Management Gap Assessment project for a large Northeastern combination (gas & electric) utility. Review all aspects of current asset management practices against the ISO 55000 standard in order to identify gaps in processes, practices, data, technology, organization, and competencies. For gaps identified, assessed cost, difficulty, and impact of implementation, and created a roadmap structured around designing the needed changes, implementing the changes and working the new processes, and becoming excellent at asset management.

Led an ISO 55000 AM gap assessment for a West Coast electric utility's Generation business unit. Performed an assessment at both the business unit and plant level identifying both gaps and differences in practices. Following completion of the Gap Assessment, led a significant number of Business Unit staff through a 2-day workshop to familiarize them with AM concepts and link them to the findings of the gap assessment. Led the development of a detailed implementation plan to execute a complete Asset Management Transformation for the organization. This plan included identifying all tasks for the 11 work streams needed to close the AM gaps, resource loading those tasks, developing a detailed project scheduled for those tasks, and costing out the tasks. Deliverables included development of an Excel model which calculated time and cost trade-offs between use of internal and external resources at the work stream level for each asset class. End result was a 9000 line item Project plan with a 3 ½ year time frame and 50,000 man-hours of work identified.

Led a project to develop and implement an economic modeling tool and process to support a Canadian Gas utility's natural gas distribution and storage assets. Developed failure curves, identified degradation factors, and developed AHI formulations for 33 asset sub-classes. Developed economic model to link AHI, failure probability, risk, consequence, and intervention costs into an analysis of optimal life cycle replacement. Defined processes for implementing, operating, and updating overall framework and methodology for ongoing use in rate cases development, capital planning, and asset management decision-making.

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

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

Lead an industry forum, the Substation Construction, Maintenance, and Asset Management Best Practice Collaborative, which comprises approximately 20 North American electric utilities who conduct an annual study and share best practices at an annual conference. Now in its 6th year, Mr. Morris created the initial program and has been Program Director since its inception in 2013. Facilitates meetings with the Steering Group to determine annual program content. Oversees design and administration of study, development of study report, conference agenda, and execution of the conference.

Recent Publications/Presentations

- The Development of a Proactive and Predictive Integrity Management Model, World Gas Conference, Washington, DC, June 25-29, 2018

- ISO 55000 Certification Panel, WEI Operations Conference, Phoenix, AZ, April 25-27, 2018
- Real World Experience in Developing Asset Management Plans, CEATI Strategic Asset Management Conference, Vancouver BC, November 1-2, 2017

Power System Engineering, Inc.

Full-service consultants

Standards Review – 2018 Update

Prepared for:

Toronto Hydro Electric System Limited

July 31, 2018

Prepared by:

Power System Engineering, Inc.

Contact: Erik S. Sonju

sonjue@powersystem.org

Direct: 608-268-3501

Mobile: 608-695-8414

Fax: 608-222-9378

1532 W. Broadway
Madison, WI 53713

www.powersystem.org

Confidential and Proprietary

July 31, 2018

Toronto Hydro Electric System Ltd.
Ms. Emma Halilovic
500 Commissioners Street
Toronto, Ontario
Canada

Subject: Standards Review – 2018 Update

Dear Emma:

I am pleased to present the enclosed Standards Review - 2018 Update report for Toronto Hydro Electric System Limited's consideration. The report reflects our review process as well as our findings.

Please do not hesitate to contact me with questions.

Respectively submitted,

Erik S. Sonju

Erik S. Sonju

Table of Contents

1 Introduction

1.1 Background and Purpose

Toronto Hydro Electric System Limited ("THESL") is the largest municipal electrical distribution company in Canada, serving approximately 766,000 customers in the City of Toronto. THESL is the result of six different utilities that amalgamated on January 1, 1998. This amalgamation nearly tripled Toronto Hydro's customer base at the time. Following the amalgamation, THESL initiated the process of integrating various engineering and construction standards, practices, and processes (herein referenced as "Standards") of the different utilities. The result was a single comprehensive set of Standards with the focus on the principles of safety, reliability, and efficiency, while also working within the framework of industry best practices.

In 2010, THESL re-structured its Standards Department with the direction to establish, refine, and maintain the company's Standards that pertain to the design, materials, construction, and maintenance of the electric distribution system infrastructure. This undertaking resulted in three years of dedication by the Standards Department to review and renovate all major Standards used by THESL's engineering and operations personnel. In 2013, before fully deploying the results of their efforts, the Standards Department determined value in hiring an outside independent party to review what had been assembled as a method to ensure the Standards met established industry practices and promoted the previously mentioned principles. Subsequently, THESL retained the services of Power System Engineering, Inc. ("PSE") to conduct this review.

In January 2014, PSE provided THESL with a report summarizing the result of the independent third-party review ("2014 Independent Review"). The review process conducted by PSE consisted of interviews with key individuals in the Standards Department and examination of Standards that were to be deployed across the Company. The focus throughout the review process was to determine if THESL's Standards advocated the principles of safety, reliability, and efficiency, as well as followed industry best practices.

Following the 2014 Independent Review, the THESL Standards Department continued to maintain their Standards through a managed revision process. In March 2018 THESL retained the services of PSE to conduct an update to the 2014 Independent Review, with a focus on Standard revisions that occurred between January 2014 and March 2018. The purpose of this report is to summarize PSE's review of the revised standards ("2018 Independent Review").

1.2 Review Scope

There are three major Standard categories that heavily influence the design, construction and maintenance of THESL's electric distribution infrastructure. These categories include design and construction, major material specifications, and procedural processes. Within the design and construction category are THESL's Standard Design Practices and Distribution Construction Standards. The material specifications category is controlled through THESL's Equipment Technical Specifications. Finally, THESL's Major, Non-Major and Ancillary Equipment

Approval Process sets the structure of internal Procedural Processes. Each Standard has a specific focus, yet each of the individual Standards complement each other, creating a comprehensive framework for all design, construction and maintenance activities associated with the THESL's electric distribution infrastructure.

Design & Construction

- Standard Design Practices
- Distribution Construction Standards

Material Specifications

- Equipment Technical Specifications

Procedural Processes

- Major Equipment Approval Process
- Non-Major / Ancillary Equipment (Material) Approval Process

1.3 Approach

As previously indicated, the purpose of this 2018 Independent Review is to address Standard revisions that occurred between January 2014 and March 2018. As such, the volume and type of information reviewed was extensively less than that covered in the 2014 Independent Review. Therefore, the review process was conducted by two PSE industry experts who specialize in electric distribution systems as compared to a larger team.

The following industry experts participated in this review include:

- **Erik S. Sonju**
  Erik earned a BS degree in Electrical Engineering from North Dakota State University at Fargo, North Dakota with an emphasis in power systems. He has over 20 years of experience in the power industry, with the majority of those years providing professional engineering consulting services to electric utilities and private industry throughout the United States and Canada with an emphasis in planning and design. He regularly presents at industry conferences on a variety of topics. Erik is a licensed Professional Engineer in 20 states and in the Canadian province of Saskatchewan.

- **Douglas R. Joens**
  Doug earned a BS degree in Electrical Engineering from South Dakota State University at Brookings, South Dakota. He has over 40 years of experience in electric utility distribution system planning, substation and line design, system protection and operation, and work order inspections. He has also participated in large power contract negotiations, and has managed projects related to overcurrent protection and on-site generator installations. Doug is a licensed professional engineer in Minnesota and Alaska.

The review of the revised Standards was divided amongst the abovementioned individuals. Following their review, they jointly discussed their findings for developing this report. The review was conducted at a high level with similar intentions used in the 2014 Independent Review.

In addition to the review, specific Standard revisions questions that arose during the review were submitted to THESL.

2 Design & Construction

2.1 Standard Design Practices

The Standard Design Practices (SDP) document confers THESL's Standards as they relate to the design of the electric distribution system.

PSE specifically reviewed Revision 3 of the SPD that was approved on February 8, 2018. The SDP Revision 3 contained approximately 125 modifications as compared to SDP Revision 2 with the purpose of alignment amongst other standards and processes, continuous improvement, third party requirements, and general engineering & operations considerations.

Overall, PSE found the SDP to be aligned with others in the industry. Only a few minor items were noted. These items are summarized below along with THESL's comments.

<u>LED Luminaires</u>

PSE noted that the lighting section of the SDP did not mention the application of LED luminaires while they were included in the material technical specification.

THESL verified that they have developed technical specifications and approved an LED luminaire, which was installed at several LED pilot sites in 2015. THESL further verified that although LED luminaries have been installed in a couple of projects at the City's request, the City has not given official direction to implement LED lighting on a large scale. Therefore, the currently approved street lighting standards include High Pressure Sodium (HPS) and Metal Halide (MH).

<u>Direct Buried Conduit</u>

PSE noted that the application of direct buried conduit was not prominent in the SDP.

THESL verified that concrete encased ducts are used if: 1) ducts are carrying primary cables (750 V or more), 2) ducts are under roadway or driveway, 3) ducts have 90 degree bends, 4) the number of ducts are more than 8. Direct buried conduit is used if these categories do not apply. Additionally, THESL verified that in certain instances (ex. replacement of primary direct buried cables within a townhome complex with various grade levels/retaining walls and mature trees), direct buried conduits are used. THESL also indicated that they are currently co-funding a CEATI initiative to evaluate direct buried duct vs. concrete encased duct which is anticipated to be completed in September 2018.

Voltage Rating of Cutouts

PSE noted the use of 25kV cutouts, rather than 15kV cutouts, on the 13.8kV system.

THESL verified that they have found benefit, from a material inventory standpoint in using 25kV cutouts on both their 13.8kV and 27.6kV systems.

Secondary Voltage Drop

PSE noted the maximum allowable voltage drop on the secondary bus and service cables as it relates to voltage variation limits.

THESL clarified that the maximum allowed voltage drop (in terms of Volts) shall be less than the voltage drop calculated from voltage variation limit levels.

Unmetered Connections

PSE noted a misunderstanding of unmetered connection replacements.

THESL clarified that rather than unmetered connections, it is the service cables that may be replaced if determined from field conditions. THESL verified that this clarification will be made in Revision 4 of the SDP.

Conductor Replacement Based on Splices

PSE noted that bare primary conductors shall be re-used when it does not have more than two splices per span.

THESL confirmed this requirement.

PSE recommends that THESL considers splices within multiple adjacent spans when considering the replacement or re-use of a conductor.

Of the items noted above, THESL could provide PSE with corresponding clarifications of, or justifications for, their standard design practices. For example, THESL has an action plan to further assess their practices around the application of direct buried conduit following the completion of a third-party study being conducted by CEATI. Another example is the application of LED street lighting which is pending direction from the City of Toronto. These examples, along with clarifications provided by THESL, gave PSE a level of satisfaction that the SDPs are well thought through and are backed by sound engineering analysis and decision making.

2.2 Distribution Construction Standards

The Distribution Construction Standards (DCS) provide Standards applicable to construction of the THESL electric distribution system.
PSE only reviewed construction standards that have been revised since the 2014 Independent Review. Since this review, THESL made 12 revision releases (Standards Revision #42 through

#53). A copy of these revision releases and the corresponding DCS revisions are provided as an Appendix to this report.

Overall, PSE found the DCS revisions to be aligned with others in the industry. Only a few minor items were noted. These items are summarized below along with THESL's comments.

> <u>Replacement of Design Guides (DCS 7-3100 through 7-3400)</u>
>
> PSE noted the removal of certain design guides that are used for determining certain factors such as guying.
>
> THESL verified that all guying design analysis is carried out by using a pole loading analysis tool available to designers or a non-linear pole loading analysis software program. These tools have made DCS 7-3100 through 7-3400 obsolete.
>
> <u>Three-Bolt Clamps (DCS 7-5300)</u>
>
> PSE noted the application of 3-bolt clamps used on guy wires.
>
> THESL verified the use of pre-formed guy grips on all connections to a guy wire with the exception at the lower connection point. A 3-bolt clamp is used at the lower connection point to allow for adjustment of the guy tension.
>
> <u>Elbow Arrestor on Radial Fed Padmount Transformers (DCS 7-5300)</u>
>
> PSE noted the absence of elbow arresters on radial fed padmount transformers.
>
> THESL verified that they do not apply elbow arresters on radial fed padmount transformers.
>
> PSE recommends the application of elbow arresters at these locations if lightning induced failures have been experienced on THESL's underground system.

Similar to their SDPs, THESL could provide PSE with corresponding justifications for their distribution construction standards. For example, THESL has implemented computer applications to provide a more efficient and thorough assessment of pole loadings that has allowed them to remove certain design guides from their standards. Also, as another example, THESL has chosen to continue the use of three-bolt clamps on guy wires for benefiting line personnel when adjusting wire tensions. These examples, gave PSE a level of satisfaction that the DCSs are well thought through and are backed by sound engineering and operations analysis and decision making.

3 Material Specifications

3.1 Equipment Technical Specifications

Equipment Technical Specifications (ETS) are used for specifying and purchasing equipment to be used on the THESL system. PSE reviewed ETS that were added or modified since the 2014 Independent Review. These specifications include:

Major Equipment Technical Specifications

- Single-Phase Submersible Distribution Transformers (KNAN Type)
- Three-Phase Submersible Distribution Transformers
- Single-Phase Pole-Mounted Distribution Transformers
- Single-Phase Submersible Distribution Transformers (ONAN Type)
- Distribution Polymer Insulators
- Pad-Mounted Three-Phase Live Front Distribution Transformers (ONAN Type)
- Pad-Mounted Low Profile Single-Phase Distribution Transformers with Internal and Loadbreak Switches (ONAN and KNAN Types)
- Pad-Mounted Three-Phase Distribution Transformers with Internal and Loadbreak Switches (ONAN)
- Distribution Composite Pole
- Treated Western Red Cedar Poles
- 3 MVA to 12 MVA Outdoor Station Power Transformer
- Tree Proof Cable
- Neutral Supported and Field Lashed Secondary Cable Rated 600 Volt
- Polyethylene Covered Weatherproof Line Wire
- Transformer Drop Wire
- Paper Insulated Lead Covered Polyethylene Jacketed Power Cable Rated 5 to 30 kV
- Single Conductor and Triplexed Tree Retardant Crosslinked Polyethylene Insulated Power Cable 15 to 30 kV
- Underground Secondary Cable Rated 600 Volt

Overall, PSE found the reviewed ETS to be aligned with others in the industry. Only one minor item was noted. This item is summarized below along with THESL's comments.

Non-Application of EPR Cable

PSE noted, of the technical specifications reviewed, and the SDP revisions made, the application of EPR was not present; leading to the question if THESL only uses TRXLPE for non-PILC cable.

THESL verified their experience with TRXLPE cable extends over 30 years. One of the advantages of TRXLPE is that the compounds are not proprietary in nature (as they are with EPR), which allows for direct comparison of different manufacturer's TRXLPE cables.

THESL further verified that in 2017, they developed a performance based technical specification of reduced wall thickness design EPR cables that will replace 13.8 kV PILC cables installed in 3.5" ducts are smaller; where TRXLPE cable cannot be applied. At the time of this report, 500 kcmil Cu 15 kV EPR cable has been approved and revisions to the applicable Standards are in progress. Existing cable accessories used by THESL are compatible with the approved EPR cable.

4 Procedural Processes

4.1 Major, Non-Major and Ancillary Equipment Approval

THESL has two approval processes for equipment. One is the approval process for major equipment while the other is for non-major equipment and ancillary.

In all categories, THESL's equipment approval process provides a reasonable degree of assurance that products applied to the system are safe and reliable. For instance, items that fall under the major equipment category must adhere to THESL technical specifications. These specifications, that are all reviewed and approved by a THESL professional engineer, include industry standards and qualifying tests amongst other elements. Non-major equipment must either be pre-approved by a recognized certification organization, or have a proven historical record of successful use in the industry. Ancillary Equipment may be approved via:

1. Certification against Industry Standards and/or Field Evaluation Agency or;
2. Electrical Safety Code (ESC) Rule 2-024.

Since the 2014 Independent Review THESL modified the process slightly to include a Product Change Committee (PCC) to receive all major, non-major and ancillary equipment requests before going through the previously established approval process. The PCC must approve the initial equipment request and assign a task for technical evaluation to standards and materials before the process can proceed. Additionally, the PCC must accept the technical evaluation results provided by standards and materials before the equipment is approved for use.

This approval process is in alignment with the technical guidelines for the approval of electrical equipment as outline by the Electrical Safety Authority (Ontario Regulation 22/04).

5 Conclusion

THESL's revised Standards were found by PSE to be thorough, well documented, and consistent with what is seen in the industry. The results of PSE's review and evaluation produced only minor questions and comments, which have been discussed with the THESL staff. Of these questions and comments, THESL was either able to sufficiently provide supporting justification to uphold a specific Standard or set into action further review for change.

It is also worth noting that this is an update to a standard review conducted by PSE in 2014 and general observations previously identified continue to exist today. These observations include:

- The Standards Department at THESL consists of professionals who have previous experience with outside entities, which has brought the Department various levels and types of expertise. The Department also consists of professionals who have a long-term relationship and understanding of the downtown Toronto electric distribution system. This blend of outside experience and internal knowledge is personified by a diverse group of professionals with the breadth and depth of knowledge that is needed by the trustees of the Company's Standards.

- The Department's engineers also continue to gain industry knowledge by engaging and participating in various associations, forums and initiatives. One example of this is THESL's participation in the Institute of Electrical and Electronic Engineers (IEEE) and Canadian Standards Association (CSA) working groups. IEEE is considered to be the world's largest professional association that serves technical professionals globally. IEEE has a Standards Association that offers a library of current standards in the electrical industry. THESL is a subscriber to IEEE Explore, which provides web access to all IEEE standards. The Canadian Standards Association is a non-profit standards organization that develops industry standards across 57 areas of specialization, with electrical standards being one area of expertise. CSA develops, updates, and sells standards through their Standards Store. THESL has a significant library of such CSA Standards. THESL is also currently engaged with CSA industry initiatives and committees, currently serving on the Technical Subcommittee for Transformers. By participating in both IEEE and CSA initiatives and activities, THESL is actively and continually exposed to the development of standards both locally and globally.

- THESL is also actively involved with the Utilities Standards Forum (USF) as well as an Inter-Utility Forum. The USF is an organization representing approximately 50 Ontario electric distribution companies. Its goal is to collaboratively define standards for its members and reduce duplication of efforts. The USF has developed design standards for electricity distribution that meet the requirements of Ontario Regulation 22/04 under the Electricity Act of 1998. The Inter-Utility Forum is made up of a small group of utilities including Alectra, Veridian Connections, Peterborough Utilities Group, and London Hydro. THESL's involvement in both forums has and will continue to help cross-pollinate concepts and ideas with other Ontario-based utilities.

- THESL is also a member of the Centre of Energy Advancement through Technological Innovation (CEATI International). CEATI International is a user-driven organization that provides technology solutions and training to electrical utility participants. CEATI International is driven by over 120 organizations, including electric utilities, governmental agencies, and research-based organizations. THESL can benefit from this membership by looking to CEATI International as a research and development aid that will help keep personnel current with new technologies, as well as solidify their understanding of existing technical concepts. Information gained from CEATI International's efforts and reports can be applied to new and revised THESL Standards.

6 Appendix

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #42

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
RORY CALHOUN	00-0001		TABLE OF CONTENTS	0	Revised	- tabs 22 and 33 have been changed to read (For Future Use)
James Daniel	03-2000		Overhead - Minimum Clearances Standard Attachment Points	3	Revised	- Added Trolley TTC cable attachment - Updated pictorially
Tarek Turk	05-1220		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Semi-Triangular Circuit Side Mounted Angles 0 to 15 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1240		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Single Circuit Vertical Configuration Angles 0 to 15 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1260		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase In-Line Rolled Configuration Angles 0 to 3 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1320		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Suspension Vertical Configuration Angles 16 to 45 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1340		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Vertical Configuration Angles 0 to 45 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1360		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Semi-Triangular Circuit Angles 16 to 45 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1380		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Suspension Angles 46 to 90 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1400		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Dead-End Vertical Configuration Angles 61 to 90 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1480		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Dead-End Vertical Configuration	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1600		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Dead-End or Transition Between Bare and Treeproof Vertical Configuration	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1740		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Circuit Vertical Angles 0 to 15 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1760		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Circuit Vertical Angles 16 to 45 Degrees	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1840		4.16 to 27.6 kV Treeproof and Bare Primary Double 3-Phase Vertical Configuration 1 Tangent Circuit and 1 Dead-end Circuit	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #42

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
Tarek Turk	05-1860		4.16 to 27.6 kV Treeproof and Bare Primary Double 3-Phase Dead-end Vertical Configuration	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-1880		4.16 to 27.6 kV Treeproof and Bare Primary Double 3-Phase Double Dead-end or Transition Between Bare and Treeproof Vertical Configuration	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-2040		4.16 to 27.6 kV Treeproof and Bare Primary 1-Phase Run-Off From 3-Phase Vertical	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-2060		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Vertical Run-Off From 3-Phase Vertical Near Side	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-2080		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Vertical Run-Off From 3-Phase Vertical Far Side	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-2280		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Vertical Run-Off From Double 3-Phase Vertical Dead-end Circuit	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Tarek Turk	05-2400		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Circuit Run-Offs From 3-Phase Double Circuit Dead-end Vertical Configuration	5	Revised	Vertical seperation clearances reduced to 50" for 27.6 kV and to 40" for 13.8 kV 4.16 kV
Emma Halilovic	07-0000		INDEX OF STANDARDS	7	REVISED	-Title change 7.6 page 3 for STD. 07-5320
Emma Halilovic	07-5320		SPAN & DOWN GUYS - TWO ON CONCRETE, WOOD OR STEEL POLE	7	Revised	Change to add Steel Pole and title change
Emma Halilovic	07-5370		SPAN AND STRUT GUYS - TWO	7	Revised	BOM title change
John Hecimovic	12-3350		Primary Service Risers Fused 1-Phase 4.16 kV to 27.6 kV GRD. Y	12	Revised	Bom change and added 2 notes
John Hecimovic	12-3550		Primary Service Risers Fused 3-Phase 4.16 kV to 27.6 kV GRD. Y	12	Revised	Bom change and added 2 notes
James Daniel	15-3800		Secondary Underground Services Up To 200 A Temporary Service Installation	15	Revised	- Revised min. depth of cover - Replaced PVC with schedule 40 - Updated reducer pictorially
Ingrid Eleosida	18-3250		Cable Guard For Direct Buried Cable	18	Revised	Bom legend C and D
James Daniel	23-1110		Overhead System - Pole Attachments Temporary Banner and Flower Basket Size and Clearances	23	Revised	- Revised basket location in note 2

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #42

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
James Daniel	23-1120		Overhead System - Pole Attachments Temporary Flowwer Baskets on Ornamental Streetlight Pole	23	Revised	- Revised basket location in note 3 - Added note 5
James Daniel	23-1130		Overhead System - Pole Attachments temporrary Seasonal Lighted Decoration Size and Clearances	23	Revised	- Revised attachment location in note 2
John Hecimovic	24-1300		OVERHEAD FUSING	24	Revised	1 Changes in notes and 2 changes in legend
James Daniel	30-4210		COBRA HEAD LUMINAIRE ON ALUMINUM POLE 28',35',BASE MOUNTED & 37' DIRECT BURIED	30	REVISED	BOM #2 DISCRIPTION REVISED
James Daniel	31-1120		CONDUITS CONCRETE ENCASED & DIRECT BURIED DUCTS	31	Revised	- Converted 11" x 17" drawing to 8-1/2" x 11" - Added 15 duct structure - Revised notes
James Daniel	31-1170		CONDUITS DIVERTING DUCT BANK	31	Revised	- Converted 11" x 17" drawing to 8-1/2" x 11"
James Daniel	31-1220		CONDUITS INSTALLATION OF DUCTS FROM POLES	31	Revised	- Converted 11" x 17" drawing to 8-1/2" x 11" - Replaced PVC with schedule 40 bends - Revised min. depth of cover - Deleted note 5 and 7
James Daniel	31-1260		CONDUITS FIBERGLASS REINFORCED EPOXY (FRE) CONDUITS FOR BRIDGE CROSSINGS (TYP.)	31	Revised	- Added imperial dimensions - Updated title - Added FRE duct annotation
James Daniel	31-1370		SUPPORT OF U.G. CONDUIT CROSSING EXCAVATIONS	31	Revised	- Converted 11" x 17" drawing to 8-1/2" x 11"
James Daniel	31-4015		Padmounts Clearance Zone	31	Revised	- Added 1-Phase and 3-Phase transformer - Updated PME/PMH switchgear - Revised notes - Revised title
James Daniel	31-4080		Padmounts Guard Posts (Bollards)	31	Revised	- Added 1-Phase and 3-Phase transformer - Updated pme/pmh switchgear - Revised note 13
James Daniel	31-6000		Customer-Owned Structures Design and Construction Requirements	31	Revised	- Revised sections 1.0, 2.0, 3.0 and 4.0
James Daniel	31-6010		Customer-Owned Structures Vault Design Requirements	31	Revised	- Revised (previously labelled) sections 1.0, 2.0, 3.0, 4.0, 5.0, and 6.0 - Added vault access requirements section

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #42

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
James Daniel	31-6020		Customer-Owned Structures Above Grade - Walk-In Vault	31	Revised	- Revised detail 'B' - Updated notes and added note 5
James Daniel	31-6030		Customer-Owned Structures Below-Grade Walk-In Vault	31	Revised	- Updated vault table - Revised detail 'B' - Updated notes and added note 5
James Daniel	31-6035		Customer-Owned Structures Above-Grade Walk-In or Below Grade Switching Vault	31	Revised	- Revised detail 'B' - Updated notes and added note 7, 8, and 9
James Daniel	31-6040		Customer-Owned Structures Stair and Access Well Detail For Below-Grade Vaults	31	Revised	- Added imperial dimensions - Updated notes
James Daniel	31-6050		Customer-Owned Structures Louver Details For Vent Openings	31	Revised	- Updated notes - Revised detail 'A' - Added reference Std. 31-6060 in annotations
James Daniel	31-6080		Customer-Owned Structures 4.16 kV - 13.8 kV Transformer Vaults	31	Revised	- Revised all vaults - Added note 1 - Updated reference standards
James Daniel	31-8290		Top Sections (Frame and Plates) No Vehicular Traffic 2160 x 1140 x 1980 mm Deep Submersible Vault	31	Revised	- Converted 11" x 17" drawing to 8-1/2" x 11" - Added BOM legend - Updated BOM and notes
James Daniel	31-8330		Aluminum Ladderway Grid	31	Revised	- Updated panel dimension - Updated sections 'C-C' and 'D-D' and details 'C' and 'D'
James Daniel	31-8410		Material Fabrication Caulking of Removable Slabs	31	Revised	- Added BOM - Updated notes - Revised section 'A-A'

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #43

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
John Hecimovic	03-0000		INDEX OF STANDARDS	3	REVISED	NEW STANDARD ADDED
James Daniel	03-2100		OVERHEAD - MINIMUM CLEARANCES CROSSING IN SPAN	3	REVISED	REVISED
James Daniel	03-2250		OVERHEAD - MINIMUM CLEARANCES PARALLELING TRANSMISSION LINES	3	REVISED	COMPLETE STANDARD REVIEW
James Daniel	04-5100		GENERAL INFORMATION CEDAR,CONCRETE,AND STEEL POLES	4	REVISED	LANGUAGE REVISED
Emma Halilovic	05-0010		GENERAL INFORMATION	5	REVISED	ADDED MANUFACTURER RECOMMENDED BOLT TIGHTENING TORQUE FOR LINE POST INSULATORS
Tarek Turk	05-1000		4.16KV TO 27.6KV TREEPROOF AND BARE PRIMARY 1-PHASE	5	REVISED	Revise BOM
Emma Halilovic	05-1820		4.16KV TO 27.6KV TREEPROOF AND BARE PRIMARY 3-PHASE	5	REVISED	ADDED A NOTE
Emma Halilovic	06-1000		SAGS AND TENSION	6	REVISED	ADDED STOCK CODE FOR TENSION METER
Emma Halilovic	07-0000		INDEX OF STANDARDS	7	REVISED	Index of Standards revised due to new standard
Emma Halilovic	07-4250		GUYING INSTALLATION PROCEDURE STRUT	7	NEW	New standard added
Kalyan Sarkar	08-0000		INDEX OF STANDARDS	8	REVISED	New standard added
Kalyan Sarkar	08-3120		OVERHEAD CONNECTORS HAND TAPING SLEEVE	8	NEW	New
John Hecimovic	09-0000		INDEX OF STANDARDS	9	REVISED	Index of Standards revised due to new standard
Emma Halilovic	09-3300		CONNECTIONS CURRENT LIMITING FUSE CONNECTION DETAILS	9	REVISED	REVISED CLF TERMINAL
John Hecimovic	09-9500		PRIMARY DROP LEADS 1-PHASE TRANSFORMERS	9	REVISED	Changed from solid tap to a hot line solution and BOM

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #43

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
John Hecimovic	09-9510		PRIMARY DROP - LEADS 1-PHASE TRANSFORMERS - DEAD-END CONFIGURATION	9	NEW	New
John Hecimovic	09-9550		PRIMARY DROP LEADS 1-PHASE TRANSFORMERS - OVERBUILD AND UNDERBUILD	9	REVISED	Changed from solid tap to a hot line solution and BOM
John Hecimovic	09--9600		PRIMARY LOOP LEADS 3-PHASE TRANSFORMERS	9	REVISED	Changed from solid tap to a hot line solution and BOM
John Hecimovic	09-9610		PRIMARY DROP LEADS 3-PHASE TRANSFORMERS - DEAD-END CONFIGURATION	9	NEW	New
Tarek Turk	10-1300		OVERHEAD SWITCHES	10	REVISED	Revise drawing and BOM
Kalyan Sarkar	11-5400		120 V CONNECTION FOR UNMETERED SERVICES FED FROM OVERHEAD SUPPLY	11	REVISED	Part number change
John Hecimovic	12-0000		INDEX OF STANDARDS	12	REVISED	Index of Standards revised due to new standard
James Daniel	12-1200		RISER INSTALLATION DETAILS - CABLE CAURD OR PIPE	12	REVISED	Updated notes, BOM, pictorial revisions
John Hecimovic	12-3360		Primary Service Risers Fused 1-Phase 13.8 kV to 27.6 kV GRD. Y Above Existing Underbuild	12	NEW	New
John Hecimovic	12-3560		Primary Service Risers Fused 3-Phase 13.8 kV to 27.6 kV GRD. Y Above Existing Underbuild	12	NEW	New
Igor Simonov	13-0000		INDEX OF STANDARDS	13	REVISED	INDEX
Igor Simonov	13-5010		13.8kV NETWORK SYSTEM NETWORK TRANSFORMER VAULTS	13	REVISED	Revision of BOM
Igor Simonov	13-5020		13.8 KV NETWORK SYSTEM STAND ALONE NP	13	REVISED	Updated BOM with new 3 hole fuse
John Hecimovic	13-7200		GRD. Y VAULT - TYPICAL LAYOUT 27.6 Kv	13	REVISED	Changed from NX fusing to MCLF
John Hecimovic	13-7500		3 1-PHASE TRANSFORMER VAULT 27.6 Kv CUSTOMER ROOM WITH SF6 SWITCHGEAR	13	REVISED	Dimentions added

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #43

TORONTO HYDRO

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
John Hecimovic	13-7520		3 1-PHASE TRANSFORMER VAULT 13.8 Kv CUSTOMER ROOM WITH SF6 SWITCHGEAR	13	NEW	New
John Hecimovic	13-7810		UNDERGROUND DISTRIBUTION SWITCHGEAR EQUIVALENT TO PMH-9	13	REVISED	Revise notes and drawing for oriantation of padmount
John Hecimovic	13-7820		UNDERGROUND DISTRIBUTION SWITCHGEAR EQUIVALENT TO PMH-11	13	REVISED	Revise notes and drawing for oriantation of padmount
Kalyan Sarkar	15-2000		SECONDARY UNDERGROUND SERVICES UP TO 100 A INTRODUCTION	15	REVISED	Revise notes
John Hecimovic	15-2100		Secondary Underground Services Up To 100 A Fed From Cable Chamber or Tap Box	15	REVISED	Full Review and Evaluation (NO MU)
Tarek Turk	15-2700		120V CONNECTION FOR UNMETERED SERVICE	15	REVISED	Revised drawing to add ground at customer connection , Revised note 9
Kalyan Sarkar	15-3100		SECONDARY UNDERGROUND SERVICES UP TO 200 A FED FROM CABLE CHAMBER OR TAP BOX	15	REVISED	Revise notes
Kalyan Sarkar	15-4100		SECONDARY UNDERGROUND SERVICES UP TO 200 A FED FROM CABLE CHAMBER OR TAP BOX	15	REVISED	Revise notes
Kalyan Sarkar	16-0000		INDEX OF STANDARDS	16	REVISED	Index of Standards revised due to new standard
Kalyan Sarkar	16-0280		600 V SECONDARY CABLES PHYSICAL CHARACTERISTICS	16	NEW	New
Kalyan Sarkar	16-4580		PRIMARY - INLINE TRANSITION JOINT HAND TAPING METHOD	16	REVISED	Revised dimentions and BOM
Kalyan Sarkar	16-4600		PRIMARY - INLINE TRANSITION JOINT HAND TAPING METHOD	16	NEW	New
Kalyan Sarkar	16-4620		PRIMARY - TRIFURCATING TRANSITION JOINT	16	REVISED	Revised BOM
Kalyan Sarkar	16-5400		SECONDARY - TERMINATIONS	16	REVISED	REVISED BOM
Ingrid Eleosida	18-1000		GENERAL INFORMATION	18	REVISED	Dimensions change, 3/0 grounding for network vault

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #43

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
James Daniel	18-3250		OVERHEAD CABLE GUARD FOR DIRECT BURRIED CABLE	18	REVISED	
John Hecimovic	21-0000		INDEX OF STANDARDS	21	REVISED	Index of Standards revised due to new standard
John Hecimovic	21-1100		GENERAL INFORMATION STENCILING INFORMATION	21	REVISED	Added to BOM
John Hecimovic	21-2110		2 X 3 PHASE POCKET PANNELS	21	NEW	New
John Hecimovic	21-3900		UNDERGROUND STENCILING	21	REVISED	Distributed generation label added
James Daniel	23-1020		OVERHEAD SYSTEM - POLE ATTACHMENTS OVERHEAD 120 V CONNECTION FOR UNMETERED SERVICES	23	REVISED	Revised drawing and BOM
James Daniel	23-1030		UNDERGROUND 120 UNMETERED CONNECTION SERVICE ATTACHED TO TORONTO HYDRO POLES	23	REVISED	BOM REVISED
John Hecimovic	24-1100		OVERHEAD FUSING TRANSFORMERS	24	REVISED	Revised fusing location chart
Igor Simonov	24-2100		UNDERGROUND FUSING NETWORK PROTECTORS	24	REVISED	Revised BOM
James Daniel	30-4100		CONCRETE POLE 25' & 30' WITH UNIVERSAL LUMINAIRE	30	REVISED	Clean up of drawing
James Daniel	30-4290		COMPOSITE POLE 30' WITH UNIVERSAL LUMINAIRE	30	REVISED	Updated dimensions, notes, BOM, pictorial revisions
James Daniel	31-1100		CONDUITS GENERAL INFORMATION	31	REVISED	Full Review and Evaluation
James Daniel	31-2130		CABLE CHAMBERS UNDERPINNING CHANBER STRUCTUAL DETAILS	31	REVISED	Added new note 8
James Daniel	31-2190		Cable Chambers Underpinning Chambers	31	REVISED	Full Review and Evaluation
James Daniel	31-4050		PADMOUNTS THREE PHASE PMH 9/11 SWITCHGEAR 1980mm X 2160mm X 1350mm	31	REVISED	To revise notes

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #43

REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
James Daniel	31-5120		SPLICE VAULT 'D' For 1000 kcmil Primary cables 1625 mm (5'-4") X 2750 mm (9'-0") X 2250 mm (7'-5") Deep	31	REVISED	Full Review and Evaluation
James Daniel	31-5150		Single Unit Transformer Vault 2290 mm (7'-6") X 3650 mm (12'-0") X 3650 mm (12'-0") Head-Room	31	REVISED	Full Review and Evaluation
Tarek Turk	33-1000		GENERAL INFORMATION SK/SKE	33	NEW	New

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #44

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
1	JAMES DANIEL	03-0000		INDEX OF STANDARDS	03	REVISED	NEW AND OBSOLETED STANDARDS
2	JAMES DANIEL	03-2000		OVERHEAD-MINIMUM CLEARANCES STANDARD ATTACHMENT POINT	03	REVISED	NOTE 2 ABCDE CHANGED
3	JOHN HECIMOVIC	03-2050	03-2100	OH MINIMUM CLEARANCES	03	OBSOLETE	SEE STANDARD 03-2100
4	JAMES DANIEL	03-2350		OVERHEAD - MINIMUM CLEARANCES BETWEEN CONDUCTORS AND SWIMMING POOLS	03	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
5	JAMES DANIEL	03-2400		OVERHEAD-MINIMUM CLEARANCES POLES AND PRIVATE FENCES	03	Revised	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
6	JAMES DANIEL	03-2500		OVERHEAD - MINIMUM CLEARANCES BETWEEN CONDUCTRS AND NAVIGABLE WATERWAYS	03	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
7	JAMES DANIEL	03-2600	03-2000	OH MINIMUM CLEARANCES BETWEEN CONDUCTORS AND STREETLIGHT BRACKET	03	OBSOLETE	SEE STANDARD 03-2000
8	JAMES DANIEL	03-2650		OVERHEAD - SECONDARY SERVICE CONNECTION MINIMUM CLEARANCE ABOVE FINISHED GRADE	03	Revised	Updated dimensions, notes, BOM, pictorial revisions
9	JAMES DANIEL	04-5100		GENERAL INFORMATION - CEDAR, CONCRETE, AND STEEL POLES	04	REVISED	DOC
	EMMA HALILOVIC	05-0000		INDEX OF STANDARDS	05	REVISED	DOC
10	EMMA HALILOVIC	05-1360		4.16 TO 27.6 kV TREEPROOF AND BARE PRIMARY 3-PHASE SEMI-TRIANGULAR CIRCUIT ANGLES 16 TO 46 DEGREES	05	REVISED	ADDED OPTION FOR CIRCUIT WITH 2 PHASES IN SUSPENSION AND 1 PHASE IN
11	EMMA HALILOVIC	05-1370		4kV - 27.6kV TREEPROOF AND BARE PRIMARY 3-PHASE SEMI-TRIANGULAR CIRCUIT	05	NEW	NEW STANDARD

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #44

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
12	EMMA HALILOVIC	07-3000		GUYING - GENERAL INFORMATION	07	REVISED	Notes added to 3)
13	EMMA HALILOVIC	07-4240		GUYING INSTALLATION PROCEDURE INSULATOR ROD	07	REVISED	Revised to add double eye link
14	EMMA HALILOVIC	07-5500		SPAN GUY - ONE ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	MUs REQUIRED Revised notes 3 and 5 and figure 1
15	JOHN HECIMOVIC	09-1300		GENERAL INFORMATION INSTALLATION	09	REVISED	NOTE CHANGE
16	JOHN HECIMOVIC	09-8600		3-PHASE CONSTRUCTION 8000/13800 -120/2040-50kV	09	REVISED	CHECK MU's NOTE CHANGE
17	JOHN HECIMOVIC	09-8700		3-PHASE CONSTRUCTION 8000/13800 - 120/208-100 & 167kVA	09	REVISED	CHECK MU's NOTE CHANGE
18	JOHN HECIMOVIC	09-8800		3-PHASE CONSTRUCTION 16000/27600 - 120/208 V - 50kVA	09	REVISED	NOTE CHANGE
19	JOHN HECIMOVIC	09-8900		3-PHASE CONSTRUCTION 16000/27600	09	REVISED	NOTE CHANGE
20	JOHN HECIMOVIC	09-9100		3-PHASE CONSTRUCTION 2400/4160 - 347/600 V WYE 100 & 167kV	09	REVISED	NOTE CHANGE
21	JOHN HECIMOVIC	09-9200		3-PHASE CONSTRUCTION 8000/13800 - 347/600V WYE ALL KVA SIZES	09	REVISED	NOTE CHANGE
22	JOHN HECIMOVIC	09-9300		3-PHASE CONSTRUCTION 16000/13800 - 347/600 V WHY ALL KVA SIZES	09	REVISED	NOTE CHANGE
24	JAMES DANIEL	10-3100		3-PHASE LOAD INTERRUPTER SWITCH	10	NEW	NEW STANDARD

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #44

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
25	EMMA HALILOVIC	10-3700		COMMUNICATION AND CONTROL UNIT (CCU) SCADA AND FEEDER AUTOMATION	10	REVISED	NOTES AND BOM CHANGE
26	EMMA HALILOVIC	10-3710		SCADA ANTENNA MOUNTING DETAIL	10	REVISED	DRAWING CHANGE
27	EMMA HALILOVIC	11-0000		INDEX OF STANDARDS	11	REVISED	Revised to include new Standard 11-3600
28	EMMA HALILOVIC	11-2020		OVERHEAD SECONDARY SECONDARY BUS, TRANSFORMER SECONDARY DROP LEADS AND SECONDARY SERVICES	11	REVISED	Revised Secondary Services Notes
29	EMMA HALILOVIC	11-3210		MULTIPLEXED SECONDARY BUS SERVICE TAPS 120/240 V AT POLE	11	REVISED	Removed 400A service size, replaced solid bail with flexible bail grip wedge
30	EMMA HALILOVIC	11-3250		MULTIPLEXED SECONDARY BUS SERVICE TAPS 120/240 V AT MID-SPAN	11	REVISED	Removed 400A service size, replaced solid bail with flexible bail grip wedge
31	EMMA HALILOVIC	11-3600		MULTIPLEXED SECONDARY BUS SERVICE TAP AT TRANSFORMER POLE 120/240 V 400 A	11	NEW	New Standard
32	EMMA HALILOVIC	11-5200		OVERHEAD SECONDARY SERVICES SERVICE ENTRANCE 120/240 V CONNECTION TO CUSTOMER'S SERVICE MAST	11	REVISED	Added 400A service size for Commercial service type
33	JAMES DANIEL	12-1200		RISER INSTALLATION DETAILS - CABLE GUARD OR GALVANIZED PIPE	12	REVISED	Updated dimensions, notes, BOM, pictorial revisions
34	JOHN HECIMOVIC	12-3000		PRIMARY SERVICE RISERS PRIMARY DROPS AND CONNECTORS FOR 1-PHASE SERVICE RISER	12	REVISED	- REVIEW STANDARD TO REPLACE SOLID TAPS WITH REMOVABLE HOT LINE CONNECTORS - ADD ONE INSULATOR TO HALO TOP PHASE, VERTICAL TOP AND MIDDLE PHASE, SEMI-TRIANGULAR TOP PHASE, IN-LINE ROLLED TOP AND MIDDLE PHASE
35	JOHN HECIMOVIC	12-3100		PRIMARY SERVICE RISERS PRIMARY DROPS AND CONNECTORS FOR 3-PHASE SERVICE RISER	12	REVISED	- REVIEW STANDARD TO REPLACE SOLID TAPS WITH REMOVABLE HOT LINE CONNECTORS - ADD ONE INSULATOR TO VERTICAL, IN-LINE ROLLED, SEMI-TRIANGULAR, HALO

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #44

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
36	JOHN HECIMOVIC	12-3600		PRIMARY SERVICE RISER (200A MAX) FUSED 3 PHASE FOR 27.6 KV DELTA TRANSFORMER	12	REVISED	NOTES AND BOM CHANGE
37	KALYAN SARKAR	15-2000		SECONDARY UNDERGROUND SERVICES 100A INTRODUCTION	15	REVISED	NOTE ADDED
38	KALYAN SARKAR	16-0020		GENERAL INFORMATION OF CABLES	16	REVISED	REVISED DRAWING
39	KALYAN SARKAR	16-0350		PRIMARY CABLES CROSSBONDING SCHEME FOR TRXLPE CABLE 15kV , 1 CONDUCTOR, CU, 1000 kcmil AND LARGER	16	REVISED	DOC
40	KALYAN SARKAR	16-3820		Primary - Polymeric Cable Straight Joints Cold Shrink Method, 15kV, 1 Conductor	16	REVISED	NOTES AND BOM CHANGE
41	KALYAN SARKAR	16-4100		Primary - Polymeric Cable Terminations TRXLPE - OUTDOOR -COLD SHRINK,15KV,1 CON	16	Revised	NOTES AND BOM CHANGE
42	KALYAN SARKAR	16-4600		PRIMARY - INLINE TRANSITION JOINT HAND TAPING METHOD	16	REVISED	NOTES AND BOM CHANGE
43	JOHN HECIMOVIC	16-5200		SECONDARY - STRAIGHTJOINT COLD SHRINK METHOD 600V AND BELOW, 1 COND	16	Revised	REVISED DRAWING
44	JAMES DANIEL	18-5000		UNDERGROUND SYSTEMS GUARD POST GUARDING DETAIL	18	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
45	JOHN HECIMOVIC	21-0000		INDEX OF STANDARDS	21	REVISED	INDEX CHANGE NEW STANDARD
46	JOHN HECIMOVIC	21-2100		OVERHEAD STENCILING POLE NUMBERING	21	REVISED	TEXT CHANGE
47	JOHN HECIMOVIC	21-2120		OVERHEAD STENCILING REDUCED POLE HEIGHT IDENTIFICATION	21	NEW	NEW STANDARD

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #44

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
48	KALYAN SARKAR	21-4200		UNDERGROUND STENCILING PRIMARY CABLE LABELLING	21	NEW	NEW STANDARD
49	KALYAN SARKAR	21-4300		UNDERGROUND STENCILING SECONDARY CABLE LABELLING	21	NEW	NEW STANDARD
50	JAMES DANIEL	23-1220		OVERHEAD SYSTEM - COMMUNICATION CABLE UNDERGROUND RISER	23	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
51	JAMES DANIEL	23-2020		UNDERGROUND SYSTEM - DUCT OCCUPANCY COMMUNICATION CABLE GENERAL INFORMATION	23	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
52	JAMES DANIEL	23-2030		UNDERGROUND SYSTEM - DUCT OCCUPANCY COMMUNICATION CABLE WITHIN CABLE CHAMBERS	23	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
53	JOHN HECIMOVIC	24-1200		FUSING AT RISER POLES	24	REVISED	DOC
54	JAMES DANIEL	30-0000		INDEX OF STANDARDS	30	REVISED	STANDARD OBSOLETED
55	JAMES DANIEL	30-9560		Wall Mounting Plate and Bracket	30	REVISED	Full Review and Evaluation
56	JAMES DANIEL	31-1230		CONDTUITS SUPPLYING CUSTOMER'S BUILDING	31	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
57	JAMES DANIEL	31-1240		Conduits Civil Underground Secondary Service Projects Conversion From Overhead To Underground Feed and Underground To Underground Feed	31	REVISED	Full Review and Evaluation
58	JAMES DANIEL	31-1250		CONDUITS UNDERGROUND SECONDARY SERVICE PROJECTS FOR NEW INSTALLATION	31	REVISED	REVISE WORD CONTENT
59	JAMES DANIEL	31-2170		CABLE CHAMBERS	31	REVISED	REVISED DRAWING AND BOM

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #44

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
60	JAMES DANIEL	31-4015		PAD-MOUNTS CLEARANCE ZONE	31	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
61	JAMES DANIEL	31-4020		PAD-MOUNTS - SINGLE PHASE PRECAST PAD-MOUNT 1070mm X 1320mm X 1350mm	31	REVISED	DRAWING REVISION
62	JAMES DANIEL	31-4030		PAD-MOUNTS - 3-PHASE PRECAST PAD-MOUNT 1830mm X 1830mm X 1220mm	31	REVISED	DRAWING REVISION
63	JAMES DANIEL	31-4040		PAD-MOUNTS - 3-PHASE PMH 4 - 25kV SWITCHGEAR	31	REVISED	DRAWING REVISION
64	JAMES DANIEL	31-4050		PAD-MOUNTS - 3-PHASE PMH 9/11 SWITCHGEAR	31	REVISED	DRAWING REVISION
65	JAMES DANIEL	31-4080		PAD-MOUNTS GUARD POSTS (BOLLARDS)	31	REVISED	UPDATE DIMENSIONS,NOTES, BOM PICTORIAL REVISIONS
67	JAMES DANIEL	31-8310		Switch / Splice Vault Cover	31	REVISED	COMPLETED REVIEW OF STANDARD

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
01	JAMES DANIEL	03-2000		OVERHEAD - MINIMUM CLEARANCES STANDARD ATTACHMENT POINTS	03	REVISED	Updated dimensions, notes, BOM, pictorial revisions
02	JAMES DANIEL	03-2300		OVERHEAD - MINIMUM CLEARANCES BUILDINGS AND PERMANENT STRUCTURES	03	REVISED	Jeffry: Revised notes and revised dimensions
03	JAMES DANIEL	04-5200		CEDAR AND CONCRETE POLES IN BOULEVARD (HAND DIG AND VACUUM TRUCK)	04	REVISED	Updated dimensions, notes, BOM, pictorial revisions
04	JAMES DANIEL	04-5300		CEDAR AND CONCRETE POLES IN SIDEWALK	04	REVISED	Updated dimensions, notes, BOM, pictorial revisions
05	JAMES DANIEL	04-5400		CEDAR AND CONCRETE POLES IN BOULEVARD AND SIDEWALK, FOR TTC TROLLEY SUSPENSION	04	REVISED	Updated dimensions, notes, BOM, pictorial revisions
06	JAMES DANIEL	04-5500		CEDAR AND CONCRETE POLES IN POOR SOIL	04	REVISED	Updated dimensions, notes, BOM, pictorial revisions
07	JAMES DANIEL	04-5600		CEDAR AND CONCRETE POLES IN SLOPES AND HILLSIDES	04	REVISED	Updated dimensions, notes, BOM, pictorial revisions
08	ROB MCKEOWN / JAMES DANIEL	05-0000		INDEX OF STANDARDS	05	REVISED	Added new standard
09	ROB MCKEOWN / JAMES DANIEL	05-1200		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY 3-PHASE HALO CONFIGURATION ANGLES 0 TO 15 DEGREES	05	REVISED	Added MIN to clearance dimension
10	ROB MCKEOWN / JAMES DANIEL	05-1260		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY 3-PHASE IN-LINE ROLLED CONFIGURATION ANGLES 0 TO 3 DEGREES	05	REVISED	Added MIN to clearance dimension
11	ROB MCKEOWN / JAMES DANIEL	05-1590		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY 3-PHASE DOUBLE DEAD-END HORIZONTAL CONFIGURATION	05	NEW	NEW STANDARD
12	ROB MCKEOWN / TAREK TURK	05-1800		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY 3-PHASE DOUBLE CIRCUIT VERTICAL ANGLES 46 TO 90 DEGREES	05	REVISED	Updated extension insulator to new stock code.
13	ROB MCKEOWN / JAMES DANIEL	05-1860		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY DOUBLE 3-PHASE DEAD-END VERTICAL CONFIGURATION	05	REVISED	Updated extension insulator to new stock code.
14	JAMES DANIEL	05-2170		4.16 TO 27.6 kV TREEPROOF AND BARE PRIMARY - 3-PHASE RUNOFF FROM 3-PHASE HALO	05	REVISED	updated stock code for item 26

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
15	ROB MCKEOWN / JAMES DANIEL	05-2460		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY 3-PHASE MID-SPAN TAP HORIZONTAL CONFIGURATION	05	REVISED	Added Note stating that main circuit pole to be 5' higher than tap pole.
16	ROB McKEOWN	06-0000		INDEX OF STANDARDS	06	REVISED	Added new standards
17	ROB McKEOWN	06-5100		SAGS AND TENSIONS TABLE 3 – #1/0 QUADRUPLEX SERVICE CONDUCTORS WITH #1/0 ACSR NEUTRAL PVC JACKET 15M-30M SPANS	06	NEW	NEW STANDARDS
18	ROB McKEOWN	06-5110		SAGS AND TENSIONS TABLE 2 - #4/0 TRIPLEX SERVICE CONDUCTORS WITH #2/0 ACSR NEUTRAL 15M-30M SPANS	06	NEW	NEW STANDARD
19	ROB McKEOWN	06-5120		SAGS AND TENSIONS TABLE 3 - #1/0 QUADRUPLEX SERVICE CONDUCTORS WITH #1/0 ACSR NEUTRAL 15M-30M SPANS	06	NEW	NEW STANDARD
20	ROB McKEOWN	06-5130		SAGS AND TENSIONS TABLE 2 - #2 TRIPLEX SERVICE CONDUCTORS WITH #4 ACSR NEUTRAL 15M-30M SPANS	06	NEW	NEW STANDARD
21	ROB McKEOWN	06-5140		SAGS AND TENSIONS TABLE 3 - #4 QUADRUPLEX SERVICE CONDUCTORS WITH #4 ACSR NEUTRAL 15M-30M SPANS	06	NEW	NEW STANDARD
22	ROB McKEOWN	06-5150		SAGS AND TENSIONS TABLE 2 - #4 TRIPLEX SERVICE CONDUCTORS WITH #4 ACSR NEUTRAL 15M-30M SPANS	06	NEW	NEW STANDARD
23	ROB McKEOWN	06-6100		SAGS AND TENSIONS TABLE 15M SLACK SPAN SAGS AND TENSIONS FOR BARE PRIMARY CONDUCTORS	06	NEW	NEW STANDARD
24	ROB McKEOWN	06-6200		SAGS AND TENSIONS TABLE 15M SLACK SPAN SAGS AND TENSIONS FOR TREEPROOF PRIMARY CONDUCTORS	06	NEW	NEW STANDARD
25	ROB McKEOWN	06-6300		SAGS AND TENSIONS TABLE 15M SLACK SPAN SAGS AND TENSIONS FOR SECONDARY BUS CONDUCTORS	06	NEW	NEW STANDARD
26	ROB/TAREK	07-0000		INDEX OF STANDARDS	07	REVISED	Added new standard
27	ROB/TAREK	07-1000		ANCHORING - INTRODUCTION AND SOILD CLASSIFICATIONS	07	REVISED	Added sentence indicating soil maps are available on Plugged In
28	ROB/TAREK	07-1200		ANCHOR SELECTION HOLDING CAPACITIES FOR VARIOUS SOIL CLASSES	07	REVISED	Updated to include additional anchor types

DISTRIBUTION CONSTRUCTION STANDARDS

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
29	ROB/TAREK	07-3000		GUYING - GENERAL INFORMATION	07	REVISED	Added comment that other pole loading analysis software could be used.
30	ROB/TAREK	07-3100		GUYING - GUY SELECTION	07	REVISED	Added comment that other pole loading analysis software could be used.
31	ROB/TAREK	07-3200		GUYING - DETERMINE ULTIMATE LOAD AND GUY TENSION	07	REVISED	Added comment that other pole loading analysis software could be used.
32	ROB/TAREK	07-3300		GUYING - BISECTOR CHART METHOD	07	REVISED	Added comment that other pole loading analysis software could be used.
33	ROB/TAREK	07-3400		GUYING - LINE TERMINATION CHART METHOD	07	REVISED	Added comment that other pole loading analysis software could be used.
34	ROB/TAREK	07-4250		GUYING - INSTALLATION PROCEDURE - STRUT GUY	07	REVISED	Updated to show detail for 3 wire strut guy clamp.
35	ROB/TAREK	07-4320		GUYING - INSTALLATION DETAILS - GUY ATTACHMENTS TO STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.
36	ROB/TAREK	07-5100		DOWN GUY – ONE ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.
37	ROB/TAREK	07-5200		STRUT GUY – ONE ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.
38	ROB/TAREK	07-5250		STRUT GUYS - THREE ON CONCRETE OR WOOD POLE USING INSULATOR ROD(S)	07	NEW	NEW STANDARD
39	ROB/TAREK	07-5300		SPAN & DOWN GUY – ONE ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.
40	ROB/TAREK	07-5310		SPAN & DOWN GUY – ONE ON CONCRETE, WOOD OR STEEL POLE USING INSULATOR ROD	07	REVISED	Updated pole band clamp for steel poles to new stock code.
41	ROB/TAREK	07-5320		SPAN & DOWN GUYS – TWO ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.
42	ROB/TAREK	07-5340		SPAN & STRUT GUY – ONE ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
43	ROB/TAREK	07-5350		SPAN & STRUT GUY – ONE ON CONCRETE, WOOD OR STEEL POLE USING INSULATOR ROD	07	REVISED	Updated pole band clamp for steel poles to new stock code.
44	ROB/TAREK	07-5370		SPAN & STRUT GUYS – TWO ON CONCRETE, WOOD OR STEEL POLE WITH ONE SPAN GUY USING INSULATOR ROD	07	REVISED	Updated pole band clamp for steel poles to new stock code.
45	ROB/TAREK	07-5500		SPAN GUY – ONE ON CONCRETE, WOOD OR STEEL POLE	07	REVISED	Updated pole band clamp for steel poles to new stock code.
46	ROB/JOHN	08-3510		LIVE LINE - STIRRUP APPLICATION AND SELECTION TABLE	08	REVISED	Updated to add 795 conductor
47	JOHN HECIMOVIC	09-8100		1-PHASE CONSTRUCTION - 2400-120/240 V - ALL kVA SIZES	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
48	JOHN HECIMOVIC	09-8200		1-PHASE CONSTRUCTION - 8000-120/240 V - ALL kVA SIZES	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
49	JOHN HECIMOVIC	09-8300		1-PHASE CONSTRUCTION - 16000-120/240 V - ALL kVA SIZES	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
50	JOHN HECIMOVIC	09-8400		3-PHASE CONSTRUCTION - 2400/4160 - 120/208 V - 50 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
51	JOHN HECIMOVIC	09-8500		3-PHASE CONSTRUCTION - 2400/4160 - 120/208 V - 100 & 167 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
52	JOHN HECIMOVIC	09-8600		3-PHASE CONSTRUCTION - 8000-120/208 V - 50 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
53	JOHN HECIMOVIC	09-8700		3-PHASE CONSTRUCTION - 8000-120/208 V - 100 & 167 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
54	JOHN HECIMOVIC	09-8800		3-PHASE CONSTRUCTION - 16000/27600 - 120/208 V - 50 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
55	JOHN HECIMOVIC	09-8900		3-PHASE CONSTRUCTION - 16000/27600 - 120/208 V - 100 & 167 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
56	JOHN HECIMOVIC	09-9100		3-PHASE CONSTRUCTION - 2400/4160 - 347/600 V WYE 100 & 167 kVA	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
57	JOHN HECIMOVIC	09-9200		3-PHASE CONSTRUCTION - 8000/13800 - 347/600 V WYE ALL kVA SIZES	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
58	JOHN HECIMOVIC	09-9300		3-PHASE CONSTRUCTION - 16000/27600 - 347/600 V WYE ALL kVA SIZES	09	REVISED	Added detail 'C' and a note for installation of stick pins; added max and min height for clearances
59	EMMA HALILOVIC	10-0000		INDEX OF STANDARDS	10	REVISED	Standards title change and added new standard
60	EMMA HALILOVIC	10-1120		DISCONNECT IN-LINE SWITCHES FUSED 200 A DOUBLE DEAD-END 13.8 kV TO 27.6 kV HORIZONTAL CONFIGURATION	10	REVISED	Removed 11" insulator rod from BOM
61	EMMA HALILOVIC	10-1660		13.8 kV & 27.6 kV BARE AND TREEPROOF 3-PHASE FUSED RUN-OFFS VERTICAL CONSTRUCTION FUSED ISOLATION	10	REVISED	Revised BOM & BOM References
62	EMMA HALILOVIC	10-3100		3-PHASE LOAD INTERRUPTER SWITCH SCADA-OPERATED 13.8 & 27.6 kV FEEDER RISER	10	REVISED	Added Note 12 regarding Feeder Automation
63	EMMA HALILOVIC	10-3500		3-PHASE LOAD INTERRUPTER SWITCH SCADA-OPERATED 13.8 & 27.6 kV TIERED OUTBOARD TYP	10	REVISED	Added Switch Dimensions, Added Insulator Extension Link to BOM
64	EMMA HALILOVIC	10-3700		COMMUNICATION AND CONTROL UNIT (CCU) SCADA AND FEEDER AUTOMATION	10	REVISED	Revised Notes, Added Switch Reference Standard in BOM
65	ROB MCKEOWN / TAREK TURK	11-5200		120/240 V CONNECTION TO CUSTOMER'S SERVICE MAST	11	REVISED	Updated to allow use of Insulinks
66	ROB MCKEOWN / TAREK TURK	11-5220		120/208 V CONNECTION TO CUSTOMER'S SERVICE MAST	11	REVISED	Updated to allow use of Insulinks
67	ROB MCKEOWN / TAREK TURK	11-5240		347/600 V CONNECTION TO CUSTOMER'S SERVICE MAST	11	REVISED	Updated to allow use of Insulinks
68	ROB MCKEOWN / TAREK TURK	11-5300		120/240 V CONNECTION TO CUSTOMER'S SERVICE MAST WITH ALLEY JUMP	11	REVISED	Updated to allow use of Insulinks
69	James Daniel	12-1200		RISER INSTALLATION DETAILS - CABLE GUARD OR GALVANIZED PIPE	12	REVISED	Revised drawings, BOM, notes
70	IGOR SIMONOV	13-2010		4.16 KV TRANSFORMER VAULT LAYOUT AND INSTALLATION	13	REVISED	Updated layout, BOM, notes

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
71	IGOR SIMONOV	13-7010		1 PH SUBMERSIBLE VAULT	13	REVISED	SPLIT 11"X17" TO 8.5"X11", UPDATE BOM AND REFERENCES
72	JOHN HECIMOVIC	13-7810		PAD-MOUNTED DEAD FRONT 27.6kV SWITCHGEAR EQUITO PMH-9	13	REVISED	NOTES REVISED
73	JOHN HECIMOVIC	13-7820		PAD-MOUNTED DEAD FRONT 27.6kV SWITCHGEAR EQUITO PMH-11	13	REVISED	NOTES REVISED
74	IGOR SIMONOV	14-3500		INSTALLATION 27.6 Kv 1 PHASE LOW PROFILE 27.6 KV	14	REVISED	CRF-2014-0345. Revised standard to include number of terminations, added cable type options, updated BOM
75	JAMES DANIEL	15-8300		INSTALLATION OF 28 kV, #1/0 TRXPLE CABLES IN SUBMERSIBLE TRANSFORMER VAULT CONVERTED TO A SPLICE VAULT	15	REVISED	Updated dimensions, notes, BOM, pictorial revisions
76	IGOR SIMONOV	16-0000		INDEX OF STANDARDS	16	REVISED	REVISED NEW STANDARD ADDED
77	KALYAN SARKAR	16-2340		CABLE JOINTS AND TERMINATIONS GENERAL INSTALLATION INSTRUCTIONS	16	REVISED	REVISED NEW STANDARD ADDED
78	KALYAN SARKAR	16-2350		PRIMARY-JOINT Joint Slice kit quk selection chart	16	REVISED	REVISED NEW STANDARD ADDED
79	KALYAN SARKAR	16-3770		PRIMARY- TRXLPE STRAIGHT JOINT HEAT SHRINK SPLICE REDUCING 15kV 1 CONDUCTOR	16	REVISED	REVISED NEW STANDARD ADDED
80	JOHN HECIMOVIC	16-4180		PRIMARY - TRXLPE TERMINATIONS 600A DEADBREAK CONNECTORS 15 kV 1 COND.	16	REVISED	Revised drawings, BOM, notes
81	JOHN HECIMOVIC	16-4260		PRIMARY TRXLPE TERMINATIONS 600 A DEADBREAK CONNECTORS 28 KV 1 COND	16	REVISED	Revised drawings, BOM, notes
82	Kalyan Sarkar	16-4610		PRIMARY INLINE TRANSITION JOINT HEAT SHRINK SPLICE 15kV 1C PILC TO 1C TRXLPE	16	NEW	New standard to show details for 1 ph pad/submersible transformers secondaries terminations
83	Kalyan Sarkar	16-4340		PRIMARY TRXLPE TERMINATIONS 600 A DEADBREAK STRAIGHT RECEPTACLES 15kV 1 COND	16	REVISED	Revised drawings, BOM, notes
84	IGOR SIMONOV	16-6000		SECONDARY TERMINATIONS SUBMERSIBLE TRANSFORMER TERMINAL CLUSTER 600 V OR BELOW	16	REVISED	CRF-2014-0343. Revised standard to include number of terminations, added cable type options updated BOM

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
85	IGOR SIMONOV	16-6020		SECONDARY TERMINATIONS 1 PH SUBMERSIBLE AND 1 PH PADMOUNTED TRANSFORMERS	16	NEW	New standard to show details for 1 ph pad/submersible transformers secondaries terminations
86	IGOR SIMONOV	16-6040		SECONDARY TREMINAL LIGS TERMINATION	16	NEW	Provide details for secondary terminal lugs termination
87	KALYAN SARKAR	16-6210		CABLE REEL DATA CABLE AND WIRE REEL CHART	16	REVISED	REVISED NEW STANDARD ADDED
88	JAMES DANIEL/IGOR	17-0000		INDEX OF STANDARDS	17	REVISED	UPDATED STANDARDS LIST AND DESCRIPTION
89	JAMES DANIEL	17-2250		MINIMUM CLEARANCE BETWEEN METER SOCKET AND GAS RELIEF VENT	17	NEW	NEW STANDARD
90	JAMES DANIEL	17-2300		SECONDARY- RESIDENTIAL TYPICAL MOUNTING LOCATION	17	REVISED	Updated dimensions, notes, BOM, pictorial revisions
91	TAREK TURK	17-3100		S-BASE SOCKET TYPE TYPICAL TERMINATOR ARRANGEMENTS	17	REVISED	Updated dimensions, notes, BOM, pictorial revisions
92	JAMES DANIEL	18-0000		INDEX OF STANDARDS	18	REVISED	Updated dimensions, notes, BOM, pictorial revisions
93	JAMES DANIEL	18-3200		OVERHEAD SYSTEM - CABLE GUARD OR GALVANIZED PIPE	18	REVISED	Updated dimensions, notes, BOM, pictorial revisions
94	JAMES DANIEL	18-3250		OVERHEAD SYSTEM CABLE GUARD FOR DIRECT BURIED CABLE	18	REVISED	Updated dimensions, notes, BOM, pictorial revisions
95	EMMA HALILOVIC	18-3600		OVERHEAD SYSTEM NEUTRAL BONDING	18	REVISED	Revised BOM, Added Reference to Std 18-4100
96	EMMA HALILOVIC	18-4100		OVERHEAD SYSTEM COMMUNICATION MESSENGER BONDING	18	REVISED	Revised Title, Added BOM. Added Reference to Section 23
97	JAMES DANIEL	18-5000		UNDERGROUND SYSTEMS GROUND POST GROUNDING DETAILS	18	REVISED	Updated dimensions, notes, BOM, pictorial revisions
98	IGOR SIMONOV	18-5200		Underground System Submersible or Splice Vault	18	REVISED	UPDATED BOM, REFERENCES, DRAWING TO REFLECT MU SPLIT WITH 13-7010

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
99	JAMES DANIEL	18-5400		UNDERGROUND SYSTEM SPLICE VAULT 'B'	18	REVISED	Updated dimensions, notes, BOM, pictorial revisions
100	JOHN HECIMOVIC	21-1100		GENERAL INFORMATION STENCILING MATERIALS	21	REVISED	INFORMATION CORRECTION
101	JOHN HECIMOVIC	21-2400		IN-LINE SWITCH NUMBERING	21	REVISED	INFORMATION CORRECTION
102	ROB MCKEOWN / JAMES DANIEL	23-0000		INDEX OF STANDARDS	23	REVISED	Removed obsolete standard
103	ROB MCKEOWN / JAMES DANIEL	23-1200		OVERHEAD SYSTEM POLE ATTACHMENTS - COMMUNICATION CABLE ATTACHMENTS	23	REVISED	Added wording to Anchors section. Added details to diagram.
104	ROB MCKEOWN / JAMES DANIEL	23-1210		COMMUNICATION CABLE LOCATIONS ON POLES	23	OBSOLETE	OBSOLETED NO LONGER REQUIRED
105	ROB MCKEOWN / JAMES DANIEL	23-1220		OVERHEAD SYSTEM POLE ATTACHMENTS - COMMUNICATION RISER AND NEUTRAL BONDING	23	REVISED	Revised diagram
106	John Hecimovic	24-1100		OVERHEAD FUSING TRANSFORMRERS	24	REVISED	Updated note
107	IGOR SIMONOV	24-2100		UNDERGROUND FUSING FOR NETWORK PROTECTORS	24	REVISED	Revised to to remove 9663518
108	EMMA HALILOVIC	30-1100		GENERAL INFORMATION	30	REVISED	Changed general information
109	James Daniel	30-4210		ALUMINUM POLE WITH COBRA HEAD LUINAIRE	30	REVISED	Revised drawing, dimensions, notes and BOM
110	James Daniel	31-0000		INDEX OF STANDARDS	31	REVISED	Revise Standard Title's in index to match with the corresponding Standard
111	JAMES DANIEL	31-0100		UNDERGROUND CLEARANCES	31	REVISED	Updated note
112	JAMES DANIEL	31-1120		CONDUITS CONCRETE ENCASED AND DIRECT BURIED DUCTS	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
113	JAMES DANIEL	31-1250		CONDUITS UNDERGROUND SECONDARY SERVICE PROJECTS FOR NEW INSTALLATION	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
114	JAMES DANIEL	31-1310		CABLE CHAMBERS LID PLACEMENT	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
115	JAMES DANIEL	31-2010		CABLE CHAMBERS GENERAL INFORMATION AND GUIDELINES	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
116	JAMES DANIEL	31-2120		CABLE CHAMBERS LID PLACEMENT	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
117	JAMES DANIEL	31-2130		CABLE CHAMBERS STRUCTUAL DETAIL	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
118	JAMES DANIEL	31-2140		CABLE CHAMBERS DEEP NECK CHAMBERS STRUCTUAL DETAILS	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
119	JAMES DANIEL	31-2160		CABLE CHAMBERS PRECAST CHAMBER	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
120	JAMES DANIEL	31-2180		CABLE CHAMBERS TYPICALRACKING ARRANGEMENTS	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
121	JAMES DANIEL	31-2240		VAULTS SPLICE 'B' - 3 PIECE PRECAST	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
122	JAMES DANIEL	31-4080		CABLE CHAMBERS LID PLACEMENT	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
123	JAMES DANIEL	31-5120		SPLICE VAULT 'A' FOR 1000 kcmil CABLES	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
124	James Daniel	31-8260		MATERIAL FABRICATION - CABLE RACK	31	REVISED	Revised BOM
125	JAMES DANIEL	31-8270		MATERIAL FABRICATION CABLE ARMS	31	REVISED	Updated dimensions, notes, BOM, pictorial revisions
126	ROB MCKEOWN / TAREK TURK	34-0000		INDEX OF STANDARDS	34	REVISED	Revised to add 34-1000

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #45

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
127	ROB MCKEOWN / TAREK TURK	34-1000		CONSTRUCTION DEVIATION GUIDELINES	34	NEW	New Constructin deviation

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #46

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
1	JAMES DANIEL	03-2150		OVERHEAD MINIMUM VERTICAL CLEARANCES ABOVE GROUND OR RAILS	03	REVISED	Jeffry: Revised notes and revised dimensions
2	JAMES DANIEL	04-5600		CEDAR AND CONCRETE POLES	04	REVISED	CHANGE IN TEXT PLEASE REPLACE OLD ONE
3	ROB MCKEOWN	05-0000		INDEX OF STANDARDS	05	REVISED	ADD NEW STANDARD
4	ROB MCKEOWN	05-1130		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY MID-SPAN OPENER	05	NEW	New sketch, contains mid-span opener, front and isometric view
5	ROB MCKEOWN / JAMES DANIEL	05-1580		4.16 TO 27.6 KV TREEPROOF AND BARE PRIMARY 3-PHASE DOUBLE DEAD-END OR TRANSITION BETWEEN BARE AND TREEPROOF HORIZONTAL CONFIGURATION	05	REVISED	Added notes indicating line angles that can be accomodated.
6	ROB MCKEOWN	05-1590		3-PHASE DOUBLE DEAD-END HORIZONTAL CONFIGURATION	05	REVISED	Added Bolt and Guy and revised BOM
7	ROB MCKEOWN	05-1880		DOUBLE 3-PHASE DOUBLE DEAD-END OR TRANSITION BETWEEN BARE AND TREEPROOF VERTICAL CONFIGURATION	05	REVISED	Added Bolt and Guy and revised BOM
8	ROB MCKEOWN	05-2030		4.16 TO 27.6 kV TREEPROOF AND BARE PRIMARY 1-PHASE RUN-OFF FROM 3-PHASE HORIZONTAL	05	REVISED	Added figure 2 which provides outside phase run-off
9	JAMES DANIEL	05-6070		SYSTEM NEUTRAL TAP AND RUN-OFF	05	REVISED	REVISED BOM FOR PERMUTATION G, H, I
10	ROB MCKEOWN	06-1000		INTRODUCTION	06	REVISED	Additional wording added to Initial Sags section
11	IGOR SIMONOV	09-1400		GENERAL INFORMATION BUSHING CONFIGURATION	09	REVISED	including two tools method field connection to terminal tap
12	IGOR SIMONOV	09-9200		3-PH CONSTRUCTION 8000/13800-347/600 VV WYE ALL SIZE	09	REVISED	double up secondary drop leads for a 167unit shall not apply to std. 09-9100
13	IGOR SIMONOV	09-9300		3-PH CONSTRUCTION 16000/27600-347/600 VV WYE ALL SIZE	09	REVISED	double up secondary drop leads for a 167unit shall not apply to std. 09-9100
14	EMMA HALILOVIC	10-1300		ALL VOLTAGES AND CONFIGURATIONS	10	REVISED	Drawing,Comment and BOM change
15	EMMA HALILOVIC	10-2400		MANUALLY OPERATED 13.8kV & 27.6kV FEEDER RISER	10	REVISED	Added Dimensions, Revise BOM and added details
16	EMMA HALILOVIC	10-2600		MANUALLY OPERATED13.8kV and 27.6kV TIER OUTBOARD TYPE	10	REVISED	Added Dimensions, Revise BOM and added details
17	EMMA HALILOVIC	10-3100		SCADA-OPERATOR 13.8 & 27.6kV FEEDER RISER	10	REVISED	Added Detail 'A', 'B', 'C'; Added dimensions and clearances, gonding schematic; Edited notes, BOM and BOM legend
18	EMMA HALILOVIC	10-3700		COMMUNICATION AND CONTROL UNIT(CCU) SCADA AND FEEDER AUTOMATION	10	REVISED	Revised notes
19	ROB MCKEOWN	11-3170		MULTIPLEXED SECONDARY BUS - DEAD -END ON TTC STEEL POLE	11	REVISED	Added Double Dead-End option and revised BOM

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #46

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
20	ROB MCKEOWN	11-3180		MULTIPLEXED SECONDARY BUS - DEAD -END ON CONCRETE OR WOOD POLE	11	REVISED	Added Double Dead-End option and revised BOM
21	ROB MCKEOWN	11-3190		MULTIPLEXED SECONDARY BUS - TURNING ANGLE 4 TO 90 DEGREES ON TTC STEEL POLE	11	REVISED	Revised BOM
22	ROB MCKEOWN/JOHN HECIMOVIC	12-3500		PRIMARY SERVICE RISERS - FUSED 3-PHASE WITH CLF 13.8kV & 27.6kV GRD Y	12	REVISED	NEW REVISION OF AN OLD STANDARD THAT WAS OBSOLETE.
23	IGOR SIMONOV	13-5010		13.8 Kv NETWORK SYSTEM NETWORK TRANSFORMER VAULTS	13	REVISED	BOM CHANGED
24	IGOR SIMONOV	13-7010		27.6 Kv or 13.8 Kv 1PH SUBMERSIBLE TRANSFORMER VAULT	13	REVISED	NOTE CHANGED AND BOM CHANGED
25	IGOR SIMONOV	14-1030		13.8 Grd. Y 8.0 kV 1 PH URD/LOOP SYSTEM	14	REVISED	NOTE CHANGED
26	IGOR SIMONOV	14-1040		13.8 kV 3 PH RADIAL DELTA PRIMARY CONNECTION	14	REVISED	NOTE CHANGED
27	IGOR SIMONOV	14-1050		13.8 kV 3 PH RADIAL URD/LOOP SYSTEM	14	REVISED	NOTE CHANGED
28	IGOR SIMONOV	14-1060		27.6 Grd. Y 16 Kv 1-1PH RADIAL/LOOP SYSTEM	14	REVISED	NOTE CHANGED
29	IGOR SIMONOV	14-1070		27.6 Grad. 16kV 3-PH RADIAL/LOOP SYSTEM	14	REVISED	NOTE CHANGED
30	IGOR SIMONOV	14-3600		INSTALLATION-27.6Kv RADIAL / LOOP	14	REVISED	NOTE CHANGED
31	KAL SARKAR	15-3760		SECONDARY 120/240V UNDERGROUND SERVICE UP TO 200A TYPICAL TAP BOX USING E TYPE CONNECTORS	15	REVISED	Full Review and Evaluation
32	KAL SARKAR	15-8200		PRIMARY SERVICES	15	REVISED	REVISION OF BOM
33	KAL SARKAR	16-0000		INDEX OF STANDARDS	16	REVISED	Added Std. 16-2360
34	KAL SARKAR	16-0280		600V SECONDARY TERMINALS	16	REVISED	PART NUMBER CHANGES
35	KAL SARKAR	16-1220		TABLE OF RATINGS OF CABLES 600 V SECONDARY BUS AND SERVICE CABLES	16	REVISED	TEXT AND BOM CHANGE
36	KAL SARKAR	16-2340		CABLE JOINTS AND TERMINATIONS - GENERAL INSTALLATION INSTRUCTIONS	16	REVISED	Changed stock code from the old to the newly approved 4-panel windshield (pg.8)
37	KAL SARKAR	16-2360		Primary - Termination, Termination Kit Quick Selection Chart	16	New	Created selection chart for termination kit
38	ROB MCKEOWN	23-1020		OVERHEAD 120 V UNMETERED CONNECTION SERVICES ATTACHED TO TORONTO HYDRO POLES	23	REVISED	Revised notes

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #46

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
39	ROB MCKEOWN	23-1030		UNDERGROUND 120 V UNMETERED CONNECTION SERVICES ATTACHED TO TORONTO HYDRO POLES	23	REVISED	Revised notes
40	JAMES DANIEL	23-1150		Temporary Decorative Pole Wrap	23	REVISED	Revised notes and made adjustments to dimensions
41	JAMES DANIEL	30-5000		Decorative Streetlighting Pole Capella Pole 30' - Yonge Street (Dundas to Shuter)	30	REVISED	Revised drawing, dimensions, notes and BOM
42	JAMES DANIEL	31-1240		Residential Underground Secondary Service Rebuilds	31	REVISED	Revised notes, drawing, and dimensions
43	JAMES DANIEL	31-1390		Conduits Joint Trenching	31	REVISED	MEASUREMENT CHANGE
44	JAMES DANIEL	31-5120		SPLICE VAULT 'A' FOR 1000 kcmil CABLES - 1625 mm (5'-4") x 2750 mm (9'-0")	31	REVISED	Edited diagrams and Revised Note
45	ROB MCKEOWN / TAREK TURK	34-1000		CONSTRUCTION DEVIATION GUIDELINES	34	REVISED	Revised to show that relocating pole mount transformer is a technical deviation due to voltage drop calculations.

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #47

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
1	Rob McKeown	03-0000		INDEX OF STANDARDS	03	Revised	Revised to add new Standard
2	Rob McKeown	03-1100		Overhead - General Information	03	Revised	revised point 10 to reflect new standard 03-2310
3	Rob McKeown	03-2000		Overhead - Minimum Clearances	03	Revised	revised point 10 to reflect new standard 03-2310
4	Rob McKeown	03-2150		Overhead - Minimum Clearances	03	Revised	Drawing revised
5	Rob McKeown	03-2250		Overhead - Minimum Clearances	03	Revised	Notes have been revised
6	Rob McKeown	03-2300		Overhead - Minimum Clearances Buildings and Permanent Structures	03	Revised	Revised note to reflect new standard 03-2310
7	Rob McKeown	03-2310		Overhead - Swing Allowance for Conductors	03	New	New
8	Rob McKeown	03-2700		Overhead Minimum Clearance - Between Service Mast and Readily Accessible Surfaces	03	New	New standard to show clearances for readily accessible surfaces
9	James Daniel	04-4100		POLE LOCATION GUIDELINES	04	Revised	Revised clearances
10	James Daniel	04-4200		Pole And Pole Settings - Gurd	04	Revised	Revised clearances
11	Rob McKeown	05-0000		Index of Standards	05	Revised	Added 05-2180, Rev 13
12	Rob McKeown	05-0010		Introduction	05	Revised	Revised Notes
13	Rob McKeown	05-1580		3-Phase Double Dead-End or Transition Between Bare and Treeproof Horizontal Configuration	05	Revised	Revision made to notes
14	Rob McKeown	05-1880		DOUBLE 3-PHASE DOUBLE DEAD-END OR TRANSITION BETWEEN BARE AND TREEPROOF VERTICAL CONFIGURATION	05	Revised	Added correct (hidden) part to drawing
15	Rob McKeown	05-2180		4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Horizontal Run-Off From 3-Phase Horizontal	05	New	Created standard to show 3 ph horizontal run off from 3 ph horizontal (NEW)
16	Rob McKeown	07-0000		Index Of Standards	07	Revised	**Revised To Remove Standards**
17	Rob McKeown	07-1200		ANCHOR SELECTION HOLDING CAPACITIES FOR VARIOUS SOIL CLASSES	07	Revised	Revised Notes

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #47

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
18	Rob McKeown	07-2200		ANCHOR INSTALLATION EXPANSION ANCHOR CLASS 8 SOIL TYPE	07	Revised	Revised Drawing
19	Rob McKeown	07-3100		GUY SELECTION	07	Obsolete	Remove from standards
20	Rob McKeown	07-3200		DETERMINE ULTIMATE LOAD AND GUY TENSION	07	Obsolete	Remove from standards
21	Rob McKeown	07-3300		BISECTOR CHART METHOD	07	Obsolete	Remove from standards
22	Rob McKeown	07-3400		LINE TERMINATION CHART METHOD	07	Obsolete	Remove from standards
23	Rob McKeown	07-3500		GUYING - Typical Guying Arrangements	07	Revised	Revised description under the 'Type of Guy' column
24	Rob McKeown	07-4000		GUY COMPONENTS	07	Revised	Revised Notes
25	Rob McKeown	07-4250		Guying Installation Procedure Strut Guy	07	Revised	Revised Notes
26	IGOR SIMONOV	09-9500		1-Phase Transformers	09	Revised	BOM CHANGED
27	IGOR SIMONOV	09-9510		1-Phase Transformers - Dead-End Configuration	09	Revised	BOM CHANGED
28	IGOR SIMONOV	09-9600		3-Phase Transformers - Overbuild Only	09	Revised	BOM CHANGED
29	IGOR SIMONOV	09-9610		3-Phase Transformers - Dead-End Configuration	09	Revised	BOM CHANGED
30	Emma Halilovic	10-1300		Disconnect in-Line Switches All Voltages	10	Revised	Revise
31	EMMA HALILOVIC	10-2400		3-PHASE LOAD INTERRUPTER SWITCH	10	Revised	Changes of bill of material
32	EMMA HALILOVIC	10-2600		Manually-Operated 13.8kV and 27.6kV Tier Outboard Type	10	Revised	Revised Drawing and BOM
33	EMMA HALILOVIC	10-2810		Three Phase Load Interpuder mterup	10	Revised	Revised Drawing and BOM
34	EMMA HALILOVIC	10-3000		Scada-Operated 13.8 kV & 27.6 kV Feeder Riser Using Upright Type Switch	10	Revised	Revised Drawing and BOM
35	EMMA HALILOVIC	10-3500		SCADA-Operated 13.8kV & 27.6kV Tier Outboard Type	10	Revised	Revised Drawing and BOM

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #47

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
36	EMMA HALILOVIC	10-3510		SCADA Operated 13.8kV & 27.6kV Tier Outboard Type (Feeder Tie)	10	Revised	Revised Drawing and BOM
37	EMMA HALILOVIC	10-3610		SCADA-Operated 13.8kV & 27.6kV Upright Type	10	Revised	Revised Drawing and BOM
38	Rob McKeown	11-3170		Multiplexed Secondary Bus Dead-End on TTC Steel Pole	11	Revised	Revised drawing to show neutral
39	Rob McKeown	11-3180		Multiplexed Secondary Bus Dead-End On Concrete or Wood Pole	11	Revised	Revised drawing to show neutral
40	Rob McKeown	11-5500		120 V CONNECTION FOR UNMETERED SERVICES STAND ALONE STRUCTURES	11	Revised	Revised standard
41	Rob McKeown	12-0000		Index of Standards	12	Revised	Revised standard
42	Rob McKeown	12-1200		Riser Installaion Details - Cable Guard or Pipe	12	Revised	Revised note 1
43	Rob McKeown	12-3000		Primary Service Risers - Primary Drops and Connections For 1-Phase Service Riser	12	Revised	Drawing And Material Change
44	Rob McKeown	12-3100		Primary Service Risers - Primary Drops and Connections For 3-Phase Service Riser	12	Revised	Drawing And Material Change
45	Rob Mckeown John Hecimovic	12-3500		PRIMARY SERVICE RISERS - FUSED 3-PHASE WITH CLF 13.8kV & 27.6kV GRD Y	12	Revised	NEW REVISION OF AN OLD STANDARD THAT WAS OBSOLETE.
46	John Hecimovic	12-4000		PRIMARY FEEDER RISERS - FUSED 13.8kV & 27.6kV GRD Y	12	Revised	**Drawing And Material Change**
47	Benson Lo	13-7060		3 1-PHASE TRANSFORMER VAULT 27.6 Kv TYPICAL LAYOUT	13	Revised	**Note revision**
48	John Hecimovic	13-7200		GRD. Y VAULT - TYPICAL LAYOUT 27.6 Kv	13	Revised	Full Review and Evaluation
49	John Hecimovic	13-7500		3 1-PHASE TRANSFORMER VAULT 27.6 Kv CUSTOMER ROOM WITH SF6 SWITCHGEAR	13	Revised	Full Review and Evaluation
50	IGOR SIMONOV	14-3200		Padmount Transformers	14	Revised	**Note change**
51	IGOR SIMONOV	14-3300		Padmount Transformers	14	Revised	Note change
52	IGOR SIMONOV	14-3400		Padmount Transformers	14	Revised	**Note change**
53	IGOR SIMONOV	14-3500		Padmount Transformers	14	Revised	Note change

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #47

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
54	IGOR SIMONOV	14-3600		Installation - 27.6kV radial/Loop 3 - phase 27.6kV radial Loop System	14	Revised	Note 5 and material change
55	John Hecimovic	16-2350		UG Cables, Joints, Terminations and Connectors	16	Revised	drawing change
56	John Hecimovic	16-3700		UG Cables, Joints, Terminations and Connectors	16	Revised	drawing change
57	John Hecimovic	16-3940		UG Cables, Joints, Terminations and Connectors	16	Revised	drawing change
58	John Hecimovic	16-5200		UG Cables, Joints, Terminations and Connectors	16	Revised	Standard Change
59	Tarek Turk	16-6210		Cable Reel Data Cable And Wire Reel Chart	16	Revised	Data revision
60	JAMES DANIEL	17-2250		MINIMUM CLEARAN	17	Revised	Note change
61	JAMES DANIEL	17-2310		Secondary - Outdoor Service Pedestal, Single Phase, Up to 200A	17	Revised	Full Review and Evaluation
62	JAMES DANIEL	17-4600		PRIMARY METERING - 27.6 kV, 600 A - 3-PHASE 4 WIRE TYPICAL OUTDOOR INSTALLATION	17	Revised	Revised Notes
63	EMMA HALILOVIC	18-5000		Guard Post Grounding Detail	18	Revised	Revised Notes
64	JAMES DANIEL	21-2100		OVERHEAD STENCILING - POLE NUMBERING	21	Revised	Revised Notes
65	JAMES DANIEL	21-2200		PRIMARY SERVICE RISER - FUSED 1 PHASE BACK TO BACK	21	Revised	Revised Notes
66	JAMES DANIEL	21-2400		IN-LINE SWITCH NUMBERING	21	Revised	Revised Notes
67	JAMES DANIEL	21-2500		COMMUNICATION AND CONTROL UNIT NUMBERING	21	Revised	Revised Notes
68	JAMES DANIEL	21-2700		REPEATER RADIO NUMBERING - (FOR FEEDER AUTOMATION)	21	Revised	Revised Notes
69	JAMES DANIEL	21-3200		UNDERGROUND STENCILING - TAP BOX/ TAP BOX VAULT STENCILING	21	Revised	Revised Notes
70	JAMES DANIEL	21-3300		UNDERGROUND STENCILING - 3-PHASE PRIMARY METERING CABINET	21	Revised	Revised Notes
71	JAMES DANIEL	21-3500		3-PHASE PAD-MOUNTED TRANSFORMER	21	Revised	Revised Notes

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #47

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
72	JAMES DANIEL	21-3700		UNDERGROUND STENCILING - CABLE CHAMBER STENCILING	21	Revised	Revised Notes
	IGOR SIMONOV	21-3900		Underground Stenciling	21	Revised	changed drawing on page 3
73	JAMES DANIEL	21-4300		UNDERGROUND STENCILING - CABLE CHAMBER STENCILING	21	Revised	Revised Notes
74	Rob McKeown	21-4700		UNDERGROUND STENCILING - SECONDARY CABLE LABELLING	21	Revised	Revised Notes
75	Rob McKeown	23-0000		INDEX OF STANDARDS	23	Revsed	Revised to add new standard
76	Rob McKeown	23-1260		FOREIGN ATTACHMENTS	23	New	New Standard
77	IGOR SIMONOV	24-1400		Underground fusing 27.6 kV transformer in vault	24	Revised	revised notes
78	IGOR SIMONOV	24-1600		Underground fusing 13.8 kV URD system	24	Revised	revised notes
79	IGOR SIMONOV	24-2000		Underground fusing molded current-limiting fuse	24	Revised	revised notes
80	James Daniel	27-8000		Legend/Drafting Symbols	27	Revised	Page 2 Section of standards revised
81	EMMA HALILOVIC	30-0000		INDEX OF STANDARDS	30	Revised	Revised to remove Standards
82	EMMA HALILOVIC	30-3250		Installation Detail light-trespass Sheilds	30	Obsolete	obsoleted
83	EMMA HALILOVIC	30-3300		Installation Detail Lamp Holder Ajustment in the universal Luminaire	30	Obsolete	Standard obsoleted
84	James Daniel	30-3570		Installation of Sidemounted Plate	30	Revised	Material Change
85	IGOR SIMONOV	30-3810		Typical in-line Fuse Installation	30	Obsolete	standard obsoleted
86	James Daniel	30-4100		Concrete Pole 25' & 30' With Universal Luminaire	30	Revised	Drawing revised and added note 6
87	James Daniel	30-7160		DECORATIVE STREET LIGHTING POLE HISTORICAL OLD FOREST HILL	30	Revised	Drawing revised
88	James Daniel	30-9780		Reinforced Sidewalk Bay	30	Revised	Drawing revised

DISTRIBUTION CONSTRUCTION STANDARDS

TORONTO HYDRO

STANDARDS REVISION #47

#	REQUESTER	STANDARDS No	REPLACES	STANDARDS NAME	STANDARDS SECTION	NEW/REVISED/ OBSOLETE	COMMENTS
89	James Daniel	30-9800		Civil Construction Reinforced Bay	30	Revised	Drawing revised
90	James Daniel	30-9820		Reinforced Side Walk Bay	30	Revised	Drawing revised
91	James Daniel	31-0100		Underground Clearances	31	Revised	Notes have been revised
92	James Daniel	31-1400		Duct Sealant Installation	31	New	New
93	James Daniel	31-2120		Cable Chambers Lid Placement	31	Revised	Revised to a new construction standard from the old format
94	James Daniel	31-4030		Three Phase Precast Pad-Mount 1830 mm x 1830 mm x 1220 mm	31	Revised	Revised measurement
95	James Daniel	31-4080		Padmounts Guard Posts(Bollards	31	Revised	Revise notes
96	James Daniel	31-5100		Vaults Precast Concrete	31	Revised	Revised Measurements
97	James Daniel	31-5190		VAULT 1 - 2000 kVA NETWORK VAULT 3000 mm (10'-0") X 4600 mm (15'-0") X 3660 mm (12'-0") HEAD ROOM	31	Revised	Revised measurement
98	James Daniel	31-7100		DRAINING STRUCTURES	31	Revised	Revised to a new construction standard from the old format
99	James Daniel	31-8320		LADDERWAY GRID FRAME FOR TRANSFORMER VAULT	31	Revised	Revised measurement and fonts
100	James Daniel	31-8390		Vault Transformer Vault Ladder	31	Revised	Revised measurement and fonts
101	James Daniel	31-8560		Material Fabrication - Ladderway Intake Vent Frame	31	Revised	Revised measurement and fonts
102	Kalyan Sarkar	70-10		Underground Secondary - Straight Joint Hand Taping Method 600 V and Below, 1 Conductor	70	New	New standard made for reactive maintenance for Hand Taping Method

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #48

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
1	03	03-2000	Clearances	Standard Attachment Points	Revised	7	Request to reduce clearances for overhead secondary's and primary
2	05	05-1340	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Vertical Configuration Angles 0 to 45 degrees	Revised	2	Revised location of ground rods from inside to outside with rods connected to form a loop - Added notes 1 to 4 and 6 - Added missing items 7, 10 to 13 in BOM
3	05	05-1420	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Dead-end Horizontal Configuration Angles 61 to 90 degrees	Revised	2	Initiator requires re-configuration for clearances of overhead back to back crossarm configuration
4	05	05-1820	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary Double 3-Phase Double Dead-End 90 Degrees	Revised	2	Provides more working clearance and better direction to construction crews.
5	05	05-1840	Pole Framing	4.16 to 276 kV Treeproof and Bare Primary Double 3-Phase Vertical Configuration 1 Tangent Circuit and 1 Dead-end Circuit	Revised	2	Dimensions added on the Drawing
6	05	05-2170	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Horizontal Run-Off From 3-Phase Halo	Revised	2	Centre phase jumper moved to the opposite side of the pole.
7	05	05-2420	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary 3-Phase Double Circuit Run-Offs from 3-Phase Double Circuit Vertical Configuration	Revised	2	Revised standard to show alternate installation for permutation B.
8	07	07-1200	Anchoring and Guying	Anchor Selection Ultimate Holding Strength Capacities Under Various Soil Classes	Revised	4	Wording Revised and conversion from mm to inches corrected.
9	07	07-2600	Anchoring and Guying	Expanding Pole Key Anchor Class 5 to 8 Soil Types	Revised	2	Spud Bar option added and notes Revised accordingly
10	07	07-3000	Anchoring and Guying	General Information	Revised	6	Changes made to drawing and notes to supplement engineering bulletin
11	07	07-3600	Anchoring and Guying	Location of Guy Insulator	Revised	2	Changes made to drawing and notes to supplement engineering bulletin
12	07	07-5100	Anchoring and Guying	Down Guy - One on Concrete, Wood or Steel Pole	Revised	5	Changes made to drawing and notes to supplement engineering bulletin
13	07	07-5110	Anchoring and Guying	Down Guy - One on Concrete or Wood Pole Using Insulator Rod(s)	Revised	4	Changes made to drawing and notes to supplement engineering bulletin
14	07	07-5160	Anchoring and Guying	Down Guy - One on Concrete or Wood Pole Using Insulator Rods on Armless Construction	Revised	5	Changes made to drawing and notes to supplement engineering bulletin
15	07	07-5170	Anchoring and Guying	V - Guying on Concrete or Wood Pole Using Insulator Rods on Armless Construction	Revised	1	Changes made to drawing and notes to supplement engineering bulletin
16	07	07-5200	Anchoring and Guying	Strut Guy - One On Concrete, Wood or Steel Pole	Revised	6	Changes made to drawing and notes to supplement engineering bulletin
17	07	07-5220	Anchoring and Guying	Strut Guys-Two On Concrete or Wood Pole Using Insulator Rod(s)	Revised	6	Changes made to drawing and notes to supplement engineering bulletin
18	07	07-5230	Anchoring and Guying	Strut Guys-One On Concrete or Wood Pole Using Insulator Rod(s)	Revised	1	Changes made to drawing and notes to supplement engineering bulletin
19	07	07-5240	Anchoring and Guying	Strut Guy-Two on Cedar Or Concrete Pole Using Insulator Rod	Revised	1	Changes made to drawing and notes to supplement engineering bulletin
20	07	07-5250	Anchoring and Guying	Strut Guys - Three on Concrete or Wood Pole Using Insulator Rod(s)	Revised	1	Changes made to drawing and notes to supplement engineering bulletin
21	07	07-5340	Anchoring and Guying	Span & Strut Guy - One On Concrete, Wood or Steel Pole	Revised	6	Changes made to drawing and notes to supplement engineering bulletin
22	07	07-5350	Anchoring and Guying	Span & Strut Guy - One On Concrete, Wood or Steel Pole Using Insulator Rod	Revised	6	Changes made to drawing and notes to supplement engineering bulletin
23	07	07-5370	Anchoring and Guying	Span & Strut Guy - Two On Concrete, Wood or Steel Pole With One Span Guy Using Insulator Rod	Revised	7	Changes made to drawing and notes to supplement engineering bulletin
24	07	07-5380	Anchoring and Guying	Span & Strut Guys - Two On Concrete or Wood Pole Using Insulator Rod	Revised	4	Changes made to drawing and notes to supplement engineering bulletin

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #48

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
25	07	07-5300	Anchoring and Guying	Span & Down Guy - One on Concrete, Wood or Steel Pole	Revised	5	Changes made to drawing and notes to supplement engineering bulletin
26	07	07-5310	Anchoring and Guying	Span & Down Guy - One on Concrete, Wood or Steel Pole Using Insulator Rod(s)	Revised	5	Changes made to drawing and notes to supplement engineering bulletin
27	07	07-5320	Anchoring and Guying	Span & Down Guy - Two on Concrete, Wood or Steel Pole	Revised	6	Changes made to drawing and notes to supplement engineering bulletin
28	07	07-5400	Anchoring and Guying	Storm Guy on Concrete Or Wood Pole	Revised	4	Changes made to drawing and notes to supplement engineering bulletin
29	07	07-5500	Anchoring and Guying	Span Guy - One On Concrete, Wood or Steel Pole	Revised	5	Changes made to drawing and notes to supplement engineering bulletin
30	08	08-0000	INDEX	INDEX of Standards	Revised	6	Revised to add 2 new standards
31	08	08-3450	Overhead Conductors and Connectors	Bolted Tap - Box Application and Selection Table	Revised	2	Identified requirement for more equipment, Revised table to include additional material
32	08	08-3620	Overhead Conductors and Connectors	Overhead Connectors - Pulling Grips Application and Selection Table	Revised	1	Revised selection table to show new conductor selection list. Notes were also Revised to compliment new selection table.
33	08	08-3630	Overhead Conductors and Connectors	Overhead Connectors - Temporary Pulling Grips Application and Selection Table	New	0	CRF was created by field rep to have standards identify correct pulling grip
34	09	09-1300	Overhead Transformers	General Information Installation	Revised	5	Review the submitted drawing and update the standards so they are constant
35	09	09-3500	Overhead Transformer	Wild Life guard Details	Revised	3	Wild life guard change to new design as the existing one did not fit correctly for 27.6 transformers
36	09	09-9500	overhead transformers	1 Phase Transformer	Revised	5	Update standard to reflect and show the standard off installation dimensions and consider changing
37	09	09-9510	overhead transformers	Primary drop leads	Revised	2	Update standard to reflect and show the standard off installation dimensions and consider changing
38	09	09-9600	overhead transformer	Primary drop leads	Revised	5	Update standard to reflect and show the standard off installation dimensions and consider changing
39	10	10-3700	Overhead Switches	Communication and Control Unit (CCU) SCADA and Feeder Automation	Revised	11	Revised BOM to include padlock and antenna cable for SD9 radio
40	10	10-3800	Overhead Switches	3-Phase primary	Revised	5	CRF-2014-0112. Revised standard to include riser notes , updated BOM to meet the April 2016 open bin material
41	11	11-3110	O/H Secondary & Primary Services	Multiplexed Secondary Bus Break On Concrete or Wood Pole Or Midspan	Revised	3	Midspan bus break option added to the drawing, Revised BOM and BOM Legend
42	11	11-3210	Overhead Primary & Secondary Service	Multiplexed Secondary Bus: Service Taps 120/240V at Pole	Revised	4	Storm safe grip was introduced for the purpose of having the service break from the line side and not the house side and also preventing the customer electrical stack from being pulled down
43	11	11-3250	Overhead Primary & Secondary Service	Multiplexed Secondary Bus: Service Taps 120/240V at Mid-Span	Revised	4	Storm safe grip was introduced for the purpose of having the service break from the line side and not the house side and also preventing the customer electrical stack from being pulled down
44	11	11-3300	Overhead Primary & Secondary Service	Multiplexed Secondary Bus: Service Taps 120/208V at Pole	Revised	3	Storm safe grip was introduced for the purpose of having the service break from the line side and not the house side and also preventing the customer electrical stack from being pulled down
45	11	11-3350	Overhead Primary & Secondary Service	Multiplexed Secondary Bus: Service Taps 120/208V at Mid-Span	Revised	3	Storm safe grip was introduced for the purpose of having the service break from the line side and not the house side and also preventing the customer electrical stack from being pulled down
46	11	11-3400	Overhead Primary & Secondary Service	Multiplexed Secondary Bus: Service Taps 600 V or 347/600V at Pole	Revised	3	Storm safe grip was introduced for the purpose of having the service break from the line side and not the house side and also preventing the customer electrical stack from being pulled down

DISTRIBUTION CONSTRUCTION STANDARDS

REVISION #48

53	11	11-4600	Overhead Primary & Secondary Service	Open Secondary Bus Open Secondary Bus 120/240 V or	Revised	3	e service venting the
54	11	11-4650	Overhead Primary & Secondary Service	Open Secondary Bus Open Secondary Bus 120/240 V at Mid-Span	Revised	4	e service venting the
55	11	11-5200		120 V CONNECTION FOR UNMETERED SERVICES STAND ALONE STRUCTURES	Revised	6	

DISTRIBUTION CONSTRUCTION STANDARDS

REVISION #48

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
67	13	13-4100	UG Transformer &switchgear	13.8kV Radial System 600 A Secondary Manual Switch ATS Replacement	Revised	1	to revise standard to reflect changes required for switch ratings
68	16	16-4180	UG Cables Joints Terminations & Connections	600 A Deadbreak Connectors 15 kV, 1 Cond.	Revised	3	Added notes to include stock code bushing insert torque tool that are available.
69	16	16-4220	UG Cables Joints Terminations & Connections	200 A Loadbreak Connectors 15 kV, 1 Cond.	Revised	3	Added notes to include stock code bushing insert torque tool that are available.
70	16	16-4260	UG Cables Joints Terminations & Connections	600 A Deadbreak Connectors 28 kV, 1 Cond.	Revised	2	Added notes to include stock code bushing insert torque tool that are available.
71	16	16-4300	UG Cables Joints Terminations & Connections	200 A Loadbreak Connectors 28 kV, 1 Cond.	Revised	3	Added notes to include stock code bushing insert torque tool that are available.
72	16	16-4640	UG Cables, Joints/Terminations and Connectors	Hand Taped Splice, 5 kV, 1 Conductor TRXLPE to RILC	Obsolete	0	Standard to be used for reactive construction. Moved to section 70-8 (Reactive Maintenance).
73	16	16-4660	UG Cables, Joints/Terminations and Connectors	Hand Taped Splice, 5 kV, 1 Conductor TRXLPE to RILC	Obsolete	2	Standard to be used for reactive construction. Moved to section 70-8 (Reactive Maintenance).
74	16	16-6000	UG Cables, Joints, Terminations and Connectors	SECONDARY TERMINATIONS SUBMERSIBLE TRANSFORMER TERMINAL CLUSTER 600 V OR BELOW	Revised	6	BOM and drawing has been Revised to identify changes identified by initiator
75	16	16-6020	UG Cables, Joints, Terminations and Connectors	SECONDARY TERMINATIONS 1 PH SUBMERSIBLE AND 1 PH PADMOUNTED TRANSFORMERS	Revised	1	BOM and drawing has been Revised to identify changes identified by initiator
76	17	17-0000	Revenue Metering	Index	Revised	11	Revised Index to add standards 17-8210 and 17-8220.
77	17	17-8210	Revenue Metering	Pole Mounted Cellular Gatekeeper - Fed From Overhead Secondary Main	New	0	Standard was required for future installations as required
78	17	17-8220	Revenue Metering	Pole Mounted Cellular Gatekeeper - Fed From Underground Secondary Main	New	0	Standard was required for future installations as required
79	18	18-3200	Grounding	Overhead System Cable Guard or Galvanized Pipe riser For duct Bend	Revised	3	1)Separated grounding detail of cable guard from bonding detail of GI pipe as per Std 12-1200 2)Added depth of rod 3)Added Details B and D to show installation of 3-phase cable guards 4)Changed Detail 'A' to 'C' to show installation on cable guard5)Revised BOM Legend 'A' and 'B' to apply to Rigid PVC Type only (instead of GI Pipe) 6)Corrected quantity of material required 7)Revised BOM to specify ½" bolt instead of 3/8" for ground wire connection to cable guard
80	18	18-3250	Grounding	Overhead System Cable Guard For Direct Buried Cable	Revised	7	1) Updated cable guard installation as per standard 12-1200 2)Revised dimension for depth of ground rod installation to include max 3)Revised Note 1 from specifying requirements for cable guard installation to referencing applicable standard 12-1200 4)Deleted Note 2 which specified situations where ground rod is not required. As per Section 18, ground rods are required for riser terminations 5)Revised Detail 'A' to show installation on cable guard 6)Added Detail 'B' to show installation of 3-phase cable guards
81	18	18-5400	Grounding	Splice Chamber	Revised	3	Revised standard to include ground loop external to the pad
82	21	21-1100	Overhead and Underground Stenciling	Stenciling Material	Revised	5	CRF-2016-0021 has been completed and the standard 21-1100 has been Revised and stamped.
83	21	21-2100	Overhead and Underground Stenciling	Overhead Stenciling Pole Numbering	Revised	4	Clarify stenciling as per CRF
84	21	21-2110	Overhead and Underground Stenciling	Phase Configuration Identification	Revised	1	To provide better direction to construction crews in the field
85	21	21-3400	Overhead and Underground Stenciling	1-Phase Low Profile Pad-Mounted Transformer	Revised	2	Revised as per SMT to show 1" elbow numbers inside the 3" phase markers. Notes were also Revised to aid in identifying associated standards and to reflect changes made to phase marker detail.
86	21	21-3500	Overhead and Underground Stenciling	3-Phase Pad-Mounted Transformer	Revised	3	Revised as per SMT to show 1" elbow numbers inside the 3" phase markers. Notes were also Revised to aid in identifying associated standards and to reflect changes made to phase marker detail.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #48

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
87	21	21-4200	Overhead and Underground Stenciling	Underground Stencilling Primary Cable Labeling	Revised	1	Revisions have been made as per CRF-2016-0076, however the standard is still being Revised as per CRF-2015-0285 for NPI
88	27	27-1000	Legend/Drafting Symbols	switches and fusing	Revised	3	Designer changed cell library location. We have to revise standard accordingly
89	27	27-2000	Legend/Drafting Symbols	Transformer	Revised	3	Designer changed cell library location. We have to revise standard accordingly
90	27	27-3000	Legend/Drafting Symbols	conductors and connectors	Revised	2	Designer changed cell library location. We have to revise standard accordingly
91	27	27-4100	Legend/Drafting Symbols	civil structures	Revised	2	Designer changed cell library location. We have to revise standard accordingly
92	27	27-4200	Legend/Drafting Symbols	civil landbase	Revised	2	Designer changed cell library location. We have to revise standard accordingly
93	27	27-5000	Legend/Drafting Symbols	street lighting	Revised	2	Designer changed cell library location. We have to revise standard accordingly
94	27	27-6000	Legend/Drafting Symbols	grid solutions	Revised	2	Designer changed cell library location. We have to revise standard accordingly
95	27	27-7000	Legend/Drafting Symbols	metering and miscellaneous	Revised	2	Designer changed cell library location. We have to revise standard accordingly
96	27	27-8000	Legend/Drafting Symbols	assemblies	Revised	3	Designer changed cell library location. We have to revise standard accordingly
97	28	28-0400	Distribution Construction Standard	Concrete Pole Ground Bar Connection Details	Revised	2	Added drawing, Revised notes and BOM
98	31	31-0000	INDEX	INDEX	Revised	18	Update index as there are 1 standard new and 2 obsoleted standards from this section and relocated to section 70 for reactive maintenance
99	31	31-0100	Civil Construction Standard	Underground Clearances	Revised	6	Please close the CRF-2016-0083. Soft copy of Revised std. has been placed in Projectwise
100	31	31-0700	Civil Construction	Shoring / Excavation In the Vicinity Of Toronto Hydro Underground Plant	NEW	0	Engineer initiative for Utility Circulation for shoring guidelines
101	31	31-1220	Civil Construction	Installation of Bends on Pole	Revised	10	Drawing added for new GI Bend, Revised notes
102	31	31-3140	Civil Construction	handwell with polymer concrete lid	Revised	3	Revised drawing with details to represent consistency with the manufacturer drawing.
103	31	31-5100	Civil Construction	Precast Concrete Two Pieces Submersible vault 940 mm (3'-1") x 1960 mm (6'-5") x .1830 mm (6'-0")	Revised	12	Revised Notes, BOM, Installation, and Drawing to show drain from submersible vault to a gravel sump pit when used as splice vault
104	31	31-8120	Civil Construction	100 mm (4") galvanized iron bend	Obsolete	1	
105	57	57-0000	Station Equipment	Index of Standards	Revised	1	Addition of a standard to the section.
106	57	57-6000	Station Equipment	Tools For DST	New	0	New STD. for Station Technologist
105	70	70-4640	REACTIVE MAINTENANCE	PRIMARY STRAIGHT JOINT	RE LOCATED	1	TO BE USED FOR MAINTENANCE ONLY AS NO LONGER USE AS A STANDARD AND ONLY TO BE USED AS MAINTENANCE
106	70	70-4660	REACTIVE MAINTENANCE	PRIMARY STRAIGHT JOINT	RE LOCATED	1	TO BE USED FOR MAINTENANCE ONLY AS NO LONGER USE AS A STANDARD AND ONLY TO BE USED AS MAINTENANCE

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #49

4	05	05-0000					
5	05	05-1130	Pole Framing	4.16 to 27.6 kV Treeproof and bare Primary mid-span opener.	REVISED	1	about ng LC# ard. ails"
6	05	05-1140	Pole Framing	4.16 To 27.6 kV Treeproof and Bare Primary 1-Phase Double Dead-End or Transition between Bare and Treeproof	REVISED	3	ing OM
7	05	05-1280	Pole Framing	horizontal configuration 0 to 3 degrees.	REVISED	2	
8	05	05-1600			REVISED	3	
9	05	05-1740			REVISED	2	
					REVISED	2	
11	05	05-2020			REVISED	1	
12	05	05-1770			NEW	0	
13	06	06-6300					

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DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #49

14	08	08-3630			REVISED	1	
16	09	09-8400					
18	09	09-8800	Overhead Transformer	3- Phase Construction 16000/27600 - 120/208 V - 50 kVA	REVISED	14	ew t a
19	09	09-9100	Overhead Transformer	3- Phase Construction 2400/4160 - 347/600 V WYE 100 & 167 kVA	REVISED	14	ew t a
20	09	[illegible]	Overhead Transformer	WYE all kVA Sizes	REVISED	14	
22	10	10-1600			REVISED	3	
23	10	10-1640			REVISED	2	
24	10	10-1660			REVISED	4	
25	10	10-1710			REVISED	1	
26	10	10-1730			REVISED	1	
27	10	10-2600			REVISED	9	
28	10	10-3500			REVISED	12	

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #49

29	10	10-3510			REVISED	4	
30	11	11-0000					
31	11	11-3810			New	0	
32	13	13-0000					
33	13	13-1000	UG Transformer and Swtichgears	Underground Transformers General	REVISED	2	
34	13	13-5000	U/G Transformer and Switchgears	13.8 kV network Systems General Information	REVISED	4	
35	13	13-5030	U/G Transformer and Switchgears	Innards For Network Protectors	NEW	0	
					REVISED	1	
					REVISED	12	
38	13	13-7810			REVISED	5	
41	14	14-3300					

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #49

43	14	14-3500					
45	17	17-9500			REVISED	3	
46	21	21-1100	Overhead and Underground Stenciling	General information Stenciling Information	Revised	6	2)
47	21	21-2100	Overhead and Underground Stenciling	Overhead stenciling Pole numbering	Revised	5	s. label as
48	21	21-3400	Overhead and Underground Stenciling	1-Phase Low Profile Pad-mounted Transformer	Revised	[illegible]	
49	21	21-3500					
50	21	21-3800			Revised	2	
51	23	23-0000					
52	23	23-1020			REVISED	4	
					REVISED	4	
54	23	23-1100					

55	23	23-1130			REVISED	2	
56	23	23-1140			OBSOLETE	0	
58	24	24-1300					
59	24	24-1400	Fusing	Underground fusing 27.6 kV transformer in vault	Revised	4	ınged
60	28	28-0000	O/H and U/G Material Fabrications	Index of Standards	REVISED	4	ew
61	[illegible]	[illegible]	O/H and U/G Material Fabrications	Mount	[illegible]	[illegible]	
63							
65							
67							

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DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #49

69							
71							
72	28	28-0414	O/H and U/G Material Fabrications	Concrete Pole 16.76 m (55’-0”) Class G Direct Buried	REVISED	3	poles in ole,
73	28	28-0415	O/H and U/G Material Fabrications	Concrete Pole 16.76 m (55’-0”) Class H Direct Buried	REVISED	2	poles in ole,
[illegible]	[illegible]	[illegible]	O/H and U/G Material Fabrications	Buried	[illegible]	[illegible]	
75							
					NEW		
77					NEW		
					NEW		

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #49

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
81	30	30-1120	Street Lighting	Acorn Luminaire Selection Table	NEW	0	New standard to include details of the Acorn Luminaires including photometric file that is required for design.
82	30	30-1300	Street Lighting	Secondary Bus Cables Selection Table	NEW	1	Revised colour of cable jacket. Added O/H cable and underground #2 AWG street lighting and expressway cables.
83	30	30-1600	Street Lighting	Street Light Brackets - Details	NEW	0	New standard to show various street light brackets required for Cobra Head and Acorn Luminaires.
84	30	30-3600	Street Lighting	Overhead 120 V Supply to Pole-Mounted Luminaire	NEW	0	New standard to show various street light brackets required for Cobra Head and Acorn Luminaires.
85	30	30-3700	Street Lighting	Underground 120 V Supply to Pole-Mounted Luminaire at the First Pole with In-Pole Circuit Breaker	REVISED	3	Revised notes, wiring connection and BOM. Replaced split bolt with ground connector. Revised stock code for ground rod to #6 AWG wire connection. Added ground rod and installation details. Revised circuit breaker details as per shop drawing.
86	30	30-3730	Street Lighting	120 V Service Entrance without Circuit Breaker 1-Phase In-Pole Type at the First Pole	OBSOLETE	0	Standard obsoleted. Refer to standard 30-3800.
87	30	30-3800	Street Lighting	Underground 120 V Supply to Pole-Mounted Luminaire	REVISED	3	Removed details of U/G supply duct into pole aperture. Revised notes and BOM. Replaced split bolt with ground connector. Added BOM legend for installation with and without ground.
88	30	30-3820	Street Lighting	Underground Supply Duct into pole Aperture	NEW	0	New civil standard. To clarify duct structure going into pole for streetlight service
89	30	30-4100	Street Lighting	Concrete Pole with Acorn Luminaire	REVISED	8	Revised standard title, edited the note, added pole base detail, and changed the BMO and BOM Legend to show the four street lighting pole heights (25', 30', 35', 40')
90	30	30-4110	Street Lighting	Acorn Luminaire with Bracket Typical Installation on Concrete, Wood or Steel Pole	REVISED	4	BOM's in street lighting had many permutations causing the size of the BOM to span over a few pages. This standard has been revised to show various installations on one standard instead of having 3 standards to display the installations.
91	30	30-4120	Street Lighting	Roadway Types - Universal Luminaire on a Cedar Pole	OBSOLETE	3	Standard obsoleted. BOM's in street lighting had many permutations causing the size of the BOM to span over a few pages. This standard has been Obsolete since the information depicted within this standard will now be covered in standard 30-4110.
92	30	30-4130	Street Lighting	Roadway Types - Universal Luminaire on a Steel Pole	OBSOLETE	4	Standard obsoleted.BOM's in street lighting had many permutations causing the size of the BOM to span over a few pages. This standard has been Obsolete since the information depicted within this standard will now be covered in standard 30-4110.

TORONTO HYDRO

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #49

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
93	30	30-4210	Street Lighting	Aluminum Pole with Cobra Head Luminaire	REVISED	7	Added bracket installation details. Revised BOM legend and BOM.
94	30	30-4220	Street Lighting	Concrete Pole with Cobra Head Luminaire	REVISED	8	Added concrete pole base detail. Added 25' Class C base-mounted pole. Revised BOM legend and BOM.
95	30	30-4240	Street Lighting	Cobra Head Luminaire with Bracket Typical Installation on Concrete, Wood, or Steel Pole	REVISED	3	BOM's in street lighting had many permutations causing the size of the BOM to span over a few pages. This standard has been revised to show various installations on one standard instead of having 3 standards to display the installations.
96	30	30-4250	Street Lighting	Roadway Types - Cobra Head Luminaire on a Cedar Pole	OBSOLETE	3	Standard obsoleted. BOM's in street lighting had many permutations causing the size of the BOM to span over a few pages. This standard has been Obsolete since the information depicted within this standard will now be shown in 30-4240.
97	30	30-4260	Street Lighting	Roadway Types - Cobra Head Luminaire on a Steel Pole	OBSOLETE	2	Standard obsoleted. BOM's in street lighting had many permutations causing the size of the BOM to span over a few pages. This standard has been Obsolete since the information depicted within this standard will now be shown in 30-4240.
98	30	30-4290	Street Lighting	Composite Pole 30' with Universal luminaire	OBSOLETE	1	Standard has been OBSOLETED.
99	30	30-9100	Street Lighting	Laneway Lighting Bracket Acorn or Cobra Head Luminaire on Wood Pole	REVISED	3	Deleted luminaire and electrical installation details from the standard. Added bracket details.
100	30	30-9500	Street Lighting	Design Criteria Concrete Foundations for Base Mounted Street Lighting Poles	OBSOLETE	3	Standard has been OBSOLETED. Some of the information was no longer required since it is part of legacy. The required information has been transferred to 30-9850.
101	30	30-9600	Street Lighting	Civil Construction - Concrete Foundation for Base Mounted - Aluminum Poles	OBSOLETE	3	Standard has been OBSOLETED.The details of concrete foundation in standard 30-9600 have been moved to standard 30-9820.
102	30	30-9840	Street Lighting	Reinforced Sidewalk Bays Concrete & Steel poles	OBSOLETE	3	Standard has been OBSOLETED.Required information has been added to 30-4100 and 30-4220.
103	30	30-9850	Street Lighting	Pole Anchors for Base-Mounted Poles	NEW	0	New standard.
104	31	31-1200	Civil Construction	Tunnelling Under TTC Tracks	REVISED	2	Added 6 new notes as identified by Triangles NOTE 6 into notes and specified the details of Section A-A.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #49

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised/ Obsolete	Revision number at date of issue	Revision Description
105	31	31-5000	Civil Construction	Sleeve-Lifting for Removable Concrete Slab	REVISED	2	Standard revised to Improve clarity on drawing and text. Adding "slab" on the concrete section view to allow user to determine which portion of the drawing is the slab material. Combined two of the comments on the section view.
106	31	31-7400	Civil Construction	Sewer Drain Connection From Cable Chamber or Transformer Vault	REVISED	1	Standard reviewed and BOM legend was added ,BOM added Note 2 added.
107	31	31-8470	Civil Construction	Sleeve-Lifting for Removable Concrete Slab	REVISED	2	Standard revised to Improve clarity on drawing and text. Adding "slab" on the concrete section view to allow user to determine which portion of the drawing is the slab material. Combined two of the comments on the section view.
108	34	34-0000	Engineering Information and References	Index of Standards	REVISED	4	New standards added to section 34, revision required Index has been revised to reflect new standards added to section 34-3200,34-3300 and 34-3400
109	34	34-1000	Engineering Information and References	Construction Deviation Guidelines	REVISED	3	To provide better examples, Revised points 1 and 3 in Non-Technical Deviation Examples section to fulfill CRF Request. These changes improve clarity for the examples.
110	34	34-3000	Engineering Information and References	Atypical Units Selection Table	NEW	0	This standard was created to help designers in the selection of Non-Construction Activity Units. As per the Asset Assembly Initiative
111	34	34-3200	Engineering Information and References	Additional Support Units	NEW	0	This standard was created to help designers in the selection of Non-Construction Activity Units. As per the Asset Assembly Initiative
112	34	34-3300	Engineering Information and References	Additional Resources	NEW	0	This standard was created to help designers in the selection of Non-Construction Activity Units. As per the Asset Assembly Initiative
113	34	34-3400	Engineering Information and References	Asset Removal Units Selection Table	NEW	0	This standard was created to help designers in the selection of Non-Construction Activity Units. As per the Asset Assembly Initiative

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #50

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
1	04	04-0000	Poles and Pole Settings	Index of Standards	REVISED	4	Addition of new standard 04-5610 to index.
2	04	04-1200	Poles and Pole Settings	General Information Concrete Poles	REVISED	2	Updated explanation of design specifications, pole heights, grounding, marking, and storage.
3	04	04-5200	Poles and Pole Settings	Cedar and Concrete Poles in Boulevard (hand Dig and Vacuum Truck)	REVISED	4	Revised concrete pole stock codes for poles having additional harmonized holes.
4	04	04-5500	Poles and Pole Settings	Cedar and Concrete Poles in Poor Soil	REVISED	3	Revised concrete pole stock codes for poles having additional harmonized holes.
5	04	04-5600	Poles and Pole Settings	Cedar and Concrete Poles in Slopes and Hillsides	REVISED	3	Revised concrete pole stock codes for poles having additional harmonized holes.
6	04	04-5610	Poles and Pole Settings	Pole Setting with Retaining Wall near Pole	NEW	0	New standard created for additional guidance to crews on installing poles near customer built retaining walls.
7	05	05-0010	Pole Framing	General Information Introduction	REVISED	4	Addition of note, "Additional materials such as stringing blocks and eye nuts (item I.D. 2520024) may be required for installation purposes.", to note 9.
8	05	05-1880	Pole Framing	Double 3-Phase Double Dead-end or Transition Between Bare And Treeproof Vertical Configuration	REVISED	4	Moved components such as washer, bolt, and cartridge to open bin. Revised quantity of insulators required.
9	07	07-4000	Anchoring and Guying	Guying - Guy Components	REVISED	3	Note 8 revised due to obsolete status of green guy guards.
10	07	07-5100	Anchoring and Guying	Down Guy - One on Concrete, Wood or Steel Pole	REVISED	6	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
11	07	07-5110	Anchoring and Guying	Down Guy - One on Concrete or Wood Pole Using Insulator Rod(s)	REVISED	5	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
12	07	07-5160	Anchoring and Guying	Down Guy - One on Concrete or Wood Pole Using Insulator Rods on Armless Construction	REVISED	6	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
13	07	07-5200	Anchoring and Guying	Strut Guy - One on Concrete, Wood or Steel Pole	REVISED	7	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
14	07	07-5220	Anchoring and Guying	Strut Guy - Two on Concrete or Wood Pole Using Insulator Rod(s)	REVISED	7	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
15	07	07-5230	Anchoring and Guying	Strut Guy - One on Concrete or Wood Pole Using Insulator Rod(s)	REVISED	2	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
16	07	07-5240	Anchoring and Guying	Strut Guy - Two on Cedar or Concrete Pole Using Insulator Rod	REVISED	2	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
17	07	07-5250	Anchoring and Guying	Strut Guy - Three on Concrete or Wood Pole Using Insulator Rod(s)	REVISED	2	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
18	07	07-5300	Anchoring and Guying	Span & Down Guy - One on Concrete, Wood or Steel Pole	REVISED	6	Green Guy Guard obsolete. BOM & BOM Legend have been revised.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #50

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
19	07	07-5310	Anchoring and Guying	Span & Down Guy - One on Concrete, Wood or Steel Pole Using Insulator Rod	REVISED	6	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
20	07	07-5320	Anchoring and Guying	Span & Down Guys - Two on Concrete, Wood or Steel Pole	REVISED	7	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
21	07	07-5340	Anchoring and Guying	Span & Strut Guy - One on Concrete, Wood or Steel Pole	REVISED	7	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
22	07	07-5350	Anchoring and Guying	Span & Strut Guy - One on Concrete, Wood or Steel Pole Using Insulator Rod	REVISED	7	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
23	07	07-5370	Anchoring and Guying	Span & Strut Guy - Two on Concrete, Wood or Steel Pole with One Span Guy Using Insulator Rod	REVISED	8	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
24	07	07-5380	Anchoring and Guying	Span & Strut Guy - Two on Concrete or Wood Pole Using Insulator Rod	REVISED	5	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
25	07	07-5400	Anchoring and Guying	Storm Guy on Concrete or Wood Pole	REVISED	5	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
26	10	10-3800	Overhead Switches	3-Phase Primary Drops All Voltages	REVISED	6	Revised quantity for BOM Item I.D. 7105235 (350 kcmil 61 STR WIRE)
27	13	13-0000	UG Tranformer & Switchgears	Index of Standards	REVISED	12	Obsoleted Std. 13-4010 from index.
28	13	13-4010	UG Tranformer & Switchgears	13.8 kV Radial System Above Grade Transformer Vault - Modular Switchgear Transformer Vault 8534 x 3048 (28' x 10')	OBSOLETE	N/A	Obsoleted 13-3010 and moved to 13-4020.
29	13	13-4020	UG Tranformer & Switchgears	13.8 kV Compact Radial Design	REVISED	8	Combined 13-4010 and 13-4020 into 13-4020. Changed material quantity in BOM. Changed the dimensions of the transformer on page 6.
30	14	14-3500	Padmounted Transformers	Installation - 27.6 kV 1-Phase Low Profile 27.6 kV system	REVISED	11	BOM revised due to Open Bin materials change.
31	15	15-1100	UG Secondary and Primary Services	Secondary Underground Services Cable Limiters	REVISED	4	Added associated standards 16-5300 and 16-5400 to BOM.
32	16	16-0000	UG Cable Joints Terminations & Connections	Index of Standard	REVISED	13	Added 16-1280 and 16-4320 to index.
33	16	16-1280	UG Cable Joints Terminations & Connections	Underground Primary Cable Testing	NEW	0	New standard created as instructions for proper operation and troubleshooting of new cable testing equipment.
34	16	16-4180	UG Cable Joints Terminations & Connections	600 A Deadbreak Connectors 15kV, 1 Conductor	REVISED	4	Addition of BOM legend F (copper 350 kcmil compressed). BOM item 8 (adapter cable deadbreak 350 kcmil) and item 9 (AL terminal lug for 15 kV 350 kcmil)
35	16	16-4260	UG Cable Joints Terminations & Connections	600 A Deadbreak Connectors 28kV, 1 Conductor	REVISED	3	Addition of BOM legend G (copper #4/0 compressed). BOM item 17 (adapter cable deadbreak #4/0) and item 18 (AL terminal lug for 28 kV #4/0).
36	16	16-4300	UG Cable Joints Terminations & Connections	200 A Loadbreak Connectors 28kV 1 Conductor	REVISED	4	Addition of BOM legend D (copper #4/0 compressed) and BOM item 3 (#4 cable elbow).

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #50

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
37	16	16-4320	UG Cable Joints Terminations & Connections	Primary - Cable Test Lead 15 kV or 28 kV For Cables Connected to Pad/Submersible Transformer and Switchgear	NEW	0	New standard for Cable Test Lead required for testing operations on cables connected to padmounted and submersible equipment.
38	16	16-5300	UG Cable Joints Terminations & Connections	Junction Connector and Fuse Limiter 600 V and Below	REVISED	4	Secondary Junction Connector Service Cable Std. 16-5400 added to associated standards.
39	21	21-0000	Overhead and Underground Stenciling	Index of Standards	REVISED	10	Updated title of Std. 21-2120.
40	21	21-4000	Overhead and Underground Stenciling	Underground Stenciling Network Equipment	NEW	0	New standard for network transformer nomenclature.
41	23	23-1200	Foreign Attachments	Overhead System - Pole Attachments Communication Cable Attachments	REVISED	2	Clause 6 revised to provide instruction on use of 'auxiliary eye'.
42	27	27-3000	Legend/Drafting Symbols	Conductors and Connectors	REVISED	3	New symbol created for Transition Splice.
43	27	27-4100	Legend/Drafting Symbols	Civil Structures	REVISED	3	New symbols created for Down guy and Strut Guy.
44	27	27-5000	Legend/Drafting Symbols	Street lighting	REVISED	3	New symbol created for transfer of street light bracket and luminaire.
45	27	27-8000	Legend/Drafting Symbols	Assemblies	REVISED	4	New symbols created for MINI Rupter switch and SF6 switchgear.
46	30	30-0000	Street Lighting	Index of Standard	REVISED	14	Updated titles of Std. 30-9780 and 30-9820, added 30-9860, removed 30-9500.
47	30	30-3700	Street Lighting	Underground 120 V Supply to Pole-Mounted Luminaire at the First Pole with In-Pole Circuit Breaker	REVISED	4	Revised BOM for ground wire and associated connector (from #6 to #2 AWG)
48	30	30-3800	Street Lighting	Underground 120 V Supply to Pole-Mounted Luminaire	REVISED	4	Revised BOM for ground wire and associated connector (from #6 to #2 AWG)
49	30	30-6400	Street Lighting	Pedestrian Lighting City Type II Post Top Mounted	REVISED	3	Added details 'C', 'D', and 'E'. Revised detail 'A', and 'B'. BOM change, title change, and additional revision of details.
50	30	30-9500	Street Lighting	Design Criteria Concrete Foundations for Base Mounted Street Light Poles	OBSOLETE	3	The information in this standard is existing in other standards. (duplicated information)
51	30	30-9510	Street Lighting	Civil Construction - Pole Base/Reinforced Sidewalk Bay General Information	REVISED	2	Added section regarding handwell locations within reinforced sidewalk bays
52	30	30-9780	Street Lighting	Reinforced Sidewalk Bay Concrete Pole - 25' Class B, Base Mounted	REVISED	5	Changed design of sidewalk bay with added notes and new BOM.
53	30	30-9820	Street Lighting	Pole Base / Reinforced Sidewalk Bay Aluminum Pole (Base Mounted)	REVISED	5	Revised design, notes, and BOM.
54	30	30-9860	Street Lighting	Pole base/Reinforced Sidewalk Bay, Pedestrian Scale-City Type 2, Victorian Poles.	NEW	0	New standard created to provide details on dimensions of pedestrian scale victorian poles.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #50

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
55	31	31-0000	Civil Construction	Index of Standard	REVISED	20	Addition of standard 31-5000 into index. Updated titles of Std. 31-1200, 31-1350, 31-8280.
56	31	31-1350	Civil Construction	Duct or Cable - Support in Place System	REVISED	2	Added new techniques of support-in-place construction. Removed certain dimensions.
57	31	31-8280	Civil Construction	Material Fabrication Cable Chamber Sump Grate 384 mm x 370 mm x 40 mm	REVISED	4	Added strut supports to diagram, changed dimensions of grate, added section B-B diagram.
58	34	34-0000	Engineering / References	Index of Standard	REVISED	5	Standard 34-2100 added to index.
59	34	34-3200	Engineering / References	Asset assembly - Additional Support Units	REVISED	1	Added a new row and column for contractor traffic control work.
60	34	34-3300	Engineering / References	Asset Assembly - Additional Resources	REVISED	3	Added a new row and column for third pole cut down work.
61	34	34-3400	Engineering / References	Asset assembly - Asset Removal Units Selection Table	REVISED	2	Added a new row and column for third pole cut down work.
62	34	34-4000	Engineering / References	Lock Reference	NEW	0	New standard to show various lock types and their applications.

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DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #51

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
1	04	04-1100	Poles and Pole Settings	General Information Wood (Cedar) Poles	REVISED	3	Corrected grammatical error.
2	04	04-2100	Poles and Pole Settings	Selection Criteria Wood (Cedar) Poles	REVISED	3	Updated the wood pole classification table. Moving the pole diameter table from 04-2100 to 04-5100 and adding note for reference.
3	04	04-2200	Poles and Pole Settings	Selection Criteria Concrete Poles	REVISED	2	Updated the concrete pole classification table. Updated pole class and guidline table and notes.
4	04	04-5300	Poles and Pole Settings	Cedar and Concrete Poles in Sidewalk	REVISED	3	Updated information for 65 and 70 foot poles. Updated BOM for 50, 55, and 60 foot concrete poles, 65 and 70 foot cedar poles.
5	05	05-1200	Pole Framing	4.16 to 27.6 Treeproof and Bare Primary 3-Phase Halo Configuration Angles 0 to 15 Degrees	REVISED	2	Added anti-split bolt installation to associated standards.
6	05	05-1260	Pole Framing	4.16 to 27.6 Treeproof and Bare Primary 3-Phase Inline Rolled Configuration Angles 0 to 15 Degrees	REVISED	3	Added anti-split bolt installation to associated standards.
7	05	05-2460	Pole Framing	4.16 to 27.6 Treeproof and Bare Primary 3-Phase Mid-Span Tap Horizontal Configuration	REVISED	2	Changed tap material from stockcode 7105230 to 9662862.
8	05	05-2480	Pole Framing	4.16 to 27.6 Treeproof and Bare Primary 3-Phase Mid-Span Tap Vertical Configuration	REVISED	1	Changed tap material from stockcode 7105230 to 9662862.
9	05	05-6070	Pole Framing	System Neutral Tap And Run-off	REVISED	2	Changed tap material from stockcode 7105230 to 9662862.
10	07	07-3600	Anchoring and Guying	Guying Location of Guy Insulator	REVISED	3	Note and drawing have been revised for second guy insulator installation details.
11	07	07-4000	Anchoring and Guying	Guying Components	REVISED	4	Revised the name and description of thimble clevis.
12	07	07-4230	Anchoring and Guying	Guying Installation Procedure Guy Strand Termination at Eye Nut	REVISED	4	Revised the drawing and note of thimble clevis.
13	07	07-4300	Anchoring and Guying	Guying Installation Details Guy Attachments to Concrete Pole	REVISED	2	Revised the drawing and description of thimble clevis.
14	07	07-4310	Anchoring and Guying	Guying Installation Details Guy Attachments to Wood Pole	REVISED	2	Revised the drawing and description of thimble clevis.
15	07	07-5170	Anchoring and Guying	V-Guying on Concrete, Wood or Steel Pole Using insulator rods on armless construction	REVISED	2	Green Guy Guard obsolete. BOM & BOM Legend have been revised.
16	07	07-5300	Anchoring and Guying	Span & Down Guy - One on Concrete, Wood or Steel Pole	REVISED	7	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
17	07	07-5310	Anchoring and Guying	Span & Down Guy - One on Concrete, Wood or Steel Pole Using Insulator Rod	REVISED	7	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
18	07	07-5320	Anchoring and Guying	Span & Down Guy -Two on Concrete, Wood or Steel Pole	REVISED	8	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
19	07	07-5340	Anchoring and Guying	Span & Strut Guy - One on Concrete, Wood or Steel Pole	REVISED	8	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
20	07	07-5350	Anchoring and Guying	Span & Strut Guy - One on Concrete, Wood or Steel Pole Using Insulator Rod	REVISED	8	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
21	07	07-5370	Anchoring and Guying	Span & Strut Guy - Two on Concrete, Wood or Steel Pole With One Span Guy Using Insulator Rod	REVISED	9	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #51

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
22	07	07-5380	Anchoring and Guying	Span & Strut Guy - Two on Concrete, Wood or Steel Pole Using Insulator Rod	REVISED	6	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
23	07	07-5400	Anchoring and Guying	Storm Guy on Concrete or Wood Pole	REVISED	6	Removed stockcode 2450035 and 2450026 from BOM.
24	07	07-5500	Anchoring and Guying	Span Guy - One on Concrete, Wood or Steel Pole	REVISED	6	Note has been revised for second guy insulator installation details. Revised the drawing and description of thimble clevis.
25	09	09-0000	Overhead Transformers	Index of Standards	REVISED	14	Removed obsolete standard 09-8400, 09-8600, and 09-8800 from index.
26	09	09-1300	Overhead Transformers	General Information Installation	REVISED	6	Table description change.
27	09	09-1400	Overhead Transformers	General Information Bushing Configurations	REVISED	4	Pole mounted transformer stock code change.
28	09	09-8100	Overhead Transformers	1 Phase Construction 2400-120/2401 V All kVA Sizes	REVISED	7	Added secondary risers bundled together and pole-mounted transformer stock code change.
29	09	09-8200	Overhead Transformers	1 Phase Construction 8000-120/240 V All kVA Sizes	REVISED	8	Added secondary risers bundled together and pole-mounted transformer stock code change.
30	09	09-8300	Overhead Transformers	1 Phase Construction 16000-120/240 V A kVA Sizes	REVISED	9	Added secondary risers bundled together and pole-mounted transformer stock code change.
31	09	09-8400	Overhead Transformers	3-Phase Construction 2400/4160-120/208V - 50 kVA	OBSOLETE	11	Obsoleted 09-8400 and moved to 09-8500
32	09	09-8500	Overhead Transformers	3-Phase Construction 2400/4160 -120/208V - All kVA Sizes	REVISED	11	Added standard 09-8600 with 50 kVA to 09-8700. Updated the transformer kit and transformers' stock codes in BOM.
33	09	09-8600	Overhead Transformers	3-Phase Construction 8000/13800-120/208V - 50 kVA	OBSOLETE	11	Obsoleted 09-8600 and moved to 09-8700
34	09	09-8700	Overhead Transformers	3-Phase Construction 8000/13800-120/208V - All kVA Sizes	REVISED	13	Added standard 09-8600 with 50 kVA to 09-8700. Updated the transformer kit and transformers' stock codes in BOM.
35	09	09-8800	Overhead Transformers	3-Phase Construction 16000/27600-120/2080V - 50 kVA	OBSOLETE	15	Obsoleted 09-8800, moved to 09-8900.
36	09	09-8900	Overhead Transformers	3-Phase Construction 16000/27600-120/2080V All kVA Sizes	REVISED	14	Added standard 09-8600 with 50 kVA to 09-8700. Updated the transformer kit and transformers' stock codes in BOM.
37	09	09-9100	Overhead Transformers	3-Phase Construction 2400/4160-347/600V WYE 100 & 167 kVA	REVISED	15	Updated the transformer kit and transformers' stock codes in BOM.
38	09	09-9200	Overhead Transformers	3-Phase Construction 8000/13800-347/600V WYE All kVA Sizes	REVISED	15	Updated the transformer kit and transformers' stock codes in BOM.
39	09	09-9300	Overhead Transformers	3-Phase Construction 16000/27600-347/600V WYE All kVA Sizes	REVISED	17	Pole mounted transformer stock code change.
40	09	09-9500	Overhead Transformers	Primary Drop Leads 1-Phase Transformers	REVISED	6	Added additional support arm, revised dimensions, removed AMPACTS from open bin.
41	09	09-9510	Overhead Transformers	Primary Drop Leads 1-Phase Transformers - Dead-End Configuration	REVISED	3	Added additional support arm.
42	09	09-9600	Overhead Transformers	Primary Drop Leads 3-Phase Transformers - Overbuild Only	REVISED	6	Added additional support arm, removed AMPACTS from open bin.
43	09	09-9610	Overhead Transformers	Primary Drop Leads 3-Phase Transformers - Dead-End Configuration	REVISED	2	Added additional support arm.
44	11	11-2020	O/H Secondary & Primary Services	Overhead Secondary Bus, Transformer Secondary Drop Leads And Secondary Services	REVISED	5	Revised note a) to "All secondary busses shall be installed on the street side of the pole; except when the line angle is greater than 3 degrees, then the bus may be installed on the house side of the pole."
45	11	11-3550	O/H Secondary & Primary Services	Multiplexed Secondary Bus Service Taps 600V or 347/600 V at Mid-span	REVISED	3	Corrected the BOM legend description of "at pole" to " at mid-span".

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #51

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
46	12	12-3000	Primary and Secondary Service Risers	Primary Services Risers Primary Drops And Connections For 1-Phase Service Riser	REVISED	6	Showing the stand off installation dimensions and updating the 3D view.
47	12	12-3100	Primary and Secondary Service Risers	Primary Services Risers Primary Drops And Connections For 3-Phase Service Riser	REVISED	6	Showing the stand off installation dimensions and updating the 3D view.
48	12	12-4000	Primary and Secondary Service Risers	Primary Feeder Riser, 3-phase 27.6 kV 600A	REVISED	12	Consolidated open bin list with standard list. Changed 350 kcmil wire from 427 str to 61 str CU Wire and associated terminal lug. Added grounding stirrup for duck bill clamp, and longer ½" bolt for use with Std. 10-3000 (added BOM Legend C and D). Added hardware for grounding of bracket and removed reference to equipment grounding standard. Updated required quantity of ½" bolts and associated hardware. Added Detail 'A' and Detail 'B' for terminal lug. Updated required quantity of white wedge connectors. Revised note 12 from "temporary attachment of primary cables" to "cable guard or pipe installation details". Removed item 2420260 bracket termination support since it is provided with termination kit (reference standard 16-4160).
49	12	12-4500	Primary and Secondary Service Risers	Primary Feeder Riser, 3-phase 13.8 kV 600A	REVISED	9	Consolidated open bin list with standard list. Changed 350 kcmil cable from 427 str to 61 str CU Wire and associated terminal lug. Added grounding stirrup for duck bill clamp. and longer ½" bolt for use with Std. 10-3000 (added BOM Legend I and J). Added hardware for grounding of equipment arm and removed reference to equipment grounding standard. Updated required quantity of ½" bolts and associated hardware. Revised bolt from 3" bolt to 3-1/2" bolt. Added notes 4 and 5. Removed PILC pothead terminations from BOM Legend (A, B, E, F) and Detail B and Detail C. Added Detail B and C for terminal lug. Updated required quantity of RWB disks. Included required quantity of banding. Included grounding wire along bracket.
50	13	13-2020	UG Transformer and Switchgears	4.16kV Transformer Vaults/rooms ARC Stranglers with three 50, 100 & 167 kVA Transformers - Single feeder supply	REVISED	4	Added fault indicators for each primary feeder.
51	13	13-2030	UG Transformer and Switchgears	4.16kV Transformer Vaults/rooms ARC Stranglers with three 50, 100 & 167 kVA Transformers - Dual feeder supply	REVISED	4	Added fault indicators for each primary feeder.
52	13	13-2040	UG Transformer and Switchgears	4.16 kV Transformer Vaults ARC Stranglers with three 50, 100 & 167 kVA Transformers Non-Standard vaults single feeder supply	REVISED	4	Added fault indicators for each primary feeder.
53	13	13-4020	UG Transformer and Switchgears	13.8 kV Compact Radial Design - General Information	REVISED	8	Added fusing cabinet related information.
54	13	13-5100	UG Transformer and Switchgears	13.8 kV Network System Network protector automation	REVISED	2	Revised communication box installation clearance and BOM quantity.
55	13	13-7030	UG Transformer and Switchgears	Customer Transformer Vault for 1 PH Transformer 13.8 kV & 27.6 kV Distribution System	REVISED	6	Added fault indicators for each primary feeder.
56	13	13-7050	UG Transformer and Switchgears	3 1-Phase Transformer Vault 13.8 kV Typical Layout	REVISED	5	Added fault indicators for each primary feeder. Revised the drawing by adding showing the elbows.
57	13	13-7060	UG Transformer and Switchgears	3 1-Phase Transformer Vault 27.6 kV Typical Layout	REVISED	6	Added fault indicators for each primary feeder. Revised the drawing by adding showing the elbows.
58	16	16-0000	UG Cables Joints Terminations & Connectors	Index of Standards	REVISED	14	Added new standard 16-4630 to index.
59	16	16-4260	UG Cable, Joints, Terminations & Connections	Primary Trxple Terminations 600 A Deadbreak Connectors 28 kV, 1 Conductor	REVISED	4	Revised the drawing for grounding of LACT shield. Updated the wire to #2 19 STR copper wire.
60	16	16-4370	UG Cable, Joints, Terminations & Connections	Grounding Clamp Assembly Shielded Cable	REVISED	2	Added item 9665444 to cable size table. Revised the descriptions of other items in cable size table. Modified the drawing of PVC tape in the sketch.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #51

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
61	16	16-4420	UG Cable, Joints, Terminations & Connections	Primary - TRXLPE Application Bonding For Hand Taped Straight Splices	REVISED	2	Added 7 items in BOM Legend and revised BOM as well. Revised notes on page 2 and 3.
62	16	16-4540	UG Cable, Joints, Terminations & Connections	Primary Cable Support of Splices on Cable Arms	REVISED	3	Deleted item 9662901 , added item 5240030 and 7360306 to BOM. Created the detail of polymeric or transition splice in the sketch.
63	16	16-4580	UG Cable, Joints, Terminations & Connections	Primary - Inline Transition Joint Hand Taping Method 15 kV, Cu, 1 conductor PILC to TRXLPE	REVISED	4	Added 1C 1000 kcmil Cu shielded PILC to 1C 750 KCMIL Cu TRXLPE and 1C 1000 kcmil Cu shielded PILC to 1C 1000 KCMIL Cu TRXLPE to BOM legend. Revised the note on page 2 and 3.
64	16	16-4600	UG Cable, Joints, Terminations & Connections	Primary - Inline Transition Joint Hand Taping Method 28 kV, Cu, 1 conductor PILC to TRXLPE	REVISED	2	Added 1C 1000 kcmil Cu shielded PILC to 1C 750 KCMIL Cu TRXLPE and 1C 1000 kcmil Cu shielded PILC to 1C 1000 KCMIL Cu TRXLPE to BOM legend. Revised the note on page 2 and 3.
65	16	16-4630	UG Cable, Joints, Terminations & Connections	Primary - Transition Joint Bonding For Hand Taped Inline Transition Splices	NEW	0	New standard created for additional guidance to crews on installing primary transition joint.
66	18	18-5100	Grounding	Underground System Cable Chamber Grounding	REVISED	4	Revised method of supporting neutral cables from wall clips to cable clamps on unistrut, Removed cable joint from standard, and associated note reference and #1/0 wire from BOM, Included dimensions of previous note 1 on the drawing. Revised quantity of hardware for cable chamber size of 3.5 m x 4 m.
67	23	23-1400	Foreign Attachments	Overhead System - Pole Attachments Enbridge Gas Rectifier	REVISED	1	Added 50 V 12A rectifier to standard.
68	27	27-3000	Legend/Drafting Symbols	Conductors and Connectors	REVISED	4	Change Transition Splice to "Transition Splice PILC to TRXLPE".
69	27	27-8000	Legend/Drafting Symbols	Assemblies	REVISED	5	Removed 13.8 kva from description.
70	28	28-0000	OH and UG Material Fabrications	Index of Standards	REVISED	5	Added new standards 28-0421, 28-0422 to index.
71	28	28-0421	OH and UG Material Fabrications	Concrete Pole 9.41 m (30'-0") Class C Base Mount	NEW	0	New standard for concrete pole.
72	28	28-0422	OH and UG Material Fabrications	Concrete Pole 10.67 m (35'-0") Class C Base Mount	NEW	0	New standard for concrete pole.
73	31	31-0000	Civil Construction	Index of Standards	REVISED	21	Added new standard 31-0800 to index.
74	31	31-0800	Civil Construction	Mapping of Underground Utility Infrastructure	NEW	0	New standard for Mapping of all TH underground assets.
75	31	31-1150	Civil Construction	Conduits - Reduced Depth of Cover	REVISED	5	Material change to replace steel plates.
76	31	31-1220	Civil Construction	Conduits - Installation of Bends of Poles	REVISED	11	Removed product as it was financially unfeasible .
78	31	31-5000	Civil Construction	Padmounts Precast Concrete Lid (Cover) To Convert Padmount To a Splice Box	REVISED	1	Corrected the dimensions of 3 phase precast concrete lid to 1830mm.
79	31	31-5120	Civil Construction	Splice Vault 'A' for 1000	REVISED	6	Relocated duct entry points for ease of installation and cable organization.
80	31	31-8340	Civil Construction	Aluminum Ladderway Grating Guard	REVISED	5	Guard has been revised to be more durable.
81	34	34-3300	Engineering / References	Asset assembly - Additional Resources	REVISED	3	Added a new column for Daily Travel benchmark.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #52

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
1	03	03-2000	Clearances	Overhead - Minimum Vertical Separations - Standard Attachment Points	REVISED	9	Note 2 revised to combine 2D and 2E which refer to section 10. Note 7 revised to clarify that minimum seperation between SL brackets and communication attachment is 1m. Note 9 added to specify minimum seperation between secondary busses.
2	04	04-0000	Poles and Pole Settings	Index of Standards	REVISED	5	Standard 04-5400 added to index.
3	04	04-5300	Poles and Pole Settings	Cedar and Concrete Poles - In Sidewalk	REVISED	4	Added 35' and 75' pole to standard.
4	04	04-5400	Poles and Pole Settings	Cedar and Concrete Poles - In Boulevard and Sidewalk, for TTC Trolley Suspension	REVISED	3	Added 35' pole to standard.
5	04	04-5700	Poles and Pole Settings	Steel Pole - In Blvd, for TTC Trolley Suspension (Hand Dig and Vacuum Truck)	REVISED	2	Corrected Typo (m to mm).
6	04	04-5800	Poles and Pole Settings	Steel Poles - In Sidewalk, for TTC Trolley Suspension (Hand Dig and Vacuum Truck)	REVISED	2	Corrected Typo (m to mm).
7	08	08-3130	Overhead Conductors And Connectors	Overhead Connectors - Full Tension and Non-Tension Sleeves Application	REVISED	2	Standard 08-3130 was revised to provide appropriate language as to how many sleeves can be installed as well as developed.
8	10	10-3710	Overhead Switches	SCADA Antenna Mounting Detail - 13.8kV & 27.6kV Systems	REVISED	4	Revised BOM item #3 from 3/4" to 3/8" strap. Added quantities for previously listed open bin items. Removed note 4 that referenced standard practices SP#005. Revised 1m seperation to 1.5m to account for omni-directional antenna length.
9	11	11-2020	Overhead Primary and Secondary Service	Overhead Secondary - Secondary Bus, Transformer Secondary Drop Leads and Secondary Services	REVISED	6	Revised minimum vertical seperation from 10" to 20" between adjacent busses.
10	15	15-1400	UG Secondary and Primary Services	General Information Typical Underground Entrance for Services 1200 A and Up - Collector or Stub Buses	REVISED	4	Added new note (7) and renumbered notes to accommodate change.
11	15	15-5100	UG Secondary and Primary Services	Secondary Underground Services 600 A - 2000 A Fed from Transformer Vault/Pad-Mounted Transformer	REVISED	5	Added new note (3) to provide information for Pad Mounted Transformers on Customer Property.
12	16	16-3700	UG Cables, Joints, Terminations & Connectors	Primary - TRXLPE Straight Joint - Hand Taped Splice, 15kV, 1 Conductor	REVISED	5	Additional comments added to stipulate when this standard should be used. Open Bin Material Section in BOM was removed.
13	16	16-4580	UG Cables, Joints, Terminations & Connectors	Primary - Inline Transition Joint - Hand Taping Method 15kV, Cu, 1 Conductor PILC to TRXLPE	REVISED	5	Additional comments added to stipulate when this standard should be used. Open Bin Material Section in BOM was removed.
14	16	16-4600	UG Cables, Joints, Terminations & Connectors	Primary - Inline Transition Joint - Hand Taping Method 28kV, Cu, 1 Conductor PILC to TRXLPE	REVISED	3	Additional comments added to stipulate when this standard should be used. Open Bin Material Section in BOM was removed.
15	16	16-6200	UG Cables, Joints, Terminations & Connectors	Cable Reel Data - Approved Standard Reel Sizes	REVISED	4	Updated note 2 to follow the latest edition of NEMA Standards.
16	16	16-6210	UG Cables, Joints, Terminations & Connectors	Cable Reel Data - Cable and Wire Reel Chart	REVISED	10	Added 5 new types of cable (9665326, 9665327, 9665328, 9665329, 9665330) to the chart. Revised some cable data.
17	18	18-2300	Grounding	Overhead System - Wood Pole - Ground Wire Installation Details	REVISED	7	Revised BOM legend to include option B for bom without ground rod, included quantity for staples since open bin has been removed
18	30	30-0000	Street Lighting	Index of Standards	REVISED	15	Standard 30-1350 added to index.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #52

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
19	30	30-1350	Street Lighting	Underground Unshielded Cable Testing (#2 and #6 Cables Rated 600V or Less)	NEW	0	New standard created for cable testing.
20	31	31-0000	Civil Construction	Index of Standards	REVISED	22	Name for standard 31-7100 in index was edited to match the title of the standard.
21	31	31-0100	Civil Construction	Underground Clearances	REVISED	7	Revised clearances to meet existing MCR.
22	31	31-1310	Civil Construction	Underground Conduits - Crossing Railway Tracks	REVISED	3	Adjusted requirements to accommodate GO Metrolinx RER tracks.
23	31	31-6020	Civil Construction	Customer-Owned Structures - Above Grade - Walk-In Vault	REVISED	8	Standard revised to provide better readability. Note 4 was removed and a new Note 5 was added - the numbering of notes was changed to accommodate this revision.
24	31	31-7100	Civil Construction	Draining Structures	REVISED	4	Dimensions of reducer fitting adjusted to 150 mm for both the reducer and NPS.
25	51	51-0000	Cable Tray Supports	Index of Standards	REVISED	3	Standards 51-4500, 51-4510 and 51-4520 added to index.
26	51	51-4500	Cable Tray Supports	EMT Conduit Run	NEW	0	New Standard created for EMT Conduit Run.
27	51	51-4510	Cable Tray Supports	EMT Conduit Support Distances	NEW	0	New Standard created for EMT Conduit Support Distances.
28	51	51-4520	Cable Tray Supports	Conduit Fill	NEW	0	New Standard created for Maximum Conduit Fill.
29	57	57-2100	Station Equipment	DC System 125 V 200 AH - 400 AH with Free Standing Charger	REVISED	1	BOM Revised due to Obsolete Stock Code.
30	57	57-2120	Station Equipment	DC System 125 V 50 AH - 100 AH with Free Standing Charger	REVISED	1	BOM Revised due to Obsolete Stock Code.
31	57	57-2130	Station Equipment	DC System 125 V 50 AH - 100 AH with Wall Mounted Charger	REVISED	1	BOM Revised due to Obsolete Stock Code.
32	57	57-2140	Station Equipment	DC System 48 V 50 AH - 100 AH with Free Standing Charger	REVISED	1	BOM Revised due to Obsolete Stock Code.
33	59	59-0000	Stations Legend/Drafting	Index of Standards	NEW	0	Index created for new Standards' Section - Stations Legend/Drafting.
34	59	59-1000	Stations Legend/Drafting	General Information	REVISED	1	New Standard created for General Information, revision was made due to feed back from the stations department.
35	59	59-1010	Stations Legend/Drafting	Circuit Breakers	NEW	0	New Standard created for Circuit Breakers Symbol Library.
36	59	59-1020	Stations Legend/Drafting	Transformers	NEW	0	New Standard created for Transformers Symbol Library.
37	59	59-1030	Stations Legend/Drafting	Relays	REVISED	1	New Standard created for Relays Symbol Library.
38	59	59-1040	Stations Legend/Drafting	Switches	NEW	0	New Standard created for Switches Symbol Library.
39	59	59-1050	Stations Legend/Drafting	Ground and Lightning	NEW	0	New Standard created for Ground and Lightning Symbol Library.
40	59	59-1060	Stations Legend/Drafting	Instrumentation and Metering	NEW	0	New Standard created for Instrumentation and Metering Symbol Library.
41	59	59-1070	Stations Legend/Drafting	Cables	NEW	0	New Standard created for Cables Symbol Library.
42	59	59-1080	Stations Legend/Drafting	Fusing	New	0	New Standard created for Fusing Symbol Library
43	59	59-1090	Stations Legend/Drafting	Miscellaneous	New	0	New Standard created for Miscellaneous Symbol Library

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #52

#	STANDARDS SECTION #	STANDARD #	SECTION TITLE	STANDARD NAME	STATUS New/Revised /Obsolete	Revision number at date of issue	REVISION DESCRIPTION
44	70	70-11	Reactive Maintenance Standards	Legacy Overhead Secondary Services - Compression Sleeves Selection Table	NEW	0	Standard 70-11 provides a guide between the old and new cables, and the type of sleeves they need to complete the project.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #53

#	Standards Section #	Standard #	Section Title	Standard Name	STATUS New/Revised/ Obsolete	REVISION NUMBER at date of issue	Revision Description
1	03	03-0000	Clearances	Index of Standards	REVISED	6	Standards 03-2160 and 03-2170 added to index.
2	03	03-1100	Clearances	Overhead - General Information	REVISED	5	Revised minimum horizontal and vertical clearances.
3	03	03-2160	Clearances	Overhead - Minimum Vertical Clearances - Toronto Hydro Lines Perpendicular to Metrolinx Electrified Rail	NEW	0	New Standard to address clearances when Toronto Hydro (TH) overhead lines are perpendicular to the Metrolinx (MX) electrified rail.
4	03	03-2170	Clearances	Overhead - Minimum Vertical Clearances - Toronto Hydro Lines Parallel to Metrolinx Electrified Rail	NEW	0	New Standard to address clearances when Toronto Hydro (TH) overhead lines are parallel to the Metrolinx (MX) electrified rail.
5	04	04-1100	Poles and Pole Settings	General Information - Wood (Cedar) Poles	REVISED	4	Revision to Storage Section to include Conversion Table.
6	04	04-7300	Poles and Pole Settings	Reinforce Sidewalk Bays Cedar Poles - 38.5' and 43' Class 3, Base Mounted	REVISED	4	Note 4 revised to remove the mention of pole surface treatment. Note 6 added to reference AODA requirements.
7	05	05-1280	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary - 3-Phase Tangent Horizontal Configuration 0 to 3 Degrees	REVISED	3	Standard revised to include overbuild horizontal framing configuration.
8	05	05-1590	Pole Framing	4.16 to 27.6 kV Treeproof and Bare Primary - 3-Phase Double Dead-End Horizontal Configuration	REVISED	2	Note 7 added to mention that the Red, White, and Blue phases on either side of the horizontal dead-end shall be the same.
9	07	07-1300	Anchoring and Guying	Anchoring - Positioning of Anchors	REVISED	2	Revised to include new section for Anchor Alignment with Pole.
10	08	08-3120	Overhead Conductors and Connectors	Overhead Connectors - Hand Taping of Sleeve for Primary Tree Proof Cable For Retrofit Application	REVISED	1	Revised to include reinsualtion of tree proof cables where the covering has been cut back to accommodate installation of temporary grounds.
11	08	08-3160	Overhead Conductors and Connectors	Overhead Connectors - Non-Tension Compression Sleeves Selection Table	REVISED	2	Revised to add stock code for non-tension Al 250 kcmil sleeve.
12	09	09-3800	Overhead Transformers	Installation 1 -Phase Transformer Monitor	REVISED	1	Revised note 5 to explicitly state the ordering of two replacements kits.
13	10	10-0000	Overhead Switches	Index of Standards	REVISED	10	Standard 10-1310 added to index. Standards 10-1100, 10-1120 and 10-3100 removed from index. Title change for Standard 10-1300.
14	10	10-1100	Overhead Switches	Disconnect In-Line Switches - Solid Blade 600 A double dead-end 4.16 kV to 27.6 kV Horizontal Configuration	OBSOLETE	7	Standard 10-1100 has been incorporated into Standard 10-1300.
15	10	10-1120	Overhead Switches	Disconnect In-Line Switches - Fused 200 A Double Dead-End 13.8 kV to 27.6 kV Horizontal Configuration	OBSOLETE	1	Standard 10-1120 has been incorporated into new Standard 10-1310.
16	10	10-1300	Overhead Switches	Disconnect In-Line Solid Blade Switches - All Voltages and Configurations	REVISED	9	Fused switch (permutation B) has been moved to new Standard 10-1310. Overbuild horizontal framing configuration added.
17	10	10-1310	Overhead Switches	Disconnect In-Line Switches Fused 200A 13.8 kV to 27.6 kV	NEW	0	New Standard created for in-line fused switches, including new AMPACT Fuse In-Line Mount Switch.
18	10	10-3100	Overhead Switches	3-Phase Load Interrupter Switch SCADA-Operated 13.8 & 27.6 kV Feeder Riser	OBSOLETE	2	Standard has been moved to Section 70 for reactive maintenance use only.
19	11	11-0000	Overhead Primary and Secondary Service	Index of Standards	REVISED	10	Standard 11-3220 added to index.Title Change for Standards 11-2050 and 11-3810.
20	11	11-2050	Overhead Primary and Secondary Service	Overhead Secondary Services Temporary Service Connection - Up to 200 Amp Service	REVISED	1	Standard revised to clarify the scope of temporary service connection for up to 200 A service (120/240V, 120/208V or 347/600V). Revision includes changes to Figure, Notes, Dimensions, and Title.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #53

#	Standards Section #	Standard #	Section Title	Standard Name	STATUS New/Revised/ Obsolete	REVISION NUMBER at date of issue	Revision Description
21	11	11-3220	Overhead Primary and Secondary Service	Multiplexed or Field Lashed Secondary Bus - Angles 46 to 90 Degrees on Concrete or Wood Pole	NEW	0	SKE-331 converted to a Standard.
22	11	11-3810	Overhead Primary and Secondary Service	Multiplexed Secondary Bus - Temporary Service Tap at Transformer Pole for Construction Site 347/600 V, 400 A and 600 A, 3-Phase	REVISED	1	Standard revised to clarify that it is applicable for 400 A and 600 A service. Revision includes changes to Notes and Title.
23	13	13-0000	UG Transformers and Switchgears	Index of Standards	REVISED	13	Standard 13-7550 added to index. Title change for Standard 13-2100.
24	13	13-2010	UG Transformers and Switchgears	4.16 kV Transformer Vault Layout & Installation of Three 50, 100 & 167 kVA Transformers	REVISED	4	Revised to accommodate vibration pad installation in vault type transformer vault.
25	13	13-2100	UG Transformers and Switchgears	Transformer Vault Drainage With or Without Sump Pump	REVISED	2	Title Change. Standard updated to include new sump pump and drainage requirements.
26	13	13-2200	UG Transformers and Switchgears	Vault Lighting Arrangement	REVISED	2	Revised to include vault lighting selection for one network vault.
27	13	13-5010	UG Transformers and Switchgears	13.8 kV Network System - Network Transformer Vaults	REVISED	9	Revised to reference underground service cable limiters from associated standard.
28	13	13-5020	UG Transformers and Switchgears	13.8 kV Network System - Typical Stand Alone Network Protector (SANP) Vault	REVISED	3	Revised to reference underground service cable limiters from associated standard.
29	13	13-5100	UG Transformers and Switchgears	13.8 kV Network System - Network Protector Automation	REVISED	3	Revision to diagram. Moved location of fibr patch panel and vault communication box for better access.
30	13	13-7010	UG Transformers and Switchgears	27.6 kV or 13.8 kV 1-Ph Submersible Transformer Vault	REVISED	13	Revision depicts layout with new disconnectable connector and provides new BOM option for 8-14 secondary terminations.
31	13	13-7030	UG Transformers and Switchgears	Customer Transformer Vault For 1-Ph Transformer -13.8 kV & 27.6 kV Distribution System	REVISED	7	Revised standard and BOM to accommodate vibration pad installation in vault type transformer.
32	13	13-7050	UG Transformers and Switchgears	3 1-Phase Transformer Vault 13.8 kV Typical Layout	REVISED	6	Revised Standard and BOM to accommodate vibration pad installation in vault type transformer.
33	13	13-7060	UG Transformers and Switchgears	3 1-Phase Transformer Vault 27.6 kV Typical Layout	REVISED	7	Revised Standard and BOM to accommodate vibration pad installation in vault type transformer.
34	13	13-7080	UG Transformers and Switchgears	Delta Vault - Typical Electrical Layout - 27.6 kV Loop System	REVISED	7	Revised Standard and BOM to accommodate vibration pad installation in vault type transformer.
35	13	13-7200	UG Transformers and Switchgears	Grd. Y Vault-Typical Electrical Layout - 27.6 kV System	REVISED	11	Revised Standard and BOM to accommodate vibration pad installation in vault type transformer.
36	13	13-7500	UG Transformers and Switchgears	3 1-Phase Transformer Vault 27.6 kV Customer Room with SF6 Switchgear	REVISED	3	Revised Standard and BOM to accommodate vibration pad installation in vault type transformer.
37	13	13-7520	UG Transformers and Switchgears	3 1-Phase Transformer Vault - 13.8 kV Customer Room with SF6 Switchgear	REVISED	1	Revised Standard and BOM to accommodate vibration pad installation in vault type transformer.
38	13	13-7550	UG Transformers and Switchgears	Vibration Pads for Distribution Transformers	NEW	0	New Standard developed for vibration pad installation.
39	14	14-1070	Padmounted Transformers	27.6 Grd. 16 kV 3-Phase - Radial/Loop System	REVISED	4	Revised to include minimum impedance percentage for 750-1000 kVA and 1500 kVA units.
40	15	15-0000	UG Secondary and Primary Services	Index of Standards	REVISED	9	Title change for Standard 15-3800.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #53

#	Standards Section #	Standard #	Section Title	Standard Name	STATUS New/Revised/ Obsolete	REVISION NUMBER at date of issue	Revision Description
41	15	15-3800	UG Secondary and Primary Services	Underground Secondary Services Temporary Service Connection - Up to 200A Service	REVISED	2	Standard revised to clarify the scope of temporary service connection for up to 200 A service (120/240V, 120/208V or 347/600V). Revision includes changes to Figure, Notes, Dimensions and Title.
42	16	16-0000	UG Cables, Joints, Terminations & Connectors	Index of Standards	REVISED	15	Standards 16-1300 and 16-6010 added to index. Title change for Standard 16-6000.
43	16	16-0940	UG Cables, Joints, Terminations & Connectors	Cable Ratings - 4.16 kV RILC	REVISED	2	BOM revised to update obsolete stock code.
44	16	16-1300	UG Cables, Joints, Terminations & Connectors	Fault Locating Strategy - Underground Primary Cable	NEW	0	New Standard created for Fault Locating Strategy for Underground Primary Cable.
45	16	16-6000	UG Cables, Joints, Terminations & Connectors	Secondary Terminations - Submersible Transformer Terminal Cluster for Non-Removable Low Voltage Terminal/Spade 600 V or Below	REVISED	7	Title revised and note 2 added to notify users that this standard is applicable for legacy transformers with Non-Removable Terminal/Spade.
46	16	16-6010	UG Cables, Joints, Terminations & Connectors	Secondary Terminations - Submersible Transformer Terminal Cluster for Removable Low Voltage Terminal/Spade 600 V or Below	NEW	0	New Standard created to show the components required for installing disconnectable flood seal connectors.
47	18	18-4100	Grounding	Overhead System Communication Messenger Bonding	REVISED	5	Copper wire size changed from #2 to #6 AWG to align with communication company standards.
48	21	21-1000	Overhead and Underground Stenciling	General Information - Location and Equipment Numbering	REVISED	5	Revision to note 3 to include reference to Standard 53-5000.
49	21	21-1100	Overhead and Underground Stenciling	General Information - Stenciling Materials	REVISED	7	Outdoor and Indoor Danger Signs added to BOM.
50	23	23-1220	Foreign Attachments	Overhead System - Pole Attachments - Communication Riser and Neutral Bonding	REVISED	3	Copper wire size changed from #2 to #6 AWG to align with communication company standards.
51	24	24-0000	Fusing	Index of Standards	REVISED	4	Standard 24-2200 added to index.
52	24	24-2200	Fusing	Underground Fusing - Pad-Mount Bay-O-Net Fuses	NEW	0	New Standard created to show the stock codes for field replaceable Bay-O-Net fuses for 1-Phase and 3-Phase Pad-Mount Transformers.
53	27	27-4100	Legend/Drafting Symbols	Civil Structures	REVISED	4	Revised primary splice box and secondary splice tap box.
54	30	30-0000	Street Lighting	Index of Standards	REVISED	16	Title change for Standard 30-4280.
55	30	30-4220	Street Lighting	Concrete Pole with Cobra Head Luminaire	REVISED	9	BOM revised to include 30' and 35' Base Mounted Pole.
56	30	30-4280	Street Lighting	Aluminum Pole - Davit Style for Expressways/Highways with Cobra Head Luminaire	REVISED	2	Title revised. Additional revisions made to provide details on dimensions and installation methods.
57	31	31-0000	Civil Construction	Index of Standards	REVISED	23	Standard 31-2250 added to index.
58	31	31-1100	Civil Construction	Conduits - General Information	REVISED	6	Standard revised to include electrical and communication cables.
59	31	31-1120	Civil Construction	Conduits - Concrete Encased and Direct Buried Ducts	REVISED	8	Revised to account for the use of RED ducts for all new or rebuild direct buried THESL communication cables.
60	31	31-1400	Civil Construction	Duct Sealant Installation	REVISED	1	Revised to fix typo. Nofrino should be Nofirno.
61	31	31-2250	Civil Construction	Cable Chambers - Core Drilling into Existing Cable Chamber	NEW	0	New standard created to provide guidelines on core drilling in exisiting cable chambers.
62	34	34-1000	Engineering/References	Construction Deviation Guidelines	REVISED	4	Revision made to Deviations section to distinguish design/engineering responsibility for review/sign-off.
63	53	53-0000	Stenciling	Index of Standards	REVISED	4	Standard 53-5000 added to index.
64	53	53-5000	Stenciling	Customer Indoor or Outdoor Substation Stenciling for 13.8 kV Switchgear Underground Radial in Former Toronto District	NEW	0	No previous Standard for 13.8 kV Switchgear.

DISTRIBUTION CONSTRUCTION STANDARDS
REVISION #53

#	Standards Section #	Standard #	Section Title	Standard Name	STATUS New/Revised/ Obsolete	REVISION NUMBER at date of issue	Revision Description
65	55	55-0000	Cable Terminations	Index of Standards	REVISED	2	Title change for Standard 55-3110.
66	55	55-3110	Cable Terminations	Station Transformer Termination - 13.8 kV and 4.16 kV Station Transformer Secondary Termination	REVISED	1	Revision to title and notes. Addition of a Recommended Cables for Transformer Ratings Chart.
67	59	59-0000	Stations Legend/Drafting	Index of Standards	REVISED	1	Standard 59-2000 added to index.
68	59	59-2000	Stations Legend/Drafting	Conductor Naming Convention	NEW	0	New Standard created for conductor naming convention.

Toronto Hydro Asset Condition Assessment Methodology

Table of Contents

1. Introduction

This report discusses Toronto Hydro's approach to Asset Condition Assessment ("ACA"). Sections 2a and 2b provide a brief description of ACA and how it is used in asset management. Sections 2c and 2d discuss the legacy approach (weighted arithmetic summation model) used by Toronto Hydro and the associated limitations which led to the decision in 2016 to adopt a new methodology. Toronto Hydro's selection of the Common Network Assets Indices Methodology ("CNAIM"), which was developed and used by utilities in the U.K., is discussed in Section 3 and its implementation in Section 4. The Appendices provide additional details on the ACA algorithm and parameters as well as ACA results for Toronto Hydro assets assessed using the methodology.

2. Asset Condition Assessment General Discussion

a. ACA Description

In simple terms, ACA involves the use of condition inspection data to estimate the remaining serviceable life of physical assets. Utilities periodically inspect physical assets to monitor signs of degradation (e.g. visible corrosion) that can lead to asset failure. Inspection data on its own is useful in identifying and prioritizing assets for maintenance, refurbishment, or replacement. An ACA augments inspection data for assets by processing such data to arrive at a health index ("HI") score that represents an asset's remaining useful life.

b. ACA in Asset Management

Utilities use ACA results to gain insight into the likelihood that major assets will fail over time. This helps with anticipating failures and failure rates, and to plan and budget for the investments needed to maintain or improve system performance in light of asset failure risk.

Toronto Hydro uses condition information to support tactical and strategic investment planning decisions. Planners use inspection data and individual HI scores – in combination with other information and professional judgement – to prioritize assets for tactical intervention in the short- to medium-term. This includes identifying priority deficiencies that require reactive or corrective action, and prioritizing assets for planned renewal projects in a given budget period. At a strategic level, Toronto Hydro uses ACA results to examine condition demographics and trends within major asset classes. ACA results for a particular asset class are grouped into five HI bands that represent key stages of an asset's lifecycle, ranging from new or like new condition to the stage where asset degradation is significant enough to warrant urgent attention. This information supports the development of longer-term investment plans within the annual Investment Planning & Portfolio Reporting Process ("IPPR").

When applied across an asset class, HI scores can be an effective leading indicator of future failure rates within that class and, as an extension, an effective leading indicator of future reliability performance and other outcomes driven by asset failure. Investing at a pace that allows the utility to maintain or, where appropriate, improve the condition demographics for an asset class is an important means of ensuring consistent and predictable performance over the long-term (as measured by lagging indicators like system average reliability performance).

Along with, or in the absence of condition information, age-based probability of failure analysis is a key input to the prioritization of assets for intervention and the forecasting of system-wide performance. Asset age is also typically a significant factor in the calculation of HI scores, partly due to the fact that age bears a strong statistical relationship with probability of failure. The extent to which a utility can monitor significant degradation characteristics that are predictive of asset failure varies depending on the type of asset. Even when the utility is able to monitor a number of condition variables that are strongly predictive of an asset's remaining life, it remains necessary to include age as an ACA variable.

c. Legacy Approach - Weighted Arithmetic Summation Model

Prior to 2017, Toronto Hydro used a weighted arithmetic summation model to calculate HI scores. This methodology assigns specific weights to a number of condition parameters reported during field inspections, sums the results, and calculates the weighted arithmetic mean to compute an HI score along a continuum of potential HI values. For reporting purposes, assets are then placed into five HI categories or bands, from "very good" condition to "very poor" condition. This ACA methodology was the first to be employed by utilities in Ontario and has become the default approach to ACA in the sector.

Toronto Hydro has relied on this model as an indicator of failure risk and a leading indicator of future asset performance to help guide prudent investment planning decisions in the short- to medium-term. While the model has generally proven fit for this purpose, Toronto Hydro's experience over the last eight years has, in the utility's view, revealed certain limitations in relation to: (1) short- to medium-term planning capabilities; and (2) emerging expectations that utilities be able to demonstrate a relationship between the health of assets and investment planning objectives over longer planning horizons. These limitations are outlined in the following sections.

(i) Weak Relationship between Health Scores and Probability of Failure

The weighted arithmetic summation model lacked a formal, mathematical link between the condition of an asset and its probability of failure. Put another way, the legacy model did not allow the utility to toggle between an asset's health score and its probability of failure. The legacy model computed a weighted health score, which is useful for assessing the overall condition of an asset relative to a new asset, and the health of assets relative to each other. As mentioned above, assets were placed into five condition categories based on the HI, from best condition to worst condition. While these different categories could be assigned a suggested range of time to replacement (e.g. an asset in "very poor" condition may generally need to be addressed in one to two years), these ranges were based primarily on engineering judgement and did not provide a precise analytical basis for assessing asset risk and more precise replacement needs based on condition.

A second limitation of the legacy model is that it can struggle to provide a meaningful link to probability of failure. Over time, Toronto Hydro has observed that the weighted arithmetic summation methodology does not consistently provide an accurate representation of asset health degradation. In the weighted summation model, critical conditions that can lead to total asset failure, even if assigned a higher weighting, can be masked by the combination of all other benign condition attributes. This dynamic dilutes the relationship between the HI scores and asset failure risk, with a structural bias toward understating the magnitude of deterioration in an asset's health. For short-term planning horizons (i.e. one to two years), this limitation is not a significant concern, as Toronto Hydro's planners tend to rely directly on condition information from field inspection reports, augmented by other information and professional judgement, to make tactical decisions regarding which assets to prioritize for intervention. However, over the medium- to long-term, a weak relationship between HI scores and asset failure risk can be problematic for strategic investment planning, including longer-term risk and performance management.

As such, Toronto Hydro concluded that alternative ACA approaches needed to be explored to address these concerns while offering additional functionality.

(ii) Data Exclusions and Lack of Projection Capabilities

Another shortcoming of the legacy model was its inability to model the future condition of assets. In regulatory jurisdictions where condition analysis plays a key role in longer-term planning (e.g. the U.K., where regulatory planning horizons are eight years long), the ability to model the asset condition demographics for an asset class at a future point in time is an important means of assessing the pacing and effectiveness of a utility's investment plans. While Toronto Hydro's weighted arithmetic summation model was able to provide condition demographics based on the most recent condition inspections, it was difficult to draw meaningful conclusions from this data about the appropriate pacing of investment over a planning horizon of five years or more.

A related limitation of the legacy model is the model's rejection of assets that lack a minimum amount of condition data. Specifically, the model is not considered reliable if less than 60% of the condition data for an asset is available. This has, in practice, resulted in the exclusion of a large number of assets from the overall ACA sample within an asset class, even if the available condition data for those assets suggests significant degradation (another reason why planners tend to rely on raw inspection information when making short-term planning decisions). While Toronto Hydro, through the use of tablets and improved inspection forms, is continuously improving its asset condition inspection data, the utility nonetheless needs to be able to have a maximally comprehensive view of the condition of its assets based on available data.

d. Decision to Adopt a New ACA Approach

Toronto Hydro continuously seeks opportunities to improve its analytical capabilities and to progress towards best-in-class asset management practices. Due to the limitations discussed above, Toronto Hydro decided in 2016 to take the next step with its ACA by moving to a new methodology. The need to prioritize ACA enhancements was further underscored by the increasing regulatory emphasis on the link between asset condition, probability of failure, and longer-term system investment needs as expressed in five-year utility system plans. The following section discusses Toronto Hydro's selection of the CNAIM and the benefits of that model.

3. Selection of CNAIM for ACA

Toronto Hydro reviewed the ACA methodologies used in Ontario and confirmed that utilities continue to rely mainly on the weighted arithmetic summation methodology, with slight variations in approach. Looking outside of Ontario, Toronto Hydro ultimately gravitated to the CNAIM used by the Office of Gas and Electricity Markets ("Ofgem") and the United Kingdom's distribution network operators. This methodology was developed collaboratively by the network operators regulated by Ofgem and other industry experts, and benefited from the sponsorship and guidance of Ofgem. The methodology was submitted to Ofgem for initial approval in July 2015 and was further refined following public consultation. In February 2016, Ofgem approved the model and directed all network operators to use CNAIM in the 2015-2023 rate-setting period. Additional refinements and enhancements have occurred since this time.

Ofgem describes CNAIM as "a common framework of definitions, principles and calculation methodologies […] for the assessment, forecasting and regulatory reporting of Asset Risk."[1] Toronto Hydro took particular interest in this model specifically because it was developed collaboratively by large, mature and heavily urbanized utilities, in consultation with their regulator and the public, in an advanced performance-based regulatory jurisdiction with an even longer rate-setting period than that of Ontario. The methodology's ability to support rigorous assessment of condition-based probability of failure over an eight-year horizon was appealing to Toronto Hydro for a number of reasons, including the Ontario Energy Board's increasing emphasis on similar evaluation frameworks and principles as a means of supporting Renewed Regulatory Framework objectives and outcomes.

[1] Ofgem. (2017, January 30). *DNO Common Network Asset Indices Methodology Version 1.1.* Online https://www.ofgem.gov.uk/system/files/docs/2017/05/dno_common_network_asset_indices_methodology_v1.1.pdf

The primary benefits of CNAIM with respect to assessing asset health and probability of failure are expected to be as follows:

i. a robust scoring methodology that emphasizes deficiencies which directly impact equipment failure;
ii. fewer asset exclusions due to data availability;
iii. a stronger and more objective relationship between condition and probability of failure; and
iv. the ability to project future asset health scores, providing strategic insight into longer-term investment strategies using forecasted HI demographics.

To date, Toronto Hydro has implemented the aspects of CNAIM necessary to immediately achieve the benefits described in items (i), (ii) and (iv) above. For item (iii), Toronto Hydro is currently in the process of developing the formulas required to convert an HI score produced by CNAIM into a probability of failure.

Asset health and probability of failure are only one part of the CNAIM. The full methodology also addresses consequences of failure and asset criticality. This includes a common methodology for assigning monetized risk values to assets based on consequences of failure – a concept that is analogous to the avoided risk cost methodology in Toronto Hydro's existing Feeder Investment Model ("FIM").

Toronto Hydro's immediate objective in moving to CNAIM was to replace the functionality of the previous ACA, which did not include a consequence of failure or asset criticality component. Going forward, in addition to developing the incremental capability to convert an HI score to probability of failure, Toronto Hydro intends to explore the consequence of failure and criticality aspects of CNAIM. It will also examine opportunities to derive additional value from the existing FIM by connecting it with, or subsuming it within, the CNAIM approach to asset risk evaluation.

The following section describes Toronto Hydro's implementation of the CNAIM to date.

4. Toronto Hydro's Implementation of CNAIM

a. Formulation of ACA

1. Formulas

To date, Toronto Hydro's implementation of CNAIM has covered the derivation of current and future health calculations. Using the CNAIM framework, the current health of an asset is represented by a health score using a continuous scale between 0.5 and 10 (extended up to 15 for forecasting of future health), where 0.5 represents the condition expected of a new asset. A health score of 5.5 represents the point in an asset's life beyond which significant deterioration is likely to be observed. A health score of 10 represents an asset in a state unacceptable to Toronto Hydro.

The steps for deriving current and future health scores in the CNAIM framework include the following (Appendix A of this report provides additional details on the algorithm and each of the variables):

- Calculate an *Initial Health Score* based on the asset's age and expected life, taking into account its operational use (duty) and operating conditions.
- Determine the *Health Score Modifier* based on the known conditions of the asset, including information gathered from inspections the asset, diagnostic tests or measurements. The observed and measured condition inputs are used to determine the *Health Score Factor*, *Health Score Cap* and *Health Score Collar*.
- Determine *Reliability Modifier*, where applicable for the asset's subcategory to account for generic issues affecting asset health or reliability associated with a specific manufacturer or model type. The *Reliability Modifier* comprises a *Reliability Factor* and a *Reliability Collar*.
- Calculate the *Current Health Score* by multiplying the *Initial Health Score* by the *Health Score Factor* and the *Reliability Factor,* and applying the upper and lower thresholds defined by the *Health Score Cap* and *Health Score* and *Reliability Collars*.
- Generate the *Future Health Score* by inputting results into an equation that projects the asset's condition at a desired point in time.

For the purpose of reporting, the *Current* and *Future Health Scores* are mapped onto one of five HI Bands as follows, with *Current Health Score* represented on a continuous scale of 0.5 – 10 and *Future Health Score* represented on a continuous scale of 0.5 – 15:

Table 1: Health Index bands

HI Band	Lower Limit of Health Score	Upper Limit of Health Score	Definition
HI1	≥ 0.5	< 4	New or good condition
HI2	≥ 4	< 5.5	Minor deterioration; in serviceable condition
HI3	≥ 5.5	< 6.5	Moderate deterioration; requires assessment and monitoring
HI4	≥ 6.5	< 8	Material deterioration; consider intervention
HI5 (Current Health)	≥ 8	≤ 10	End of serviceable life; intervention required
HI5 (Future Health)	≥ 8	≤ 15	

2. Data Inputs

The data inputs required to calculate *Current* and *Future Health Scores* for an asset include age and condition and operation data. Condition data includes observations and test results recorded during routine maintenance and field inspections. Asset operation data relates to the use of the asset and varies based on the type of asset (e.g. percent utilization for transformers and number of operations for circuit breakers).

3. Differences between Ofgem and Toronto Hydro implementations of CNAIM

The Ofgem CNAIM model was built around 25 asset types that are common among U.K. utilities. In many cases, the manufacturing and functional characteristics of these assets differ from Toronto Hydro's assets. It was therefore necessary in Toronto Hydro's implementation of the CNAIM approach to adjust certain input factors and initial condition scores to accurately reflect the utility's system and operating realities. The two main areas included:

- adjustments to the caps and collars for each failure mode of an asset to reflect Toronto Hydro's experience with asset deficiencies and failures on its own system; and
- adjustments to duty values, i.e. the loading on an asset or the frequency with which it is used, to reflect the functionality and the way the asset is used in Toronto Hydro's operating context.

In making these necessary utility-specific adjustments, Toronto Hydro did not fundamentally alter or deviate from the core principles or methodology of CNAIM.

Toronto Hydro is exploring additional opportunities to align its implementation of CNAIM with the utility's operational reality. For example, environmental and climate conditions in the U.K. are different from those in Toronto. Toronto Hydro is currently working on developing appropriate location factors which will better define the environment in which the assets are functioning. In the interim, the location factor values are currently defaulted to a value of one, which is consistent with the CNAIM model for situations where the data is not available.

4. Third-party review of Toronto Hydro's CNAIM implementation

To ensure the appropriate implementation of the CNAIM model, including the validity of the aforementioned utility-specific adjustments, Toronto Hydro retained U.K. firm EA Technology to review its newly developed asset health models, recommend areas for improvement, and provide guidance and training to ensure organizational alignment with the asset management philosophy, principles and practices underpinning the CNAIM approach. Toronto Hydro selected EA Technology for this task as they are the foremost experts in the CNAIM model, having provided support for the development of the original methodology as well as the delivery and implementation of the common models to all U.K. distribution network operators.

The following section provides additional details on Toronto Hydro's approach to CNAIM implementation.

b. Approach to implementation

Through its Reliability Centred Maintenance ("RCM") framework, Toronto Hydro categorizes the failure modes and deficiencies for each asset type and documents maintenance strategies for mitigating deficiencies. The utility used RCM information to build the Health Score Modifiers – i.e. the observable and measurable condition variables that modify the health score of an asset – for each asset type modeled in the CNAIM. Unlike Toronto Hydro's legacy ACA methodology, the CNAIM is fully aligned with Toronto Hydro's RCM, meaning that the likelihood that condition variables required by the new ACA model will not be captured during field inspections is low. For more information on Toronto Hydro's RCM, refer to Exhibit 2B, Section D1.2.2.4 and Section D3.1.1.1.

Toronto Hydro determined the condition variables for each asset class based on the following criteria: deficiencies that lead to an asset failure; deficiencies that lead to a component of the asset failing; and deficiencies that degrade the performance of an asset but do not lead to an immediate asset or component failure. The utility performed a comparative analysis of these condition points and assigned appropriate calibration values.

RCM was critical to Toronto Hydro's determination of minimum health score limits in CNAIM, known as "collars." If a deficiency that has a collar is noted during an inspection, the CNAIM algorithm checks to see if the final health score value is above the collar value. If the value is not above the collar value, then the health score is replaced with the collar value. In this way, the severity of any deficiency which may lead to asset failure is not dampened by the appearance of less or no degradation for other condition variables. This eliminates one of the limitations of Toronto Hydro's legacy ACA methodology discussed above.

A detailed technical explanation of the CNAIM model, algorithms, and Toronto Hydro's implementation of those algorithms can be found in Appendix A to this document.

c. Implementation Progress to Date

Toronto Hydro has implemented both the *Current Health Score* and *Future Health Score* for the asset classes listed in Tables 2 and 3, below. Table 2 summarizes the *Current Health Score* demographics for each asset class and Table 3 summarizes the *Future Health Score* demographics for these assets in 2024 assuming no interventions.

Table 2: Summary of Current Health Index Distribution.

Asset Class	Current Health Score				
	HI1	HI2	HI3	HI4	HI5
Overhead Gang-Operated Switches	854	27	76	3	9
SCADA-Mate Switches	1,084	1	26	0	8
Wood Poles	68,425	5,777	20,915	10,877	1,074
4kV Oil Circuit Breakers (MS)	36	4	123	24	0
KSO Circuit Breakers (TS)	10	7	11	11	1
SF6 Circuit Breakers (TS)	130	6	18	3	3
Vacuum Circuit Breakers (MS & TS)	578	46	13	2	29
Air Magnetic Circuit Breakers (MS & TS)	145	90	247	21	53
Airblast Circuit Breakers (MS & TS)	15	9	206	1	3
Station Power Transformers	83	77	61	13	8
Network Transformers	1,334	255	166	60	7
Network Protectors	1,086	185	319	74	26
Cable Chambers	8,112	1,162	1,350	398	89
Submersible Transformers	7,816	588	271	172	55
Air-Insulated Padmount Switches	404	20	73	30	45
Vault Transformers	6,807	4,315	450	214	45
Underground Vaults (combined)	1,017	186	72	12	29
ATS Vaults	8	0	0	0	0
CLD Vaults	21	0	0	0	0
CRD Vaults	9	0	1	0	0
Network Vaults	322	120	63	11	29
Submersible Switch Vaults	115	5	0	0	0
URD Vaults	542	61	8	1	0
Padmount Transformers	5,547	656	283	113	18
SF6-Insulated Padmount Switches	402	0	2	0	6
SF6-insulated Submersible Switches	353	14	7	3	19
Air-Insulated Submersible Switches	755	79	27	7	0

Table 3: Summary of Future Health Index in 2024.

Asset Class	Future Health Score (2024)				
	HI1	HI2	HI3	HI4	HI5
Overhead Gang-Operated Switches	712	135	22	41	59
SCADA-Mate Switches	1,015	43	27	0	34
Wood Poles	59,851	8,767	4,177	17,449	16,824
4kV Oil Circuit Breakers (MS)	36	0	6	119	26
KSO Circuit Breakers (TS)	1	9	7	10	13
SF6 Circuit Breakers (TS)	127	3	4	5	21
Vacuum Circuit Breakers (MS & TS)	575	3	5	54	31
Air Magnetic Circuit Breakers (MS & TS)	97	48	57	277	77
Airblast Circuit Breakers (MS & TS)	3	12	21	194	4
Station Power Transformers	75	25	58	62	22
Network Transformers	1,153	173	229	102	165
Network Protectors	1,027	57	47	177	382
Cable Chambers	6,829	1,546	1,931	327	478
Submersible Transformers	7,447	364	537	143	411
Air-Insulated Padmount Switches	371	30	20	6	145
Vault Transformers	5,397	1,623	3,910	491	410
Underground Vaults (combined)	960	70	162	85	39
ATS Vaults	7	1	0	0	0
CLD Vaults	21	0	0	0	0
CRD Vaults	7	2	0	1	0
Network Vaults	273	55	103	76	38
Submersible Switch Vaults	113	7	0	0	0
URD Vaults	539	5	59	8	1
Padmount Transformers	5174	345	605	227	266
SF6-Insulated Padmount Switches	402	0	0	0	8
SF6 insulated Submersible Switches	346	9	12	4	25
Air Insulated Submersible Switches	710	55	69	23	11

Toronto Hydro does not produce health scores for all major asset classes. The exclusion of an asset class from the ACA is typically due to one of two reasons: (1) it is technically infeasible to collect condition data without damaging the asset; or (2) Toronto Hydro has not developed or fully carried out an advanced inspection program that will provide the inputs necessary to calculate the health score.

Underground cables are an example of the first case described above. Historically, Toronto Hydro has not introduced a cable testing program because the testing methods themselves would shorten the life of the asset. More recently, Toronto Hydro has adopted a new approach and is in the process of implementing it. If successful, the utility will consider using cable testing information to develop an ACA algorithm for cables.

Pole top transformers are an example of an asset for which Toronto Hydro does not presently have a sufficiently advanced, dedicated inspection program. Toronto Hydro performs a cursory inspection of pole top transformers during routine overhead line patrols, checking for any major, readily visible deficiencies. These defects are noted for consideration in reactive and corrective program planning, but the data is not substantial enough to form the basis of a complete ACA algorithm.

d. ACA Integration in CIR Framework

Toronto Hydro's new ACA is a significant part of the utility's 2020-2024 DSP. The utility has leveraged the improved information, including asset condition projections, to help demonstrate the appropriate pacing of planned asset replacement strategies over the forecast period. As mentioned in the introductory sections of this document, a robust ACA can serve as a strong leading indicator of future system performance, including the reliability and safety outcomes that matter most to customers. By gaining better visibility into the overall condition demographics of its major assets, Toronto Hydro has been able to validate and refine its expenditure plans to address assets at a pace that aligns with current and future system needs and customer preferences.

As explained in Section C of the DSP Toronto Hydro has proposed to track and report on a new metric, System Health – Asset Condition (Poles), for the 2020-2024 period. The measure is focused on the percentage of wood poles that are in HI4 or HI5 condition. Since the introduction of an annually reported System Health metric using an adjusted CNAIM methodology is a new development for Toronto Hydro and the Ontario distribution sector in general. As such, additional maturation is still required to enable the projection of Future Health Scores. Toronto Hydro therefore proposes to report on the percentage of wood pole assets in HI4 or H5 category each year through the 2020 to 2024 period and to use the five-year actual data to determine a baseline against which future performance may be measured. This approach is consistent with the OEB's current approach to performance measurement.

e. Areas for Continuous Improvement

(i) Average Age Values

As a step toward refining the accuracy of the model, EA Technology recommended Toronto Hydro undertake a review of its asset useful life values (i.e. minimum expected useful life, maximum expected useful life, and typical useful life for each asset class type). Over time, Toronto Hydro has made minor adjustments to these values based on utility experience, but has not performed a full review of its useful life values (including review of the derivation methodology) since the Kinectrics study performed in 2010.[2] Toronto Hydro intends to update its useful life values and age-based probability of failure curves in the future.

(ii) Location Factor

As mentioned above, the Ofgem algorithm uses location factors values (such as Distance to Coast, Altitude Factor and Corrosion Factor) to determine the expected life of assets. While these factors are suitable to the conditions in the U.K., they may not be suitable for the environmental conditions in Toronto. Toronto Hydro has currently defaulted these values to one and is engaged on developing better condition criteria that will account for the effects of Toronto's environment on the asset deterioration process.

(iii) Reliability Modifier

CNAIM provides for a reliability modifier that can help the utility differentiate subgroups within a specific asset class, e.g. different manufacturers and designs. Currently this has been set to a default neutral value of one. Toronto Hydro requires more information to determine the appropriate scoring of this factor for the algorithm. More data can be collected from field inspections and asset failure resulting in outage events which can be leveraged to develop the reliability modifier.

[2] Kinectrics Inc., *Asset Depreciation Study for the Ontario Energy Board* (July 8, 2010).

Appendix A – Explanation of the Methodology

Introduction

Toronto Hydro's model is similar to Ofgem's CNAIM with minor customizations to fit Toronto Hydro's asset classes. Figure 1 illustrates the methodology, followed by additional details on the major inputs and calculations.

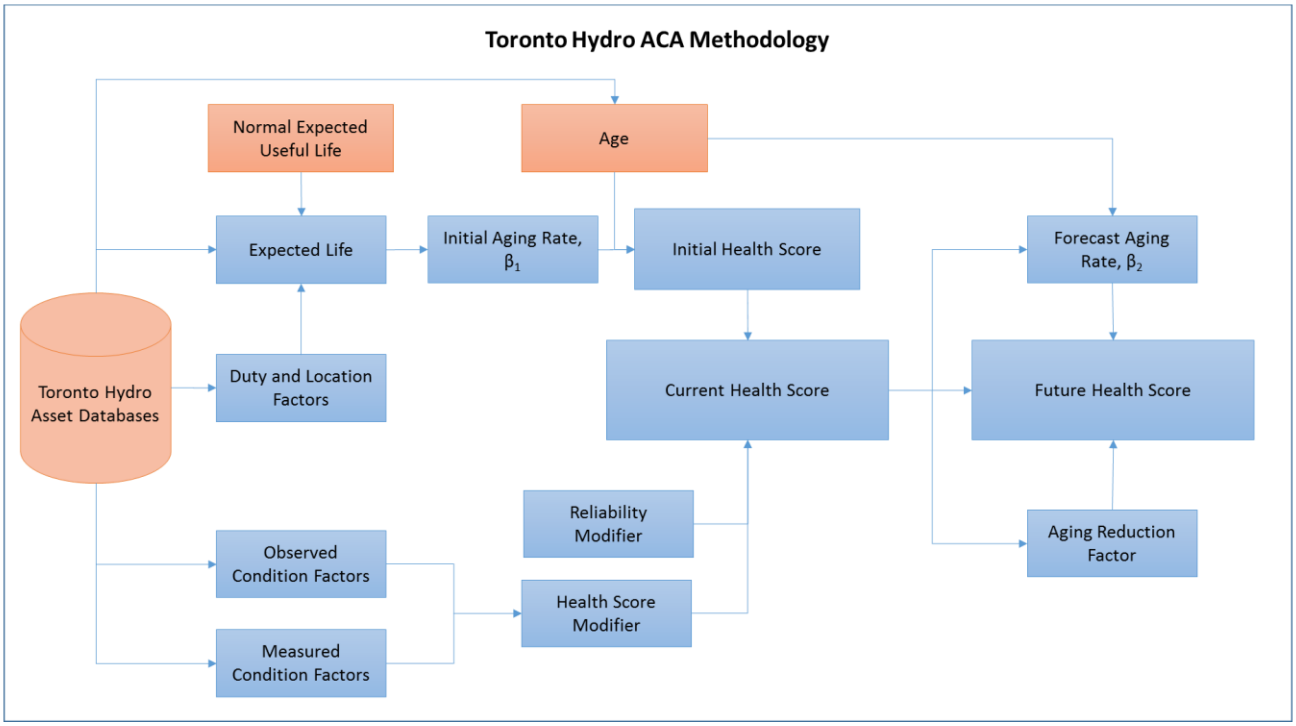


Figure A1: Flow Chart of Toronto Hydro's ACA methodology

Inputs

Inputs such as asset inspection data, nameplate details, location and duty information is provided to the ACA algorithm, from Toronto Hydro's enterprise resource planning (Ellipse) and GIS (GEAR) databases.

Normal Expected Useful Life

The *Normal Expected Useful Life* of an asset is the mid-point between the Minimum and Maximum Useful Life for the asset from the Kinectrics study and is generally aligned with current Toronto Hydro organization-wide practices.

Expected Life

The *Expected Life* of an asset is the *Normal Expected Useful Life* for the asset group adjusted to account for the asset's specific operating conditions (i.e. its environment and the way it is used) as shown in Equation 1.

Eq. 1

$$Expected\ Life = \frac{Normal\ Expected\ Useful\ life}{(Duty\ Factor * Location\ Facor)}$$

Where *Location Factor* and *Duty Factor* are as described below.

Location Factor

Location Factors account for the environmental conditions in which an asset operates. As conditions in Toronto differ from the U.K., factors used by Ofgem are not necessarily suitable for use by Toronto Hydro. Therefore, Toronto Hydro is currently working on developing the *Location Factor* condition criteria for its assets. Currently, the *Location Factor* value is defaulted to one for all assets.

Duty Factor

The *Duty Factor* is applied to account for the fact that the expected life of an asset varies depending on the way it is used, i.e. its duty. The CNAIM allows for an asset to have two different duties, but Toronto Hydro only included one *Duty Factor* based on the available inputs for its assets. Table 4 shows the basis on which *Duty Factors* are assigned for each asset category, as they are defined differently depending on the type of asset. Appendix B provides additional detail on how specific *Duty Factor* values are assigned to assets based on the variables in Table 4.

Table A1: Duty Factor Definitions by Asset Category

Asset Category	Duty Factor 1	Duty Factor 2
Overhead Gang Switches	Normally Opened/Normally Closed	N/A
SCADAMATE R2 Switches	Normally Opened/Normally Closed	N/A
Wood Poles	N/A	N/A
4kV Oil Circuit Breakers	Number of Operations	N/A
KSO Circuit Breakers	Number of Operations	N/A
SF6 Circuit Breakers	Number of Operations	N/A
Vacuum Circuit Breakers	Number of Operations	N/A
Air Magnetic Circuit Breakers	Number of Operations	N/A
Air Blast Circuit Breakers	Number of Operations	N/A
Station Power Transformers	% Utilisation	N/A
Network Transformers	% Utilisation	N/A
Network Protectors	Number of Operations	N/A
Cable Chamber	N/A	N/A
Submersible Transformers	% Utilisation	N/A
Air-Insulated Padmount Switches	N/A	N/A
Vault Transformers	% Utilisation	N/A
Padmount Transformers	% Utilisation	N/A
SF6-Insulated Padmount Switches	N/A	N/A
SF6 insulated Submersible Switches	N/A	N/A
Air Insulated Submersible Switches	N/A	N/A
Underground Vaults	N/A	N/A

Initial Aging Rate, β_1

The aging rate of an asset is modeled based on an exponential curve. The *Initial Aging Rate* is the generic rate at which an asset would be assumed to reach its *Expected Life* adjusted to account for its specific operating conditions, i.e. normalized by its *Expected Life* as shown in Equation 2.

$$\beta 1 = \frac{ln\,(\frac{H_{expected\ life}}{H_{new}})}{Expected\ Life} \qquad \textit{Eq. 2}$$

Where,

- H_{new} is the health score of a new asset and is equal to 0.5.
- $H_{expected}$ life is the health score of the asset when it reached expected life, which is 5.5.
- *Expected Life* is calculated based on Equation 1 above.

Initial Health Score

The *Initial Health Score* is based on a generic exponential relationship to the age and the *Initial Aging Rate* of the asset as shown in Equation 3. The *Expected Life* of the asset determines the shape of the exponential curve through the *Initial Aging Rate*. The *Initial Health Score* only considers the operating conditions and age of an asset and does not consider the current condition of the asset. Therefore, the *Initial Health Score* is capped at a value of 5.5, so that the health score is not purely dependant on age and operating conditions.

$$Initial\ Health\ Score = H_{new} * \ e^{(\beta_1 * age)} \qquad \text{Eq. 3}$$

Where,

- H_{new} is equal to 0.5
- β_1 is the *Initial Aging Rate*
- *Age* is the current age of the asset

Current Health Score

The *Current Health Score* is determined by applying the *Health Score Modifier* and *Reliability Modifier* to the Initial Health Score. These modifiers account for the condition of the asset (*Health Score Modifier*) and any generic issues affecting the probability of failure of certain subcategories (e.g. manufacturer) of assets (*Reliability Modifier*) and are discussed in more detail below. Both modifiers include a factor that is multiplied by the *Initial Health Score* as shown in Equation 4. That product is then checked to ensure that it is within the limits set out by the other elements of the modifiers (cap and collars) according to the logic shown below. The *Current Health Score* has a scale of 0.5 to 10.

$$Current\ Health\ Score\ = Initial\ Health\ Score * Health\ Score\ Factor * Reliability\ Factor \qquad \text{Eq. 4}$$

IF Current Health Score > Health Score Cap
THEN Current Health Score = Health Score Cap

IF Current Health Score < Max (Health Score Collar, Reliability Collar)
THEN Current Health Score= MAX (Health Score Collar, Reliability Collar)

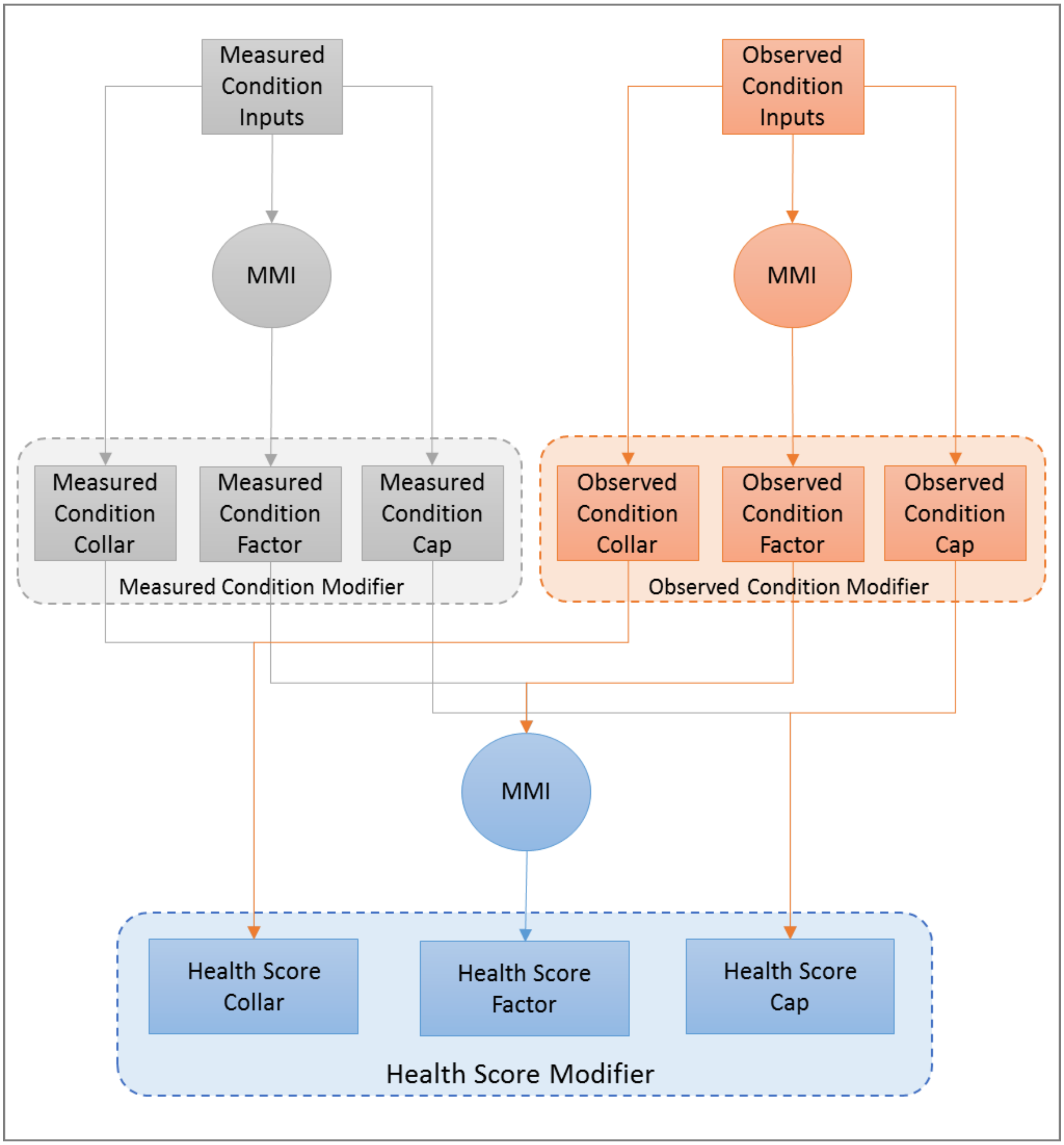
Reliability Modifier

The *Reliability Modifier* is applied to the *Current Health Score* of an asset to account for any subcategories of assets shown to have different probabilities of failure given the same Health Score due to a generic issue that affects health and reliability with respect to the make, type, or construction of the asset. This modifier consists of a *Reliability Factor*, which is multiplied by the *Initial Health Score* (see Equation 4), and a *Reliability Collar*, which defines the minimum value the *Current Health Score* can take.

Currently, for most assets, the *Reliability Factor* is set to a default neutral value of one and there is no *Reliability Collar* as Toronto Hydro needs to collect more information and data on asset failures to implement this modifier. The one exception is for network protectors for which there currently is sufficient information to support the use of different *Reliability Modifier* values, which are provided in Appendix B for the different network protector types (fibretop, submersible, ventilated and semi-dust).

Health Score Modifier

The *Health Score Modifier* is specific to individual assets and is based on the condition of the asset as observed or measured during routine maintenance and field inspections. The *Health Score Modifier* has three elements, including a factor and a collar which are used in the same way as the corresponding elements of the *Reliability Modifier*. It also includes a *Health Score Cap*, which is the maximum allowable value for the *Current Health Score*. As shown in Figure 2, the *Health Score Modifier* is derived from two condition modifiers (*Observed Condition Modifier* and *Measured Condition Modifier*), which also each consist of three elements (factor, cap and collar). The condition modifiers are in turn determined from observed and measured condition inputs as described in more detail below. Note that the *Health Score Modifier* for station transformers is based on three other modifiers (*Oil Test Modifier*, *Dissolved Gas Analysis ("DGA") Test Modifier* and *Furfuraldehyde Analysis ("FFA") Test Modifier*) determined from oil analyses, in addition to the *Observed* and *Measured Condition Modifiers*. This is discussed in more detail at the end of this appendix.



1 **Figure A2 – Process for determining Condition Modifiers and Health Score Modifier.**

The Health Score Factor is determined by combining the Observed Condition Factor and Measured Condition Factor using the Maximum and Multiple Increment ("MMI") technique (see below for details). The Health Score Collar is the maximum of the Observed and Measured Condition Collars and the Health Score Cap is the minimum of the Observed and Measured Condition Caps.

Observed Condition Modifier

The *Observed Condition Modifier* is based on observed conditions such as visual checks or function tests without measurements. It is used in combination with the *Measured Condition Modifier* to derive the *Health Score Modifier* as described above. However, in some cases, for assets that do not have any field measurements, the ACA algorithm considers only the *Observed Condition Modifier* in determining the *Health Score Modifier*.

Like, the *Health Score Modifier*, the *Observed Condition Modifier* consists of a factor, a cap, and a collar. This modifier is determined by combining all of the asset's Observed Condition Inputs, which also each consists of a factor, a cap and a collar, in the same way that the Observed and Measured Condition Modifiers are combined to determine the Health Score Modifier:

- The *Observed Condition Factor* is determined by combining all the *Observed Condition Input Factors* using the MMI Technique.
- The *Observed Condition Cap* is the minimum of all the *Observed Condition Input Caps*.
- The *Observed Condition Collar* is the maximum of all the *Observed Condition Input Collars*.

Each asset class has its own set of *Observed Condition Inputs* based on the available inspection points and impacts of observed deficiencies on the asset. *Observed Condition Inputs* are based on Toronto Hydro analysis of RCM information regarding deficiencies that lead to asset or component failure or to degraded performance. The three elements of each *Observed Condition Input* are assigned values based on the following:

- *Observed Condition Input Factor* – This is the score given to each recorded observed condition. Each condition will have a specific score based on the severity of the deficiency and how it will affect the asset.
- *Condition Input Cap* - This is the upper limit assigned to each observed deficiency. This value is usually 10, which is the upper limit for the Current Health Score.
- *Condition Input Collar* – This is the lower limit assigned to each observed deficiency. Collars are given to each condition deficiency based on how it affects the asset. The use of this collar is intended to prevent the severity of a deficiency that could lead to asset failure from being dampened by the inclusion of other conditions variables for which there is less or no degradation.

Appendix B provides details on how factors, caps and collars are assigned values for each condition of each asset class.

Measured Condition Modifier

The *Measured Condition Modifier* is used and derived in the same way as the *Observed Condition Modifier*, but the *Measured Condition Inputs* are based on measured values from maintenance activities and field inspections (e.g. from failure finding or condition monitoring tests) instead of observed conditions. Furthermore, as measured condition inputs tend to be more accurate, less subjective and better indicators of internal (as opposed to external) issues affecting assets, *Measured Condition Factors* tend to have a higher score than *Observed Condition Factors*.

Maximum and Multiple Increment (MMI) Technique

The MMI technique is used to combine two or more input factors into a single factor such that the value of the final factor is primarily driven by the strongest input factor, supplemented to a lesser and controlled degree by the other input factors (depending on their strength). The ACA methodology uses this technique to determine the *Observed Condition Factor* and *Measured Condition Factor* from multiple condition input factors and to combine the two condition factors to form the *Health Score Factor*.

The final combined factor is the sum of two variables (Var_1 and Var_2), which are based on the input factors.

$$CombinedFactor = Var_1 + Var_2 \qquad \text{Eq. 5}$$

These two variables are determined in one of two ways depending on whether any of the input factors are greater than 1.

If any input factor is greater than 1, then Var_1 is the highest of the input factors and Var_2 is calculated using the remaining highest input factors greater than 1 (up to a maximum) as shown in Equation 7 below.

$$Var_1 = F_1 \qquad \text{Eq. 6}$$

$$Var_2 = \frac{\sum_2^n (F_i - 1)}{FD_1} \qquad \text{Eq. 7}$$

Where:

- F_i represents each of the input factors greater than 1 ranked in descending order such that F_1 is the highest factor, F_2 the second highest, etc.
- n represents the maximum number of total factors contributing to the *Combined Factor* and is a calibration parameter.
- FD_1 represents a constant, *Factor Divider 1*, which specifies the degree to which additional factors are able to influence the *Combined Factor*.

If all the factors are less than or equal to 1, then Var_1 is the lowest of the input factors and Var_2 is based on the second lowest as shown in Equation 9.

$$Var_1 = F_1 \qquad \text{Eq. 8}$$

$$Var_2 = \frac{F_2 - 1}{FD_2} \qquad \text{Eq. 9}$$

Where,

- F_1 represents the lowest input factor and F_2 the second lowest.
- FD_2 represents a constant, *Factor Divider 2*, which specifies the degree to which the second input factor is able to influence the *Combined Factor*.

Forecast Aging Rate, β_2

The *Forecast Aging Rate* is used to relate the *Future Health Score* to the *Current Health Score*. It is based on the condition of the asset (through the *Current Health Score*) and the age of the asset as shown in Equation 10. The *Forecast Aging Rate* is capped at less than twice the value of the *Initial Aging Rate* (β_1) calculated using Equation 2. This is to prevent unrealistically high rates of deterioration being applied to relatively new assets where reliability issues have been identified early on in their life.

$$\beta_2 = \frac{ln\left(\frac{\text{Current Health Score}}{H_{new}}\right)}{\text{Age}} \qquad \text{Eq. 10}$$

Where,

- *Age* is current age of the asset

  Current Health Score is the value calculated for the asset using Equation 4.

Future Health Score

Like the *Initial Health Score*, the *Future Health Score* is based on an exponential equation (see Equation 11). In this case, it is based on the current condition of the asset (as reflected by *Current Health Score*) and the shape of the curve is determined by the *Forecast Aging Rate* (modified by the *Aging Reduction Factor* as discussed below). The *Future Health Score* is capped at 15.

$$Future\ Health\ Score = Current\ Health\ Score\ *\ e^{(\frac{\beta_2}{r})*t)} \qquad \text{Eq. 11}$$

Where,

- *t* is the number of years into the future for which the *Future Health Score* is to be calculated
- β_2 is the *Forecast Aging Rate* calculated using Equation 10
- *r* is the *Aging Reduction Factor* described below

Aging Reduction Factor, r

As the *Future Health Score* is modeled using an exponential curve, assets with a high *Current Health Score* may have a high *Forecast Aging Rate*. For assets reaching end of life ("EOL"), this can result in a run-away effect in the *Future Health Score*, which would not reflect the deterioration that is observed in real life.

The *Aging Reduction Factor* is introduced to reduce the potential overstatement of the *Future Health Score* by flattening the exponential curve to a degree determined by the *Current Health Score* as shown in Table 5.

Table A2: Aging Reduction Factors

Current Health Score	Aging Reduction Factor
<2	1
2 to 5.5	(Current Health Score -2)/7) + 1
>5.5	1.5

Additional Condition Modifiers for Station Power Transformers

Due to their larger size and rating compared to distribution transformers and the availability of extra information available from oil analyses, three additional modifiers are used in combination with the *Observed* and *Measured Condition Modifiers* to determine the *Health Score Modifier* for station power transformers. The *Oil Test Modifier*, *DGA Test Modifier* and *FFA Test Modifier* also each consist of a factor, cap and collar and these values are determined from oil test results in a manner similar to that used to determine the *Measured Condition Modifier* from *Measured Condition Inputs*. The cap for each of these modifiers is set to 10. Additional details on the modifiers are provided below.

Oil Test Modifier

The *Oil Test Modifier* provides additional information on the condition of a station power transformer. The *Oil Test Factor* is determined using information from moisture content, acidity and breakdown strength tests of the oil. These results are grouped into three categories based on IEEE Std. C57.106-205.

The values for the *Oil Test Factors* and *Oil Test Collars* are assigned based on these categories as detailed in Appendix B.

DGA Test Modifier

The *DGA Test Modifier* is based on the dissolved gas content of the oil. This information can be used to detect abnormal electrical or thermal activity within the asset.

Of the gases measured during DGA, only the results for hydrogen, methane, ethylene, ethane and acetylene are used to derive the *DGA Test Modifier*. The DGA results for each of these gases are classified into standard scores based on IEEE Std. C57.104-2008. The formulas used to calculate the components of the *DGA Test Modifier* as shown below are in line with the Ofgem CNAIM.

The scores for the aforementioned five gases are multiplied by values relative to the importance of the quantity of each gas measured, and summed to create a DGA Score as shown below.

$$DGA\ Score = 50Hydrogen\ Score + 30Methane\ Score + 30Ethylene\ Score + 30Ethane\ Score + 120Acetylene\ Score \qquad \text{Eq. 12}$$

The *DGA Test Collar* is determined by dividing the DGA Score by 220 to get a value between 1 and 10. This will result in a minimum *Current Health Score* of at least 7 for an asset when DGA levels are indicative of severe degradation.

The *DGA Test Factor* is determined by comparing the current DGA Score with historical results for the same asset. The percentage change is calculated using the following formula:

$$\%\ Change = \frac{DGA\ Score_{latest} - DGA\ Score_{previous}}{DGA\ Score_{previous}} * 100\% \qquad \text{Eq. 13}$$

The value of the percentage change is categorized into five bands (negative, neutral, small, significant or last) and factors assigned based on the percentage change as detailed in Appendix B.

FFA Test Modifier

The *FFA Test Modifier* is determined from the level of furfuraldehyde in the oil, providing an indication of the extent to which the paper insulation of the transformer windings has deteriorated.

The *FFA Test Collar* is calculated using the following empirical relationship:

$$FFA\ Test\ Collar = 2.33\ \ S^{0.68} \qquad \text{Eq. 14}$$

Where *S* is the FFA value in ppm.

The FFA value is divided into five categories and the *FFA Test Factors* assigned based on those categories as detailed in Appendix B.

Appendix B – Duty Factor Values and Condition Factor Parameters

(i) Duty Factor Values

Table B1: Distribution Transformers

Max % Utilisation under normal operating conditions	Duty Factor
<= 50%	0.9
> 50% and <= 70%	0.95
> 70% and <= 100%	1
> 100%	1.4
Default	1

Table B2: Network Protectors

Number of operations	Duty Factor
<= 1000	0.9
> 1000 and <= 2000	0.95
> 2000 and <= 3000	1
> 3000 and <= 5000	1.3
> 5000	1.4
Default	1

Table B3: Station Power Transformers

Max % Utilisation under normal operating conditions	Duty Factor
<= 50%	1
> 50% and <= 70%	1.05
> 70% and <= 100%	1.1
> 100%	1.4
Default	1

Table B4: Station Circuit Breakers

Number of operations	Duty Factor
Normal/Low (1<10000 operations)	1
High (10000+ operations)	1.2
Default	1

Table B5: Overhead Switches

Usage	Duty Factor
Normally Open	1
Normally Closed	1.2
Default	1

(ii) Observed Condition Factors

Submersible Transformers

Table B6: Submersible Transformers – External Condition of Tank (Lid and Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.15	10	5.5
Very Poor	1.35	10	7
Default	1	10	0.5

Table B7: Submersible Transformers – Oil Leak (Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.25	10	7
Poor	1.35	10	8
Very Poor	1.5	10	9
Default	1	10	0.5

1 **Table B8: Submersible Transformers – Connection Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As new	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.12	10	0.5
Substantial Deterioration	1.25	10	0.5
Default	1	10	0.5

2 **Table B9: Submersible Transformers – External Condition of Tank (Transformer Body)**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.02	10	0.5
Poor	1.1	10	4
Very Poor	1.2	10	6.5
Default	1	10	0.5

3 **Table B9: Submersible Transformers – Oil Leak (Not Base)**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.1	10	4
Poor	1.2	10	5.5
Very Poor	1.25	10	6
Default	1	10	0.5

4 *Vault Transformers*

5 **Table B10: Vault Transformers – External Condition of Tank (Lid and Base)**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.15	10	5.5
Very Poor	1.35	10	7
Default	1	10	0.5

Table B11: Vault Transformers – Oil Leak (Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.25	10	6
Poor	1.35	10	7
Very Poor	1.5	10	9
Default	1	10	0.5

Table B12: Vault Transformers – Connection Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As new	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.12	10	0.5
Substantial Deterioration	1.25	10	0.5
Default	1	10	0.5

Table B13: Vault Transformers – External Condition of Tank (Transformer Body)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.02	10	0.5
Poor	1.1	10	4
Very Poor	1.2	10	6.5
Default	1	10	0.5

Table B14: Vault Transformers – Oil Leak (Not Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.1	10	4
Poor	1.2	10	5.5
Very Poor	1.25	10	6
Default	1	10	0.5

Padmount Transformers

Table B15: Padmount Transformers – Condition of Transformer (Lid and Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.15	10	5.5
Very Poor	1.35	10	7
Default	1	10	0.5

Table B16: Padmount Transformers – Oil Leak (Base)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.25	10	6
Poor	1.35	10	7
Very Poor	1.5	10	9
Default	1	10	0.5

Table B17: Padmount Transformers – Condition of Transformer (Enclosure)

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.15	10	5.5
Very Poor	1.35	10	7
Default	1	10	0.5

Table B18: Padmount Transformers – Connection Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As new	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.12	10	0.5
Substantial Deterioration	1.25	10	0.5
Default	1	10	0.5

1 **Table B19: Padmount Transformers – Condition of Transformer (Transformer Body)**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.02	10	0.5
Poor	1.1	10	4
Very Poor	1.2	10	6.5
Default	1	10	0.5

2 **Table B20: Padmount Transformers – Oil Leak (Not Base)**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.1	10	4
Poor	1.2	10	5.5
Very Poor	1.25	10	6
Default	1	10	0.5

3 *Network Transformers*

4 **Table B21: Network Transformers – External Condition of Tank (Lid and Base)**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.15	10	5.5
Very Poor	1.35	10	7
Default	1	10	0.5

5 **Table B22: Network Transformers – Oil Leak (Base)**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.25	10	6
Poor	1.35	10	7
Very Poor	1.5	10	9
Default	1	10	0.5

1 **Table B23: Network Transformers – Connection Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As new	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.12	10	0.5
Substantial Deterioration	1.25	10	0.5
Default	1	10	0.5

2 **Table B24: Network Transformers – External Condition of Tank (Transformer Body)**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.02	10	0.5
Poor	1.1	10	4
Very Poor	1.2	10	6.5
Default	1	10	0.5

3 **Table B25: Network Transformers – Oil Leak (Not Base)**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.1	10	4
Poor	1.2	10	5.5
Very Poor	1.25	10	6
Default	1	10	0.5

4 **Table B26: Network Transformers – Primary Switch Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.2	10	0.5
Substantial Deterioration	1.3	10	6.5
Default	1	10	0.5

Network Protectors

Table B27: Network Protectors – Gasket/Seal Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Satisfactory	1	10	0.5
Not Satisfactory	1.2	10	5.5
Default	1	10	0.5

Table B28: Network Protectors – Protector External Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.1	10	4
Very Poor	1.2	10	5.5
Default	1	10	0.5

Table B29: Network Protectors – Internal Flood Water Stains

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Satisfactory	1	10	0.5
Not Satisfactory	1.3	10	6.5
Default	1	10	0.5

Table B30: Network Protectors – Protector External Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No dirt observed during inspection	1	10	0.5
Some dirt observed but cleaned during inspection	1.05	10	0.5
Substantial dirt observed, requires cleaning	1.2	10	0.5
Default	1	10	0.5

1 *Air-Insulated Padmount Switches*

2 **Table B31: Air-Insulated Padmount Switches – Enclosure Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.1	10	5.5
Very Poor	1.3	10	7
Default	1	10	0.5

3 **Table B32: Air-Insulated Padmount Switches – Phase Barriers Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No	1	10	0.5
Missing/damaged	1.35	10	7
Default	1	10	0.5

4 **Table B33: Air-Insulated Padmount Switches – Arc Suppressors Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No	1	10	0.5
Missing/damaged	1.3	10	0.5
Default	1	10	0.5

5 **Table B34: Air-Insulated Padmount Switches – Connection Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As new	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.05	10	0.5
Substantial Deterioration	1.2	10	0.5
Default	1	10	0.5

6 **Table B35: Air-Insulated Padmount Switches – Switch Blade Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No	1	10	0.5
Missing/damaged	1.4	10	8
Default	1	10	0.5

1 *SF6-Insulated Padmount Switches*

2 **Table B36: SF6-Insulated Padmount Switches – Enclosure Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.1	10	5.5
Very Poor	1.3	10	7
Default	1	10	0.5

3 **Table B37: SF6-Insulated Padmount Switches – Gas Leak**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Gas Pressure Gauge Color: Green	1	10	0.5
Gas Pressure Gauge Color: Red	1.4	10	8
Default	1	10	0.5

4 **Table B38: SF6-Insulated Padmount Switches – Connection Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.05	10	0.5
Substantial Deterioration	1.2	10	0.5
Default	1	10	0.5

5 *Air-Insulated Submersible Switches*

6 **Table B39: Air-Insulated Submersible Switches – External Condition of Switch**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.1	10	5.5
Very Poor	1.3	10	7
Default	1	10	0.5

1 **Table B40: Air-Insulated Submersible Switches – Phase Barrier Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No	1	10	0.5
Missing/damaged	1.35	10	7
Default	1	10	0.5

2 **Table B41: Air-Insulated Submersible Switches – Connection Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As new	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.05	10	0.5
Substantial Deterioration	1.2	10	0.5
Default	1	10	0.5

3 **Table B42: Air-Insulated Submersible Switches – Internal Flood Water Stains**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No	1	10	0.5
Missing/damaged	1.3	10	6.5
Default	1	10	0.5

4 *SF6-Insulated Submersible Switches*

5 **Table B43: SF6-Insulated Submersible Switches – Enclosure Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Deterioration	1.05	10	0.5
Poor	1.1	10	5.5
Very Poor	1.3	10	7
Default	1	10	0.5

6 **Table B44: SF6-Insulated Submersible Switches – Gas Leak**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Gas Pressure Gauge Color: Green	1	10	0.5
Gas Pressure Gauge Color: Red	1.4	10	8
Default	1	10	0.5

Table B45: SF6-Insulated Submersible Switches – Connection Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Normal Wear	1	10	0.5
Some Deterioration	1.05	10	0.5
Substantial Deterioration	1.2	10	0.5
Default	1	10	0.5

Wood Poles

Table B46: Wood Poles – Pole Leaning

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Lean	1	10	0.5
Slight Lean	1.01	10	0.5
Moderate Lean	1.05	10	0.5
Extensive Lean	1.1	10	4
Default	1	10	0.5

Table B47: Wood Poles – Pole Base Rot

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Pole Base Rot	1	10	0.5
Slight Pole Base Rot	1.1	10	0.5
Moderate Pole Base Rot	1.15	10	4
Extensive Pole Base Rot	1.2	10	6
Default	1	10	0.5

Table B48: Wood Poles – Pole Void

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Pole Void	1	10	0.5
Slight Pole Void	1.1	10	0.5
Moderate Pole Void	1.15	10	4
Extensive Pole Void	1.2	10	6
Default	1	10	0.5

1 **Table B49: Wood Poles – Bird/Animal Damage**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Animal Damage	1	10	0.5
Slight Animal Damage	1.05	10	0.5
Moderate Animal Damage	1.1	10	4
Extensive Animal Damage	1.15	10	5.5
Default	1	10	0.5

2 **Table B50: Wood Poles – Pole Separation**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Pole Separation	1	10	0.5
Slight Pole Separation	1.1	10	0.5
Moderate Pole Separation	1.15	10	4
Extensive Pole Separation	1.2	10	6
Default	1	10	0.5

3 *Station Power Transformers*

4 **Table B51: Station Power Transformers – Oil Leak (Base)**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.25	10	0.5
Poor	1.35	10	7
Very Poor	1.5	10	9
Default	1	10	0.5

5 **Table B52: Station Power Transformers – Oil Leak (Not Base)**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.9	10	0.5
Good	1	10	0.5
Slight Leak	1.1	10	0.5
Poor	1.2	10	6
Very Poor	1.25	10	7
Default	1	10	0.5

Overhead Gang-Operated Switches

Table B53: Overhead Gang-Operated Switches – Interphase Operator Link

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B54: Overhead Gang-Operated Switches – Operation Handle

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some deterioration	1.3	4	10
Substantial deterioration	1.5	8	10
Default	1	0.5	10

Table B55: Overhead Gang-Operated Switches – Insulator

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B56: Overhead Gang-Operated Switches – Stationary Contacts

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B57: Overhead Gang-Operated Switches – Switch Blade

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

1 **Table B58: Overhead Gang-Operated Switches – Switch Base Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

2 **Table B59: Overhead Gang-Operated Switches – Arc Interrupters**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

3 **Table B60: Overhead Gang-Operated Switches – Connection**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.25	8	10
Default	1	0.5	10

4 **Table B61: Overhead Gang-Operated Switches – Ground Connection**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.25	8	10
Default	1	0.5	10

5 **Table B62: Overhead Gang-Operated Switches – Corrosion**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Low Corrosion	1.05	0.5	10
Medium Corrosion	1.25	5.5	10
High Corrosion	1.5	8	10
Default	1	0.5	10

1 *SCADA-Mate R2 Switches*

2 **Table B63: SCADA-Mate R2 Switches – Insulator**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	0.5	10
Partially repaired, follow up required	1.8	8	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

3 **Table B64: SCADA-Mate R2 Switches – Switch Operation Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	0.5	10
Partially repaired, follow up required	1.7	8	10
Substantial Deterioration	1.8	8	10
Default	1	0.5	10

4 **Table B65: SCADA-Mate R2 Switches – Remote Operation Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.35	0.5	10
Partially repaired, follow up required	1.75	8	10
Substantial Deterioration	1.85	8	10
Default	1	0.5	10

5 **Table B66: SCADA-Mate R2 Switches – Ground Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1	0.5	10
Partially repaired, follow up required	1.25	0.5	10
Substantial Deterioration	1.45	0.5	10
Default	1	0.5	10

1 **Table B67: SCADA-Mate R2 Switches – Switch Mounting Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1	0.5	10
Partially repaired, follow up required	1.65	8	10
Substantial Deterioration	1.75	8	10
Default	1	0.5	10

2 **Table B68: SCADA-Mate R2 Switches – Corrosion**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1.15	0.5	10
Low Corrosion	1.45	2.5	10
Medium Corrosion	1.5	5.5	10
High Corrosion	1.6	8	10
Default	1	0.5	10

3 *4kV Oil Circuit Breakers*

4 **Table B69: 4kV Oil Circuit Breakers – Arc Extinguishing Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	0.5	10
Substantial Deterioration	1.25	5.5	10
Default	1	0.5	10

5 **Table B70: 4kV Oil Circuit Breakers – Primary Contact Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	0.5	10
Substantial Deterioration	1.25	5.5	10
Default	1	0.5	10

1 **Table B71: 4kV Oil Circuit Breakers – Arcing Contact Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	0.5	10
Substantial Deterioration	1.25	5.5	10
Default	1	0.5	10

2 **Table B72: 4kV Oil Circuit Breakers – Breaker Mechanical Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	0.5	10
Substantial Deterioration	1.4	8	10
Default	1	0.5	10

3 **Table B73: 4kV Oil Circuit Breakers – Oil Tank Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	0.5	10
Substantial Deterioration	1.4	8	10
Default	1	0.5	10

4 **Table B74: 4kV Oil Circuit Breakers – Trip Mechanism Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	0.5	10
Substantial Deterioration	1.3	8	10
Default	1	0.5	10

5 **Table B75: 4kV Oil Circuit Breakers – Charging Mechanism Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	0.5	10
Substantial Deterioration	1.3	8	10
Default	1	0.5	10

Table B76: 4kV Oil Circuit Breakers – Closing Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	0.5	10
Substantial Deterioration	1.2	5.5	10
Default	1	0.5	10

Table B77: 4kV Oil Circuit Breakers – Anti-Pump Operation Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	0.5	10
Substantial Deterioration	1.2	5.5	10
Default	1	0.5	10

Table B78: 4kV Oil Circuit Breakers – Corrosion

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1.05	0.5	10
Low Corrosion	1.1	4	10
Medium Corrosion	1.15	5.5	10
High Corrosion	1.35	8	10
Default	1	0.5	10

KSO Oil Circuit Breakers

Table B79: KSO Oil Circuit Breakers – Arc Extinguishing Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.15	5.5	10
Default	1	0.5	10

Table B80: KSO Oil Circuit Breakers – Primary Contact Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.15	5.5	10
Default	1	0.5	10

1 **Table B81: KSO Oil Circuit Breakers – Arcing Contact Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.15	5.5	10
Default	1	0.5	10

2 **Table B82: KSO Oil Circuit Breakers – Breaker Mechanical Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	4	10
Substantial Deterioration	1.3	8	10
Default	1	0.5	10

3 **Table B83: KSO Oil Circuit Breakers – Oil Tank Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	4	10
Substantial Deterioration	1.3	8	10
Default	1	0.5	10

4 **Table B84: KSO Oil Circuit Breakers – Oil Condition Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	4	10
Substantial Deterioration	1.3	8	10
Default	1	0.5	10

5 **Table B85: KSO Oil Circuit Breakers – Trip Mechanism Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	4	10
Substantial Deterioration	1.2	6.5	10
Default	1	0.5	10

Table B86: KSO Oil Circuit Breakers – Charging Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	4	10
Substantial Deterioration	1.2	6.5	10
Default	1	0.5	10

Table B87: KSO Oil Circuit Breakers – Closing Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.1	5.5	10
Default	1	0.5	10

Table B88: KSO Oil Circuit Breakers – Anti-Pump Operation Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.1	5.5	10
Default	1	0.5	10

Table B89: KSO Oil Circuit Breakers – Corrosion

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1.1	0.5	10
Low Corrosion	1.15	5.5	10
Medium Corrosion	1.25	6	10
High Corrosion	1.35	8	10
Default	1	0.5	10

Vacuum Circuit Breakers

Table B90: Vacuum Circuit Breakers – Breaker Mechanical Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	4	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

Table B91: Vacuum Circuit Breakers – Trip Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	0.5	10
Substantial Deterioration	1.75	6.5	10
Default	1	0.5	10

Table B92: Vacuum Circuit Breakers – Charging Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	0.5	10
Substantial Deterioration	1.75	6.5	10
Default	1	0.5	10

Table B93: Vacuum Circuit Breakers – Closing Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.55	5.5	10
Default	1	0.5	10

Table B94: Vacuum Circuit Breakers – Anti-Pump Operation Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.55	5.5	10
Default	1	0.5	10

Table B95: Vacuum Circuit Breakers – Corrosion

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1	0.5	10
Low Corrosion	1	0.5	10
Medium Corrosion	1.15	2.5	10
High Corrosion	1.2	4	10
Default	1	0.5	10

1 *Air Magnetic Circuit Breakers*

2 **Table B96: Air Magnetic Circuit Breakers – Arc Extinguishing Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	4	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

3 **Table B97: Air Magnetic Circuit Breakers – Primary Contact Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	4	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

4 **Table B98: Air Magnetic Circuit Breakers – Arcing Contact Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	4	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

5 **Table B99: Air Magnetic Circuit Breakers – Breaker Mechanical Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.6	4	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

6 **Table B100: Air Magnetic Circuit Breakers – Trip Mechanism Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.4	4	10
Substantial Deterioration	1.7	6.5	10
Default	1	0.5	10

1 **Table B101: Air Magnetic Circuit Breakers – Charging Mechanism Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.4	4	10
Substantial Deterioration	1.7	6.5	10
Default	1	0.5	10

2 **Table B102: Air Magnetic Circuit Breakers – Closing Mechanism Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.55	5.5	10
Default	1	0.5	10

3 **Table B103: Air Magnetic Circuit Breakers – Anti-Pump Operation Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.55	5.5	10
Default	1	0.5	10

4 **Table B104: Air Magnetic Circuit Breakers – Corrosion**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1.1	0.5	10
Low Corrosion	1.2	0.5	10
Medium Corrosion	1.25	4	10
High Corrosion	1.3	5.5	10
Default	1	0.5	10

5 *Airblast Circuit Breakers*

6 **Table B105: Airblast Circuit Breakers – Arc Extinguishing Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.4	6.5	10
Default	1	0.5	10

1 **Table B106: Airblast Circuit Breakers – Primary Contact Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.4	6.5	10
Default	1	0.5	10

2 **Table B107: Airblast Circuit Breakers – Arcing Contact Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.4	6.5	10
Default	1	0.5	10

3 **Table B108: Airblast Circuit Breakers – Pressure Relief Valve Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.4	6.5	10
Default	1	0.5	10

4 **Table B109: Airblast Circuit Breakers – Breaker Mechanical Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

5 **Table B110: Airblast Circuit Breakers – Trip Mechanism Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.35	6.5	10
Default	1	0.5	10

1 **Table B111: Airblast Circuit Breakers – Closing Mechanism Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.3	5.5	10
Default	1	0.5	10

2 **Table B112: Airblast Circuit Breakers – Anti-Pump Operation Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.05	4	10
Substantial Deterioration	1.3	5.5	10
Default	1	0.5	10

3 **Table B113: Airblast Circuit Breakers – Corrosion**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1	0.5	10
Low Corrosion	1	0.5	10
Medium Corrosion	1.15	4	10
High Corrosion	1.25	5.5	10
Default	1	0.5	10

4 *SF6 Circuit Breakers*

5 **Table B114: SF6 Circuit Breakers – Breaker Mechanical Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	4	10
Substantial Deterioration	1.8	8	10
Default	1	0.5	10

6 **Table B115: SF6 Circuit Breakers – SF6 Gas Quality**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	4	10
Substantial Deterioration	1.8	8	10
Default	1	0.5	10

Table B116: SF6 Circuit Breakers – SF6 Gas Leaks Detected

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	4	10
Substantial Deterioration	1.8	8	10
Default	1	0.5	10

Table B117: SF6 Circuit Breakers – SF6 Control Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	4	10
Substantial Deterioration	1.8	8	10
Default	1	0.5	10

Table B118: SF6 Circuit Breakers – Trip Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	4	10
Substantial Deterioration	1.7	6.5	10
Default	1	0.5	10

Table B119: SF6 Circuit Breakers – Charging Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	4	10
Substantial Deterioration	1.7	6.5	10
Default	1	0.5	10

Table B120: SF6 Circuit Breakers – Closing Mechanism Deficiency

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.55	5.5	10
Default	1	0.5	10

1 **Table B121: SF6 Circuit Breakers – Anti-Pump Operation Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.55	5.5	10
Default	1	0.5	10

2 **Table B122: SF6 Circuit Breakers – Corrosion**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Normal Wear	1.1	0.5	10
Low Corrosion	1.15	5.5	10
Medium Corrosion	1.25	6.5	10
High Corrosion	1.35	8	10
Default	1	0.5	10

3 *Cable Chambers*

4 **Table B123: Cable Chambers – Walls**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	0.5	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

5 **Table B124: Cable Chambers – Floor**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	0.5	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

6 **Table B125: Cable Chambers – Roof/Slabs**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.3	0.5	10
Substantial Deterioration	1.5	8	10
Default	1	0.5	10

Table B126: Cable Chambers – Lid/Cover

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	0.5	10
Substantial Deterioration	1.4	6.5	10
Default	1	0.5	10

Table B127: Cable Chambers – Cable Racking

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.3	5.5	10
Default	1	0.5	10

Table B128: Cable Chambers – Ducts

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.3	5.5	10
Default	1	0.5	10

Table B129: Cable Chambers – Working Space

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.3	5.5	10
Default	1	0.5	10

Table B130: Cable Chambers – Drain

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.3	0.5	10
Default	1	0.5	10

Table B131: Cable Chambers – Flooding

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.3	0.5	10
Default	1	0.5	10

Table B132: Cable Chambers – Sump Pump

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	0.5	10
Substantial Deterioration	1.3	0.5	10
Default	1	0.5	10

Underground Vaults

Table B133: Underground Vaults – Structure Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	10	0.5
Good	1.1	10	0.5
Slight Deterioration	1.2	10	4
Poor	1.3	10	5.5
Very Poor	1.5	10	8
Default	1	10	0.5

Table B133: Underground Vaults – Hatchway Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	10	0.5
Some Deterioration	1.1	10	0.5
Substantial Deterioration	1.3	10	0.5
Default	1	10	0.5

Table B134: Underground Vaults – Ducts

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	0.8	10	0.5
Some Deterioration	1	10	0.5
Substantial Deterioration	1.1	10	0.5
Default	1	10	0.5

1 **Table B135: Underground Vaults – Flooding**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	10	0.5
Some Deterioration	1.05	10	0.5
Substantial Deterioration	1.2	10	0.5
Default	1	10	0.5

2 (iii) Measured Condition Factors

3 *Padmount Switches*

4 **Table B135: Padmount Transformers – Partial Discharge**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Partial Discharge	1	10	0.5
Low	1.1	10	0.5
Medium	1.3	10	5.5
High (Not Confirmed)	1.5	10	8
Default	1	10	0.5

5 **Table B136: Padmount Transformers – Temperature Readings**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
≤ 55	1	10	0.5
> 55 - ≤ 80	1.1	10	0.5
> 80 - ≤ 95	1.2	10	0.5
> 95 - ≤ 105	1.3	10	0.5
> 105	1.4	10	5.5
Default	1	10	0.5

6 *Network Transformers*

7 **Table B137: Network Transformers – Partial Discharge**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Partial Discharge	1	10	0.5
Low	1.1	10	0.5
Medium	1.3	10	5.5
High (Not Confirmed)	1.5	10	8
Default	1	10	0.5

1 **Table B138: Network Transformers – Temperature Readings**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
≤ 55	1	10	0.5
> 55 - ≤ 80	1.1	10	0.5
> 80 - ≤ 95	1.2	10	0.5
> 95 - ≤ 105	1.3	10	0.5
> 105	1.4	10	5.5
Default	1	10	0.5

2 *Network Protectors*

3 **Table B139: Network Protectors – Tripping Test Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Acceptable	1	10	0.5
Unacceptable	1.3	10	0.5
Default	1	10	0.5

4 **Table B140: Network Protectors – Closing Test Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Acceptable	1	10	0.5
Unacceptable	1.2	10	0.5
Default	1	10	0.5

5 *4kV Oil Circuit Breakers*

6 **Table B141: 4kV Oil Circuit Breakers – Contact Resistance Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.15	0.5	10
Substantial Deterioration	1.25	5.5	10
Default	1	0.5	10

7 **Table B142: 4kV Oil Circuit Breakers – Insulation Resistance Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	8	10
Substantial Deterioration	1.4	8	10
Default	1	0.5	10

1 *KSO Oil Circuit Breakers*

2 **Table B143: KSO Oil Circuit Breakers – Contact Resistance Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.1	4	10
Substantial Deterioration	1.15	5.5	10
Default	1	0.5	10

3 **Table B144: KSO Oil Circuit Breakers – Insulation Resistance Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.25	8	10
Substantial Deterioration	1.3	8	10
Default	1	0.5	10

4 *Vacuum Circuit Breakers*

5 **Table B145: Vacuum Circuit Breakers – Contact Resistance Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	6.5	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

6 **Table B146: Vacuum Circuit Breakers – Insulation Resistance Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	8	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

7 **Table B147: Vacuum Circuit Breakers – Dielectric Withstand Test**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	8	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

1 *Air Magnetic Circuit Breakers*

2 **Table B148: Air Magnetic Circuit Breakers – Contact Resistance Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	4	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

3 **Table B149: Air Magnetic Circuit Breakers – Insulation Resistance Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	0.5	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

4 *Airblast Circuit Breakers*

5 **Table B150: Airblast Circuit Breakers – Contact Resistance Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	0.5	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

6 **Table B151: Airblast Circuit Breakers – Insulation Resistance Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	0.5	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

1 *SF6 Circuit Breakers*

2 **Table B152: SF6 Circuit Breakers – Contact Resistance Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.2	0.5	10
Substantial Deterioration	1.8	6.5	10
Default	1	0.5	10

3 **Table B153: SF6 Circuit Breakers – Insulation Resistance Deficiency**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
As New	1	0.5	10
Some Deterioration	1.5	0.5	10
Substantial Deterioration	1.9	8	10
Default	1	0.5	10

4 *Air-Insulated Padmount Switches*

5 **Table B154: Air-Insulated Padmount Switches – Partial Discharge**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Partial Discharge	1	10	0.5
Low	1.1	10	0.5
Medium	1.3	10	5.5
High (Not Confirmed)	1.5	10	8
Default	1	10	0.5

6 **Table B155: Air-Insulated Padmount Switches – Hot Spots Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Hotspot Detected	1	10	0.5
Low - Class C (< 30°C)	1.1	10	0.5
Medium - Class B (30°C - 50°C)	1.2	10	0.5
High - Class A (> 50°C)	1.3	10	7
Default	1	10	0.5

1 *SF6-Insulated Padmount Switches*

2 **Table B156: SF6-Insulated Padmount Switches – Partial Discharge**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Partial Discharge	1	10	0.5
Low	1.1	10	0.5
Medium	1.3	10	5.5
High (Not Confirmed)	1.5	10	8
Default	1	10	0.5

3 **Table B157: SF6-Insulated Padmount Switches – Hot Spots Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Hotspot Detected	1	10	0.5
Low - Class C (< 30°C)	1.1	10	0.5
Medium - Class B (30°C - 50°C)	1.2	10	0.5
High - Class A (> 50°C)	1.3	10	7
Default	1	10	0.5

4 *Air-Insulated Submersible Switches*

5 **Table B158: Air-Insulated Submersible Switches – Hot Spots Condition**

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Hotspot Detected	1	10	0.5
Low - Class C (< 30°C)	1.1	10	0.5
Medium - Class B (30°C - 50°C)	1.2	10	0.5
High - Class A (> 50°C)	1.3	10	7
Default	1	10	0.5

SF6-Insulated Submersible Switches

Table B159: SF6-Insulated Submersible Switches – Hot Spots Condition

	Condition Input Factor	Condition Input Cap	Condition Input Collar
No Hotspot Detected	1	10	0.5
Low - Class C (< 30°C)	1.1	10	0.5
Medium - Class B (30°C - 50°C)	1.2	10	0.5
High - Class A (> 50°C)	1.3	10	7
Default	1	10	0.5

Wood Poles

Table B160: Wood Poles – Pole % Strength

	Condition Input Factor	Condition Input Cap	Condition Input Collar
≥90%	0.8	10	0.5
80% - 89%	1	10	0.5
67% - 79%	1.05	10	0.5
50% - 66%	1.3	10	5.5
<50%	1.4	10	8
Default	1	10	0.5

Table B161: Wood Poles – Shell Thickness

	Condition Input Factor	Condition Input Cap	Condition Input Collar
Acceptable - ≥ 3 inches	1	10	0.5
Unacceptable - < 3 inches	1.3	10	7
Default	1	10	0.5

(iv) FFA Test Input

Table B162: Station Power Transformers – FFA Test Factor

> FFA Value (ppm)	<= FFA Value (ppm)	FFA Test Factor
-0.01	4	1
4	5	1.1
5	6	1.25
6	7	1.4
7	-	1.6

(v) Oil Test Input

Table B163: Station Power Transformers – Oil Test Factor

Class	Description	Oil Test Factor	Oil Test Collar	Oil Test Cap
Class I	Mineral Oil is in satisfactory condition for continued use.	1	0.5	10
Class II	Mineral Oil does not meet the dielectric breakdown voltage and/or water content requirement.	1.05	0.5	10
Class III	Mineral Oil in poor condition that do not meet the limits.	1.1	3	10

Table B164: Station Power Transformers – Suggested Limits, IEEE Std. C57.106-2015 (Table 3)

Test	Limits
Dielectric breakdown voltage (kV)	> 23
Neutralization number (acidity)(mg KOH/g)	< 20
Water Content mg/kg (ppm)	< 35

(vi) DGA Test Input

Table B165: Station Power Transformers – Hydrogen Condition State Calibration

> Hydrogen (ppm)	<= Hydrogen (ppm)	Hydrogen Condition State
-	100	0
100	700	2
700	1800	4
1800	-	10

Table B166: Station Power Transformers – Methane Condition State Calibration

> Methane (ppm)	<= Methane (ppm)	Methane Condition State
-	120	0
120	400	2
400	1000	4
1000	-	10

Table B167: Station Power Transformers – Acetylene Condition State Calibration

> Acetylene (ppm)	<= Acetylene (ppm)	Acetylene Condition State
-	1	0
1	9	2
9	35	4
35	-	8

Table B168: Station Power Transformers – Ethylene Condition State Calibration

> Ethylene (ppm)	<= Ethylene (ppm)	Ethylene Condition State
-	50	0
50	100	2
100	200	4
200	-	10

Table B169: Station Power Transformers – Ethane Condition State Calibration

> Ethane (ppm)	<= Ethane (ppm)	Hydrogen Condition State
-	65	0
65	100	2
100	150	4
150	-	10

Table B170: Station Power Transformers – DGA Change Category

> % Change	<= % Change	Change Category	DGA Test Factor
-1000	-5	Negative	0.9
-5	5	Neutral	1
5	25	Small	1.1
25	100	Significant	1.2
100	1000	Large	1.4

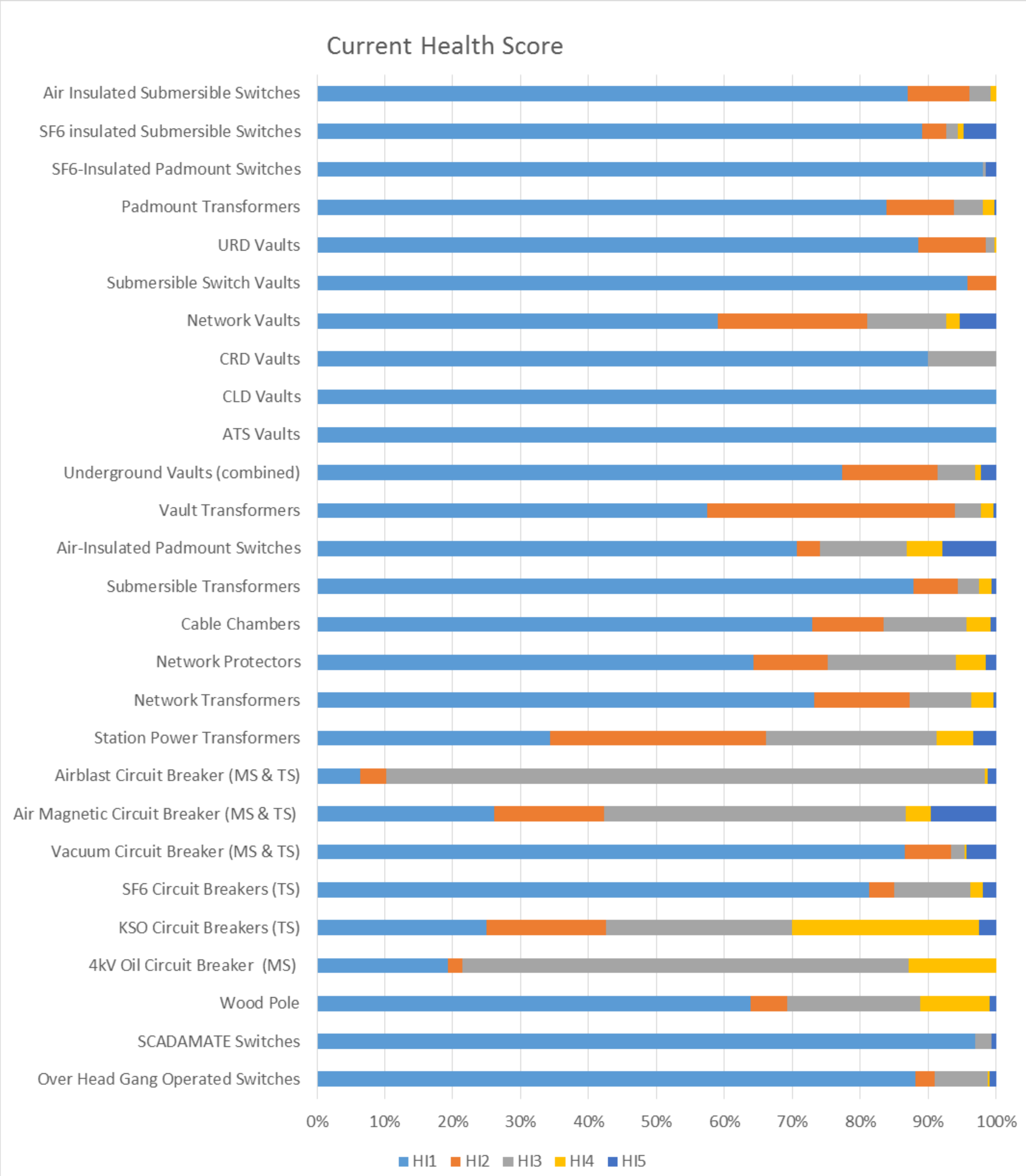
(vii) Reliability Modifiers

Table B170: Network Protectors – Protector Enclosure Type Reliability Modifiers

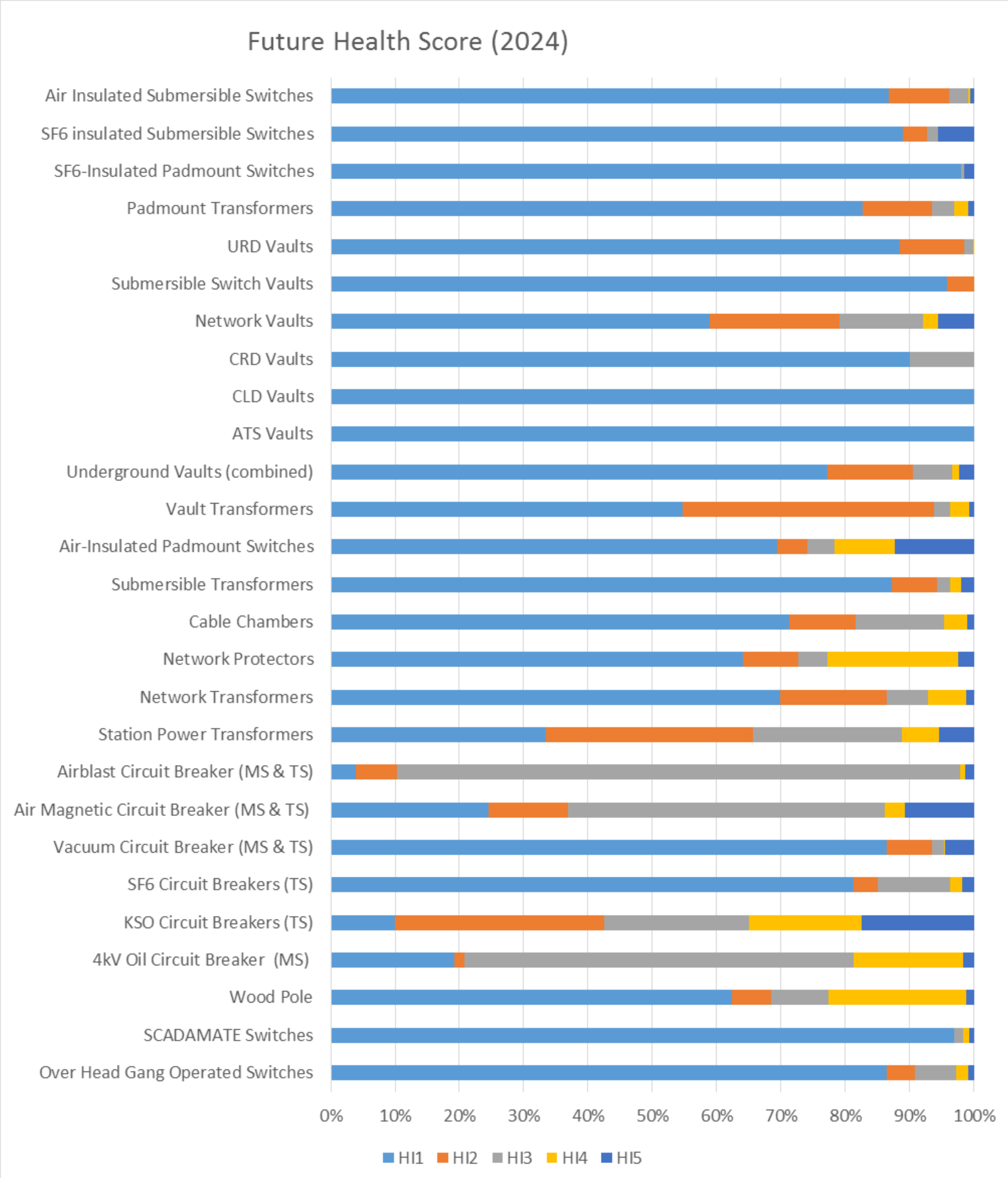
Enclosure Type	Reliability Factor	Reliability Collar
Fibertop	1.4	7
Ventilated	1.25	4
Semi-Dust	1.1	0.5
Submersible	1	0.5

Appendix C – Current and Future Health Score Tables

Table C1: Current Health Score Distribution by Asset Class



1 **Table C2: Future Health Score 2024 Distribution by Asset Class**



Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

June 2015

Image source: Toronto Hydro

Environment

Clean Air Partnership
75 Elizabeth Street
Toronto, Ontario
M5G 1P4

Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

Application of the Public Infrastructure Engineering Vulnerability Assessment Protocol to Electrical Distribution Infrastructure

Final Report - Public

6031-8907

June 2015

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Revisions List

Revision #	Revised by	Date	Description of the revisions
1	AECOM	8 May 2015	Response to Toronto Hydro comments on Preliminary Report
2	AECOM	29 May 2015	Response to Toronto Hydro comments on Final Report

Signatures

Report prepared by: Sophie Potvin-Champagne, Eng. 1 June 2015

Climate Information prepared by: Simon Eng, Risk Sciences International
Heather Auld, Risk Sciences International
Neil Comer, Risk Sciences International

Report verified by: Chee F. Chan, Urban Planner, MUP, B. Sc. 1 June 2015

Executive Summary

The current study aims to evaluate the vulnerability of Toronto Hydro's electrical distribution system within the City of Toronto to a changing climate by employing Engineers Canada's Public Infrastructure Engineering Vulnerability Assessment Protocol (PIEVC Protocol). This study is a high level screening analysis designed to determine where infrastructure vulnerabilities to climate change may be present, to suggest avenues for adapting infrastructure to climate change, and to identify areas of further study.

Electrical Distribution System under Study

Toronto Hydro distributes electricity across the City of Toronto, Canada's largest city and home to approximately 2.8 million people in 2014. Toronto Hydro serves approximately 740,000 customers in the City of Toronto and owns approximately $3 billion dollars in assets, including over 170 transformer stations, approximately 29,000 km of overhead and underground wires, 20,000+ switches, 60,000+ transformers and 176,000+ poles.

The study period of this assessment was 2015 to 2050. A "system" level approach was employed to assess the impacts of climate change on the various parts of the electrical distribution system. This approach divided the distribution system into six major asset categories: stations, feeders, communications systems, civil structures, auxiliary mechanical systems and human resources. Asset categories were assessed based on their general characteristics (e.g. typical, representative or common electrical or mechanical configurations, standards, equipment). For example, this analysis focused on how systems designed to current (post 2000) CSA standards may interact with the climate parameters being considered. Changes to the electrical system considered in this assessment included the planned transition from rear lot to front lot power lines, the partial phase out of 4.16 kV system, some demand and supply projections[1], and replacement of non-submersible equipment. The streetlighting system and systems serving the Toronto Transit Commission (TTC) were not within the scope of this study.

Toronto Hydro documentation, electrical standards and consultations with Toronto Hydro staff (through ongoing communications and two workshops) were all used to help identify and describe asset categories, general characteristics and sensitivities to climate related stresses (climate parameters[2]).

Climate Parameters

20 climate parameters including high temperature, heavy rainfall, snowfall, freezing rain, high winds and lightning were considered in this assessment. Relevant climate parameters and threshold values at which infrastructure performance would be affected were identified through a literature review, consultations with Toronto Hydro staff and analysis of past outage events.

The probability of a climate parameter occurring during the study period was determined using global climate modelling (GCM) data obtained from the Intergovernmental Panel on Climate Change's 5th Assessment Report (IPCC AR5). In many cases, this information was validated or refined through the use of regional climate modelling data, statistical downscaling and climate analogues.

The probability of a climate parameter occurring is expressed both as a study period probability value (i.e. what is the probability of a climate parameter occurring sometime between 2015 – 2050) and an annual probability value centred around the 2030's and 2050's (i.e. what is the annual probability of a climate parameter occurring around

[1] It should be noted that city-wide land use changes (high rises, condo development and population growth) were not included in the analysis, due to the scope of such an undertaking and the complexity of information required. Vulnerabilities were determined based on the assumption that gradual population growth would generally be accommodated by corresponding growth of Toronto Hydro systems under business as usual practices without the added stress of climate change.

[2] A climate parameter is defined by the PIEVC Protocol as a specific set of weather conditions or climate trends deemed to be relevant to the infrastructure under consideration. The parameter may be a single variable, such as mean monthly temperature, or a combination of variables, such as low temperature combined with rainfall.

the 2030's and 2050's). Examining both annual and study period probability was useful for understanding vulnerabilities that may stem from events which could occur on an annual basis (e.g. high temperature) against those which could occur less than annually, but have the potential to cause significant damage to the system sometime during the 35 year study period (e.g. ice storms, high winds, tornadoes). The list of climate parameters considered in this study is shown in table ES-1.

Table ES-1 Climate Parameters and Probability of Occurrence

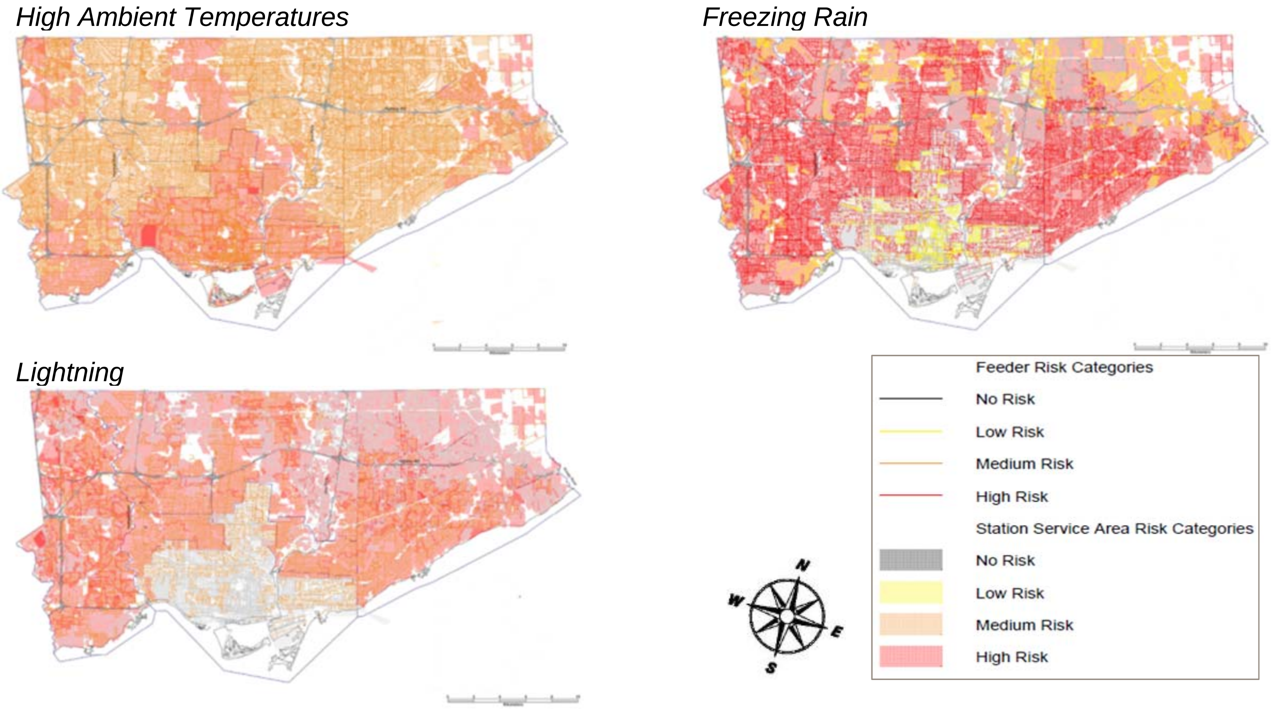
Climate Parameter		Annual Probability (Historical; **Projected 2030's and *2050's***)	Probability of Occurrence Study Period (2015-2050)
Daily Maximum Temperatures	25°C	66 per year; **84 per year**, ***106 per year***	100%
	30°C	16 per year; **26 per year**, ***47 per year***	100%
	35°C	0.75 per year; **3 per year**, ***8 per year***	100%
	40°C	~0.01 per year; **0.3 to 2 days per year**, ***1-7 days per year***	~100%
High Daily Avg. Temperature	30°C	0.07 per year; **N/A**, ***1.2 days per year***	~100%
Heat Wave	3 days max temp over 30°C	0.88 per year; **>1 for both**	100%
High Nighttime Temperatures	Nighttime low ≥23°C	0.70 per year; **7 per year**, ***16 per year***	~100%
Extreme Rainfall	100 mm in <1 day + antecedent	0.04 per year; ***extreme precipitation expected ↑, percentage unknown***	~75%-85%
Ice Storm/Freezing Rain	15 mm (tree branches)	0.11 per year; **>0.13 per year**, ***>0.16 per year***	>99%
	25 mm ≈ 12.5 mm radial	0.06 days per year; **>0.07 per year**, ***>0.09 per year***	>95%
	60 mm ≈ 30 mm radial	Upper bound of estimate: 0.007 events per year; **>0.008 per year**; ***>0.01 per year*** Lower bound of estimate: 0.002 events per year; **> 0.0023 per year**; ***0.003 per year***	High: ~25% Low: ~8%
High Winds	70 km/h+ (tree branches)	21 days per year; **N/A**, ***24 to 26 per year***	100%
	90 km/h	2 days per year; **N/A**, ***>2.5 per year***	100%
	120 km/h	~0.05 days per year; ***likely ↑, but % unknown***	~85% or higher
Tornado	EF1+	1-in-6,000; ***Unknown, no consensus***	~0.6%
	EF2+	1-in-12,000; ***Unknown, no consensus***	~0.3%
Lightning	Flash density per km km^2	1.12 to 2.24 per year per km^2; ***Expected increase, % change unknown***	~50-70%(Lg); ~10-20% (Sm)
Snowfall	Days w/ >10 cm	1.5 days per year; ***Trend decreasing but highly variable***	100%
	Days w/ > 5cm	5 days per year; ***Trend decreasing but highly variable***	100%
Frost		229 frost free days; **249 frost free days**, ***273 frost free days***	100%

Assessing Vulnerability

The vulnerability of the electrical system to climate parameters was determined using a risk based framework (probability of occurrence of a climate parameter coupled with the severity/consequence of the impact on the system). All high risk interactions were deemed as vulnerabilities for Toronto Hydro. Medium risk interactions were evaluated in further detail through an engineering analysis. Those which exhibited sensitivities or consequences similar to high risk interactions were also deemed as vulnerabilities for Toronto Hydro. Finally, interactions rated as low risk were generally judged as not being a significant issue or vulnerability for Toronto Hydro.

A mapping of the risk ratings was also completed as part of this study and represents a useful first approximation of spatial nature of climate change vulnerabilities to the electrical system. The mapping exercise provides additional information on how vulnerabilities stemming from stations can combine with vulnerabilities to feeder systems. In some cases, vulnerabilities stem primarily from station assets, while in other cases, both station and feeder vulnerabilities to weather events contribute to an area of greater vulnerability within the city. This mapping information can be easily combined with other layers of information such as technical hazard information (e.g. flood mapping), critical building and infrastructure locations (e.g. emergency resource centres, hospitals, transportation networks) and social vulnerability indices (e.g. age, income, population density, etc.) from other sources (e.g. TRCA, City of Toronto) to support further mapping studies and in depth analyses.

Figure ES-1 Example Maps Based on Risk Ratings for High Heat, Freezing Rain and Lightning



This study found that distribution system vulnerabilities to a changing climate were divided into five groups based on how climate parameters affect the system.

High Ambient Temperatures – Station and Feeder Assets

High ambient temperatures create problems for the distribution system because of the compounding effect of high demand (e.g. for cooling) and high ambient temperature affecting power transformer capacity and electrical transmission efficiency. Two climate parameters were of most significant concern, daily maximum temperatures exceeding 40°C (excluding humidity) and daily average temperatures exceeding 30°C. For these climate parameters, the analysis found that such extreme temperatures have occurred rarely in the past, but are projected to occur almost semi-annually by the 2030's, and annually by the 2050's. It is anticipated that vulnerability to high heat events will be concentrated in the Former Toronto area, although there are several horseshoe station service areas which would also be vulnerable.

Freezing Rain, Ice Storms, High Wind and Tornadoes – Overhead Station and Feeder Assets

Freezing rain, ice storms, high wind and tornado events can cause immediate structural issues for overhead station and feeder assets, as they have the capacity to exceed the design limits of equipment and their supports. Outages may result from damage to equipment arising from direct forces applied by climate parameters (e.g. wind, ice weight) or by other objects (e.g. tree branches, flying debris). Toronto Hydro has experienced problems related to freezing rain, ice storms (up to 25 mm) and high winds (up to 90 km/h) in the past. These events are projected to continue in the future, but continue to occur on a less than annual, or even decadal frequency. Nonetheless, the damages caused by these kinds of events can be severe, and mostly affect outdoor station and feeder assets, much of which is concentrated in the horseshoe service area.

Extreme Rainfall – Underground Feeder Assets

Extreme rainfall events may potentially flood underground feeder assets. These vulnerabilities are largely concentrated in the Former Toronto and northeastern horseshoe areas. Toronto Hydro is aware of these issues in relation to its assets and has programs to replace non-submersible equipment with submersible type equipment, to relocate equipment where possible. However, due to the large quantity of underground feeder assets across the city, replacement and reinforcement of underground assets will be a gradual and ongoing activity for Toronto Hydro over the study period. As such, some underground feeder assets may remain an area of vulnerability for Toronto Hydro.

Snowfall, Freezing Rain - Corrosion of Civil Structures

The degradation of civil structures (i.e. concrete and steel), which is accelerated by humidity and the presence of de-icing salts, was identified as a potential area of vulnerability to climate change. Corrosion is already an ongoing issue for Toronto Hydro. As such, current assets have a design lifespan which accounts to a great extent for corrosion issues. However, it is not clear from this study whether the climate change stresses will exacerbate this problem. While snowfall days are generally expected to decrease with a warming climate, they will continue to occur annually through to the 2050's. As a result, and in combination with freezing rain events, de-icing salts will also be applied annually through the study horizon, and corrosion will continue to be an ongoing preoccupation. Nonetheless, it should be emphasized that corrosion represents a long-term and on-going vulnerability for Toronto Hydro.

Lightning – Overhead Feeder Assets

Based on workshop feedback and an examination of Toronto Hydro's interruption tracking system's (ITIS) outage data, Toronto Hydro recognizes that lightning impacts are a significant source of outages on the distribution system today. While there have been advances in predicting lightning activity, there was insufficient data available on lightning strike intensity and arrester performance to suggest how future lighting activity may affect the electrical system. For these reasons, this study suggests that lightning strikes will continue to be an area of vulnerability.

Adaptation Options and Areas of Further Study

This study provides high level adaptation options under the themes of engineering actions, management actions, monitoring activities and further study. Generally, for high heat related climate parameters, Toronto Hydro could further investigate avenues to enhance the system's capacity to deal with higher demand under high temperature conditions, especially since extreme heat events are projected to occur on a semi-annual to annual basis by the 2030's and 2050's. On climate events causing structural damage issues (i.e. freezing rain, ice storms, high winds and tornadoes), adaptation options include optimizing emergency response and service restoration, as well as infrastructure hardening and burying infrastructure. While the latter engineering-type solutions are relatively capital intensive, asset renewal cycles provide excellent opportunities to consider these types of upgrades. This study also recommends that Toronto Hydro continue monitoring the occurrences and impacts of major freezing rain, high wind and tornado events on the system, as well as the science of climate change projections. This multi-faceted approach provides Toronto Hydro with greater flexibility in managing vulnerabilities related to these types of extreme climate events.

Other potential options to address identified vulnerabilities include continued monitoring and evaluation of climate change projection science, monitoring impacts of a changing climate on certain asset classes, evaluating the need to strengthen or defend certain infrastructure and equipment from climate parameters, and enhancing emergency response and service restoration practices.

Acknowledgements

This study was completed with support from Natural Resources Canada. It was produced through its Adaptation Platform Electrical Sector Working Group[3]. AECOM would also like to acknowledge Engineers Canada for the technical support, participation and for the use of its Public Infrastructure Engineering Vulnerability Committee (PIEVC) Protocol. The Toronto region's WeatherWise Partnership is also acknowledged for its work on bringing the issue of climate related threats on electrical infrastructure to the forefront, and for its support in bringing about this study. AECOM would like to thank the Clean Air Partnership for the opportunity to undertake this study.

AECOM would also like to acknowledge Toronto Hydro staff for their time and effort in providing information about their system, participating in workshops and meetings, providing insight into the functionality of their system, and reviewing documents and reports. Without their valuable contributions, this study could not have proceeded.

[3] For more information on climate change impacts and adaptation, please visit adaptation.nrcan.gc.ca" (or for French language publications/sites: "adaptation.rncan.gc.ca").

Table of Contents

List of Tables

List of Figures

Appendices

List of Acronyms

CAP	Clean Air Partnership
GCM	Global climate model
GIS	Geographic Information Systems
HONI	Hydro One Networks Inc.
ITIS	Interruption Tracking System
NRCan	Natural Resources Canada
OPG	Ontario Power Generation
PIEVC	Public Infrastructure Engineering Vulnerability Committee
Protocol	The climate change based public infrastructure vulnerability assessment developed by the PIEVC and Engineers Canada
RCM	Regional climate model
RCP	Representative concentration pathway
RSI	Risk Sciences International
THESL	Toronto Hydro-Electric System Limited
TTC	Toronto Transit Commission

1 Study Context

1.1 Introduction and Mandate

In 2012, Engineers Canada partnered with the Clean Air Partnership (CAP) and Toronto Hydro to evaluate the risks of climate change on Toronto Hydro's electrical distribution infrastructure in the City of Toronto. At that time, CAP mandated AECOM and Risk Sciences International (RSI) to undertake a Public Infrastructure Engineering Vulnerability Assessment Protocol (PIEVC Protocol, or the Protocol) [4] based study on select components of Toronto Hydro's electrical distribution system to historical climate. That study, named the Toronto Hydro-Electric System PIEVC Pilot Case (pilot case study), was meant to demonstrate the applicability of the Protocol to electrical systems. The pilot case study was also envisioned as the first of a two-phase project to assess climate change related vulnerabilities to electrical systems. The pilot case study was completed at the end of summer 2012 (AECOM and RSI, 2012).

In summer 2013, CAP and Toronto Hydro elected to pursue the second phase of the climate change assessment with support from Natural Resources Canada's (NRCan) "Enhancing Competitiveness in a Changing Climate" program. NRCan's program is designed to facilitate the development and sharing of knowledge, tools and practices which assist decision-makers in the analysis and implementation of climate change related adaptation measures. CAP, once again mandated AECOM and RSI to carry out the Phase 2 climate change vulnerability assessment (Phase 2 study). The Phase 2 study is the subject of the current report.

1.2 Methodology and Approach

The Phase 2 study again employs the Protocol as the framework for the climate change analysis. The Protocol is composed of five steps:

- Step 1 – Project Definition;
- Step 2 – Data Gathering and Sufficiency;
- Step 3 – Risk Assessment;
- Step 4 – Engineering Analysis;
- Step 5 – Recommendations and Conclusions.

In contrast to the pilot case study, the scope of Phase 2 study was extended to include most of Toronto Hydro owned electrical distribution infrastructure and civil support structures across the City of Toronto. Toronto Hydro's streetlighting system and electrical systems for the Toronto Transit Commission were not within the scope of the present study. Anticipated climate changes and impacts at the 2030 and 2050 time horizons were evaluated. Most of the activities prescribed by the Protocol were completed as part of Phase 2 with the exception of a site visit. The triple-bottom line adaptation solutions development module, an optional undertaking in the PIEVC Protocol, was also not completed as part of Phase 2 of this study[5].

As part of the activities of Phase 2, two workshops were held with Toronto Hydro staff. The first workshop was held on July 3, 2014 in Toronto Hydro's offices in Toronto. At this workshop, an overview of the infrastructure and climate components (Steps 1 and 2 of the Protocol), were presented for discussion and validation with Toronto Hydro staff. On October 10, 2014, a second workshop was held to validate the risk assessment completed by AECOM and RSI (Step 3 of the Protocol).

4 The Protocol is a structured and documented methodology for a screening level assessment of infrastructure vulnerability to a changing climate, and for developing adaptation solutions to identified vulnerabilities. The Protocol, currently in version 10, also allows users to evaluate the vulnerabilities stemming from current climate to the infrastructure as part of the overall assessment.

5 The triple-bottom line adaptation solutions development module guides users in the development and screening of potential solutions to address the impacts of climate change identified in the preceding steps of the Protocol. It was not in the scope of the current study.

The components of the electrical distribution system (e.g. stations, power lines, transformers, switches, supports) under study are highly interdependent, and failures in one part of the system may result in interrelated structural, electrical or functional issues in other portions of the system (e.g. failures in poles may bring down power line and transformers, electrical faults may cause the system to lose protection, control or redundancy). For this reason, the study of electrical systems cannot be examined solely on the basis of its individual pieces or classes or equipment. This study adopts a *systems level approach*[6] to examining the climate change risks to the extensive, complex and interdependent components of Toronto Hydro's electrical distribution system. This approach divides the electrical distribution system into six major systems categories encompassing different individual components and classes of equipment. This generalization of electrical components into major systems categories facilitates an analysis that considers system dependencies and redundancies.

However, by generalizing the system into major systems categories, the granular detail of the system and its components (e.g. site specific characteristics, unique or individual pieces of equipment) may not be adequately captured. Therefore, to complete a reasonable study of the entire electrical distribution system, this study has made assumptions, informed by input from Toronto Hydro staff, about the types and classes of equipment and components typically found within each category. While the loss of granular detail may mask localized issues and vulnerabilities, it does allow this project to provide the first climate change based vulnerability assessment of electrical distribution infrastructure. This can help prioritize future investigations, resources and investment on vulnerable systems and their components in order to enhance the resilience of the electrical system.

1.3 Structure of this Report

This report is divided into seven chapters, including the present one. They are:

- Chapter 1: Study Context;
- Chapter 2: Description of the Infrastructure;
- Chapter 3: Assessment of Climate Changes;
- Chapter 4: Vulnerability Assessment Methodology;
- Chapter 5: Assessment Results;
- Chapter 6: Engineering Analysis; and,
- Chapter 7: Conclusions.

Note that Chapter 3, Assessment of Climate Changes and **Appendix B** and **C**, were authored by Risk Sciences International in consultation with AECOM study authors.

[6] This is in contrast to the component level analysis approach which was employed in the pilot case study.

2 Description of the Infrastructure

2.1 Study Area

The Phase 2 study covers Toronto Hydro's electrical distribution infrastructure and supporting civil infrastructure within the boundaries of the City of Toronto. Toronto Hydro distributes electricity across the City of Toronto, Canada's largest city, the provincial capital of Ontario, and home to approximately 2.8 million people (City of Toronto, 2014). The City of Toronto is bordered by the municipalities of Mississauga to the west (in Peel Region), Vaughan and Markham to the north (in York Region), and Pickering to the east (in Durham Region).

The City of Toronto covers approximately 641 km^2 on the northwestern shore of Lake Ontario (City of Toronto, 2014). The city's topography slopes gradually from the lakeshore, approximately 75 m above sea level to 200 m above sea level at its highest point along its northern border (City of Toronto, 2014). Three river systems cross the City of Toronto and flow into Lake Ontario. The Humber River lies on the west side of the City. The Don River essentially crosses the middle of the City of Toronto and flows into Lake Ontario just east of downtown. Finally, the Rouge River crosses the city's eastern edge. These rivers, their tributaries and creeks total about 307 km of water courses and punctuate the City's generally flat landscape with ravines.

The City lies at the eastern edge of the Carolinian Forest zone. The City contains approximately 10 million trees, approximately 4 million of which are publically owned. Of the latter, there are approximately 600,000 trees along streets and public right of ways, and another 3.5 million trees in parks, ravines and other natural areas of the city (City of Toronto, 2014).

2.1.1 Major Systems Categories Under Study

In 2014, Toronto Hydro's electrical distribution system served approximately 740,000 customers, of which around 658,000 were residential customers. The components of the Toronto Hydro's electrical distribution system are extensive, covering approximately $3 billion dollars in assets, including over 170 transformer stations of different classes, 29,000 km of overhead and underground wires, 20,000+ switches, 60,000+ transformers and 176,000+ poles (Toronto Hydro, 2014b). The present study covers most of Toronto Hydro's electrical distribution infrastructure and civil support structures, with the exclusion of its streetlighting system, and systems serving the Toronto Transit Commission (TTC). The electrical distribution system was divided into six *major systems categories* for the purposes of this study: transmission stations, feeder configurations, system communications, civil structures, mechanical auxiliaries and human resources. Figure 2-1 provides a schematic overview of the systems under study. The *major systems categories* are described hereafter, and hypotheses and generalizations that were made to facilitate the *system level analysis* approach are explained in this chapter. Supporting detail is included in Worksheet 1 of **Appendix H**.

This analysis divides the City of Toronto into two areas: the Former Toronto area and horseshoe area. This distinction is made because most of the legacy equipment is usually found in downtown Toronto and while equipment of newer design can usually be found in the horseshoe area. As such, the *major systems categories* (with the exception of human resources) are also separated between the Former Toronto area (which represents the downtown and inner city) and the horseshoe area (which covers the outlying suburbs). Figure 2-2 shows the division between the Former Toronto area (in green) and the horseshoe area (in blue).

Information about the *major systems categories* was drawn from three principal sources:

- *Overview of the Toronto Hydro Distribution Systems*. Toronto Hydro-Electric System Limited, 2014, Power point 203 p.
- *Overview of the Toronto Area Transmission Systems and Toronto Hydro Distribution Systems*. Toronto Hydro-Electric System Limited, 2014, Power point 121 p.

- System Expansion and Studies Section System Reliability Planning Department. *Toronto Hydro Distribution System Planning Guidelines.* Toronto Hydro-Electric System Limited, 2007, 22 p.

Figure 2-1 Major System Categories Under Study

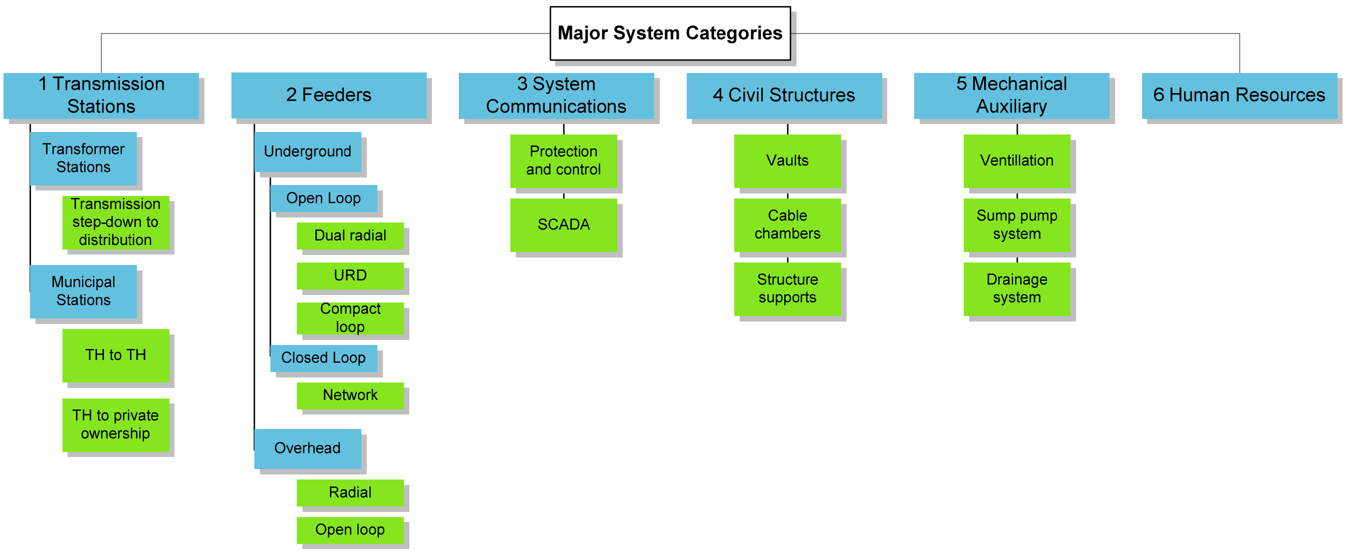
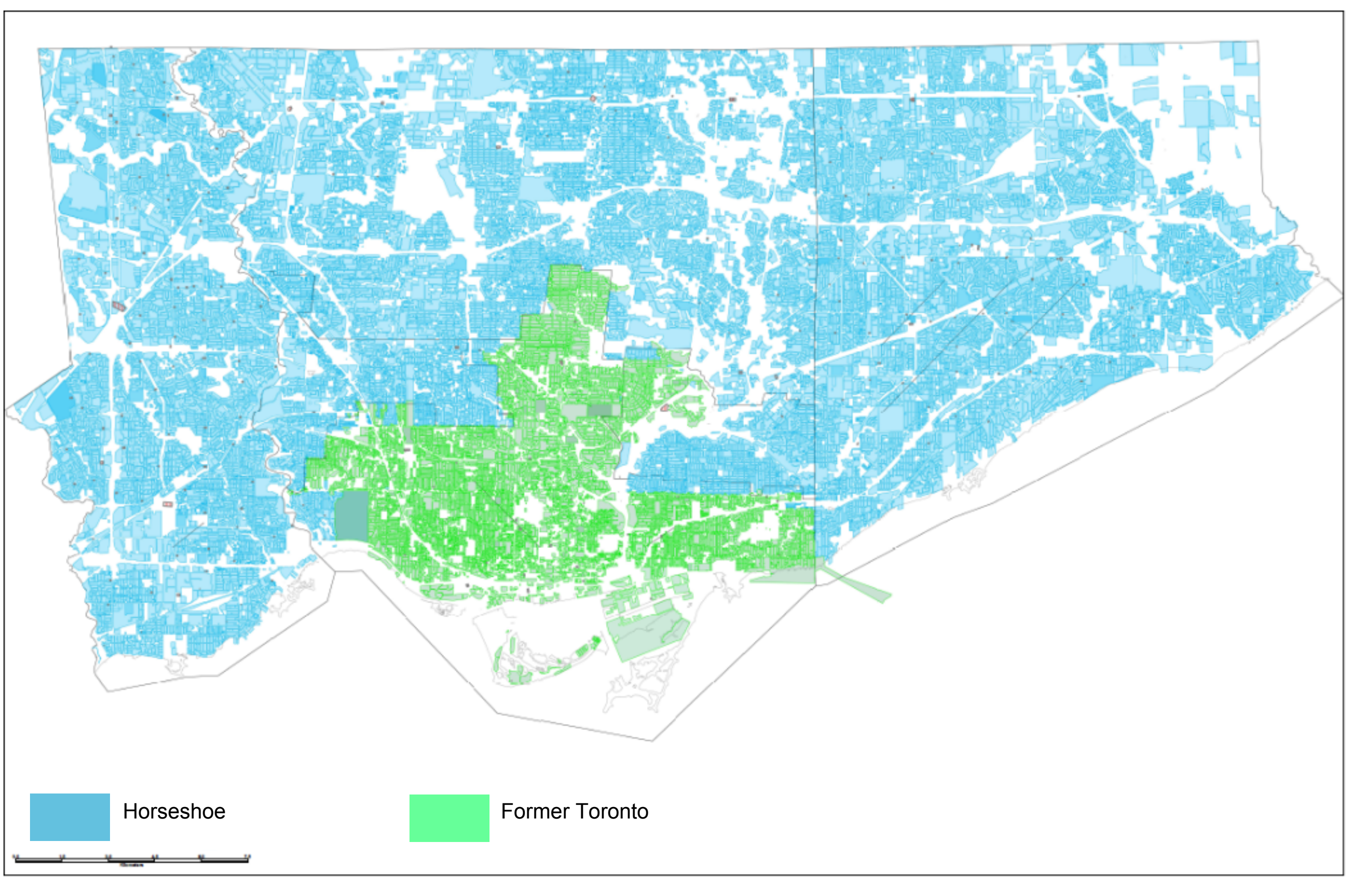


Figure 2-2 City of Toronto Study Area



2.2 General System Overview

The electric power system of the province of Ontario is a large interconnected electrical system of generating, transmission, and distribution infrastructure. Generating stations in Ontario are either privately or publicly owned. From the generation stations, the electricity is transmitted throughout the province over high voltage transmission lines, the majority of which is owned by Hydro One Networks Inc. (HONI). The electricity is then distributed to customers by local distribution companies like Toronto Hydro (Figure 2-3).

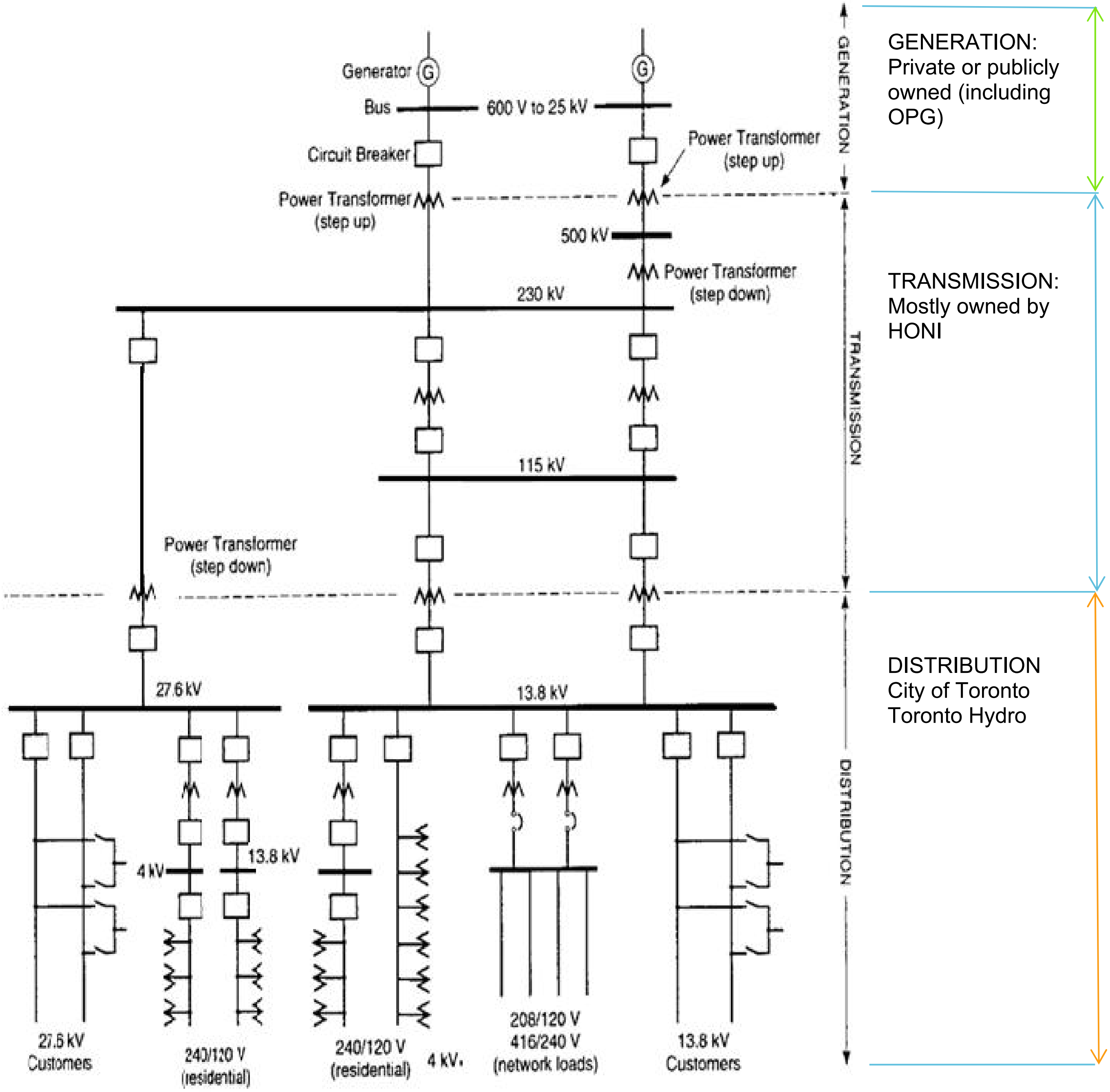
In the case of the City of Toronto, 230 kV and 115 kV transmission lines owned and operated by HONI bring power to the city. The 230 kV transmission lines mostly serve the horseshoe area, while the 115 kV lines serve most of the Former Toronto area. The 115 kV transmission lines are supplied from three major sources: Leaside station (230/115 kV step down) from the east, Manby station (230/115 kV step down) from the west, and by one generating station located within city limits, the Portlands Energy Centre (PEC) owned by Ontario Power Generation (OPG). PEC generates electricity through three natural gas turbine generators.

Presently, there are 35 transmission stations that step down high voltage currents (230 kV and 115 kV) to the distribution system voltages used by Toronto Hydro (i.e. 27.6 kV and 13.8 kV) (Figure 2-4). The equipment within these stations is owned by either Hydro One or Toronto Hydro, with the exception of Cavanagh station, where all equipment is owned by Toronto Hydro. The division of equipment ownership varies by station. However, since transmission stations are critical, first points of entry of electricity into the city's distribution network, this study considers all equipment within the transmission station, since equipment failure within the station, irrespective of ownership, may compromise its function.

From transmission stations, Toronto Hydro distributes electricity via a network of underground and overhead feeder systems at voltages of 27.6 kV and 13.8 kV. A third distribution voltage level of 4.16 kV, a legacy from historical distribution practices, also operates in the city. The 4.16 kV network is supplied by transformation of 27.6 kV or 13.8 kV feeds at Toronto Hydro owned municipal transformer stations. These three distribution voltages will remain in service for the duration of the Phase 2 study period, even though many of the 4.16 kV power lines are gradually being converted to 13.8 kV and 27.6 kV lines.

This electrical distribution infrastructure is connected via communications systems which afford control and protection of electrical equipment from damage or faults. This system is critical to the operation of the electrical system and is part of this study. In addition, this study considers all civil structures that support the electrical equipment and all mechanical equipment inside underground vaults (ventilation, sumps and pumps). A last category includes all human resources operating and managing Toronto Hydro distribution system.

Figure 2-3 Typical Electric Power System



Source: (Toronto Hydro, 2014d)

Figure 2-4 Transmission Stations

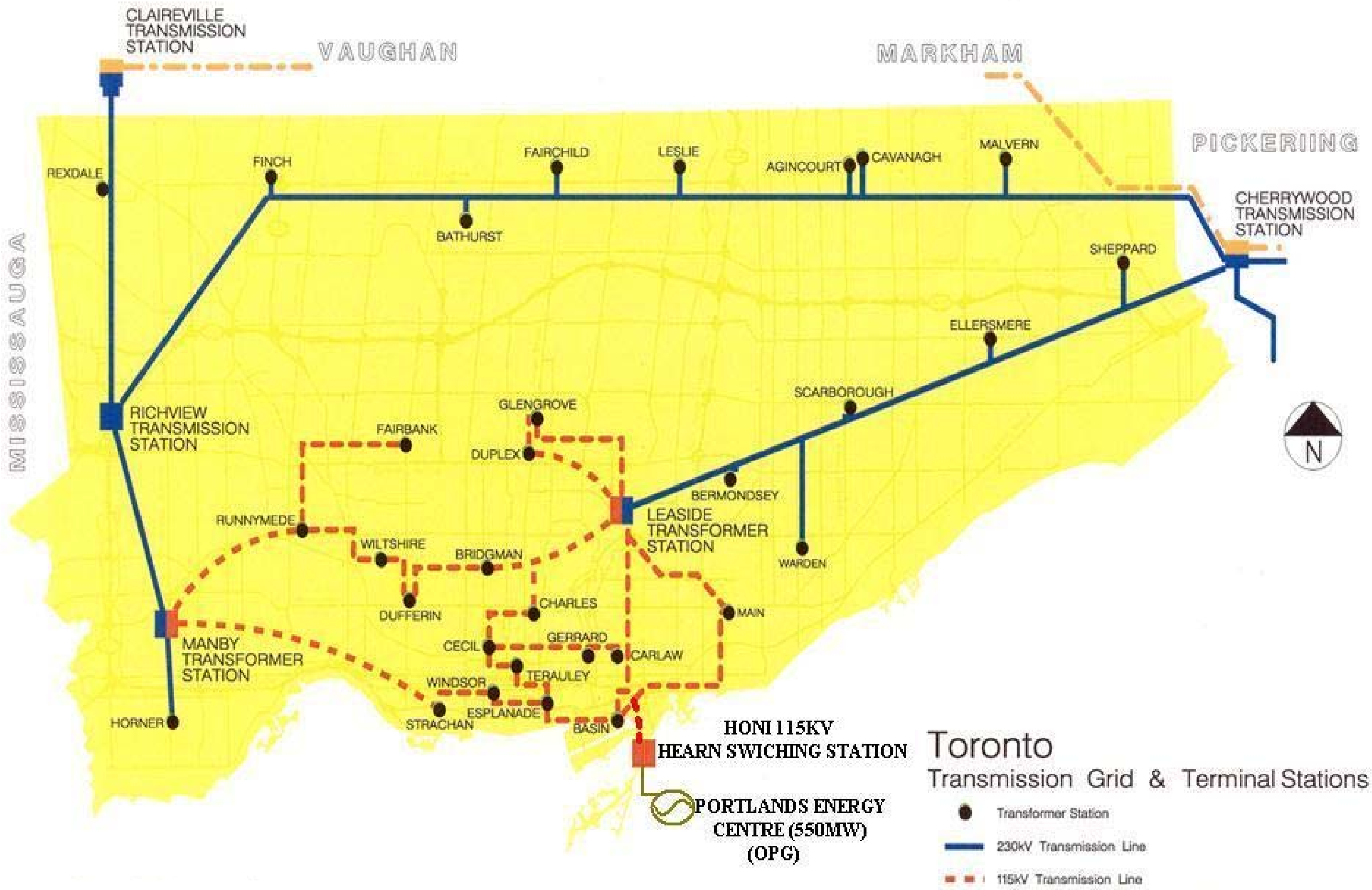


Figure source: (Toronto Hydro, 2014d)

2.3 Substations

2.3.1 Transmission Stations

At the moment, there are 35 transmission stations located in the City of Toronto. Most transmission stations located in the downtown and inner city have primary voltages at 115 kV and step-down to 13.8 kV. In the horseshoe area, the primary voltage is 230 kV and stepped-down to 27.6 kV (most) or 13.8 kV (some). The table below illustrates the list of stations that are divided into the two main service areas, and six sub-service areas[7] (Table 2-1).

[7] Stations have been grouped into these service areas by Toronto Hydro due to:
- Similarity of historical development and presumed potential for future development;
- Theoretical potential for permanently transferring load between neighbouring stations on an operational basis and/or through capital projects;
- Statistical correlation (coefficient of determination, R2) of the overall area growth rate to actual historical peak loads in the area (relative to potential alternative area groupings).

Table 2-1 Transmission Stations and Service Areas[8]

Service Area *(Voltage step down)*	Number of Stations
Former Toronto	
Downtown core *(115 kV/13.8 kV)*	6
Downtown outer *(115/13.8 kV, 230/115 kV, 115/27.6 kV)*	11
Horseshoe	
North Stations *(230/27.6 kV)*	2
East *(230 kV/27.6 kV, 230/115 kV)*	10
Northwest *(230 kV/27.6 kV)*	4
Southwest *(230/27.6 kV, 230/115 kV)*	2

In the Former Toronto area, there are no station ties between station service areas to allow for the transfer of some feeder loads from one station to another. In the horseshoe area, there are existing station ties available to allow the transfer some feeder loads from one station to another.

In the horseshoe area, the transmission stations are considered "outdoor", as all equipment's are exposed to the elements. A control building containing weather sensitive equipment and operators control room is located adjacent to the station. In the Former Toronto area, most stations are configured with equipment located indoors. The entire transmission station is surrounded by fences or walls for public safety.

All stations are essentially based on the Dual Element Spot Network (DESN) design configuration. Typically DESN has two power transformers with 230 kV or 115 kV primary windings, two 27.6 kV or 13.8 kV secondary windings and two buses.

By 2016, the Copeland Station (a gas insulated station) will be brought into service in the Former Toronto area. Gas Insulated Stations occupy less space than air insulated stations of comparable capacity. The gas used for insulation in the Copeland Station is Sulfur Hexafluoride (SF6).

<u>Typical equipment – Transmission Stations</u>

While each of the 35 transmission stations have site specific characteristics, representative and typical equipment found in all stations are:

[8] Station names have been excluded from this version of the report.

- Power transformers
- Lightning arresters
- Current and voltage transformers (instrument transformers)
- Disconnect-switches or interrupters (loadbreak switches)
- Circuit Breakers
- Medium voltage switchgears
- Bus bars
- Transmission station configurations: double bus - double breaker configuration, double bus - single breaker, double bus - double breaker or double bus and one and a half breakers.

A picture of a typical transmission station yard is shown in Figure 2-5.

Figure 2-5 The Station Yard at Cavanagh Transmission Station

Picture source: (Toronto Hydro, 2014a)

Note that this station *major systems category* does not include civil structures or protection and control systems. These other critical infrastructure components which form part of the transmission station are described under separate *major systems categories* below.

2.3.2 Municipal stations

The municipal stations are divided into two sub-categories. First, “Toronto Hydro to Toronto Hydro” municipal stations step down from 27.6 kV to 13.8 kV or to 4.16 kV in the Horseshoe Area, and in the Former Toronto area from 13.8 kV to 4.16 kV. There are also smaller transformer stations located on the sites of Toronto Hydro customers with high load demands. These stations are called “Toronto Hydro to Private ownership” stations in this study.

Toronto Hydro is converting its 4.16 kV voltage level over time to 13.8 kV and 27.6 kV because of age, loss minimization, equipment inventory reduction, and required or projected future load growth (Toronto Hydro, 2007). Toronto Hydro estimated that by 2030, 50% of the 4.16 kV equipment will be converted in the Horseshoe Area and all of it will be phased out in the Former Toronto area. By 2050, Toronto Hydro is expected to have replaced 70% of the 4.16 kV overhead power lines in the Horseshoe (Hypotheses issued in Workshop 1, 2014).

Toronto Hydro to Toronto Hydro

There are around 169 municipal stations (27.6 kV/ 13.8kV or 27.6 kV/13.8 kV / 4.16 kV) within the City of Toronto. Approximately 82 municipal stations are located entirely within a building, and these indoor stations are mostly located in the Former Toronto area. The remaining stations have some or all equipment located outdoors. These stations are classified as outdoor stations for the purposes of this study, and most are located in the horseshoe area. Figure 2-6 shows a picture of a typical outdoor station located in a residential area. For the purpose of this study, it is assumed that all Former Toronto area municipal stations are indoors, while horseshoe stations are outdoors. For those few outdoor stations in the Former Toronto area, their vulnerability will be identical to the outdoor stations in the horseshoe area.

Figure 2-6 Residential Area MS (front and rear views)

Figure source: (Toronto Hydro, 2014a)

Toronto Hydro to Private Ownership

Toronto Hydro to Private Ownership stations supply large loads at low voltages to private customers. The station is located on private property inside a closed room. Most of these stations are owned by Toronto Hydro, although some are owned by the customer.

Typical equipment – Municipal Stations

Typical equipment within municipal stations is similar to transmission stations, but are generally smaller in size because less capacity is required. In general, municipal stations include:

- Oil power transformers (ONAN/ONAF);
- Instrument transformers;
- Disconnect switches;
- Circuit Breakers;
- Cables;
- Fuses;
- Arresters.

2.4 Feeder Systems

Toronto Hydro employs feeder systems, or systems of power lines, transformers, switches and related equipment, to distribute electricity across the City of Toronto. The feeders are either installed on overhead poles (overhead systems) or travel through underground cables (underground systems). Overhead feeder systems can be located on the front side of a property (front lot) or at the back of the property (rear lot). However, rear lot systems will be phased out by the 2030s and are not considered in the scope of this study. They are progressively being replaced by front lot overhead or underground infrastructure, which provides Toronto Hydro more convenient access. In total, Toronto Hydro customers are served by over 900 feeders[9] (Navigant Consulting Ltd. 2011).

Approximately 30 % of Toronto Hydro's distribution network is comprised of 27.6 kV feeders from 3 - 4 km (considered ''short'' lines) to 5 - 6 km (considered ''long'' lines) in length. These systems are mostly located in the horseshoe area. 70 % of Toronto Hydro's distribution feeders operate at 13.8kV, and vary in length between 2 – 3 km (short) to 3 - 4 km (long) (Navigant Consulting Ltd., 2011). The 13.8 kV systems serve both the downtown and horseshoe areas. A very small percentage of feeders still operate at 4.16 kV.

2.4.1 Electrical Configurations

The electrical configuration of a feeder determines the way electricity is delivered to customers. It is indicative of the feeder's ability to provide electrical service in the event of equipment damage and electrical faults. There are many different electrical configurations of feeders, and they include radial, dual radial, open loop and closed loop systems. Some of these systems may also be nested within one another (e.g. an open loop system with downstream radial feeders). Toronto Hydro's main underground and overhead feeders are arranged in an open loop type configuration, although there are also dual radial and radial feeder systems, some of which may be nested within the open loop configuration. Only one feeder type, the 13.8 kV network, is arranged in a closed loop type configuration. The various electrical configurations considered in this study are:

- Underground dual radial and underground residential distribution (URD) feeders;
- Underground closed loop network feeders;
- Overhead open loop and radial feeders.

In the open loop system, the feeder line runs out of the station through two separate feeder arms that eventually reconnect outside the station to form a loop. A load interrupting switch (tie switch) is located at the reconnection point and is normally kept open between the two feeder arms. If one feeder arm goes out, the load can be fed by the other feeder arm by closing the tie switch. In open loop systems under single contingency condition[10], the customer typically experiences an interruption when the feeder is switched from one feeder arm to the other.

In radial systems, the customer is supplied by only one feeder. It is the least expensive design but also offers the least flexibility in electrical service restoration in the event of a fault, as there is no other feeder that can supply electricity until the line is repaired. Radial feeder segments may be nested within open loop systems.

Dual radial systems are similar in design to radial feeders except that each customer is connected to two parallel radial feeders. The load is supplied by one of the radial feeders, as the other radial feeder remains on standby. In the case of a fault, the load is transferred from one feeder to the other by manipulating interrupter switches tying the two radial feeders together. Large commercial and industrial customers, as well as Toronto Hydro municipal stations and several older Toronto Transit Commission (TTC) stations are typically served by dual radial systems. A compact loop system is similar in configuration to a dual radial system, but is employed where space is more limited (e.g. in existing vaults).

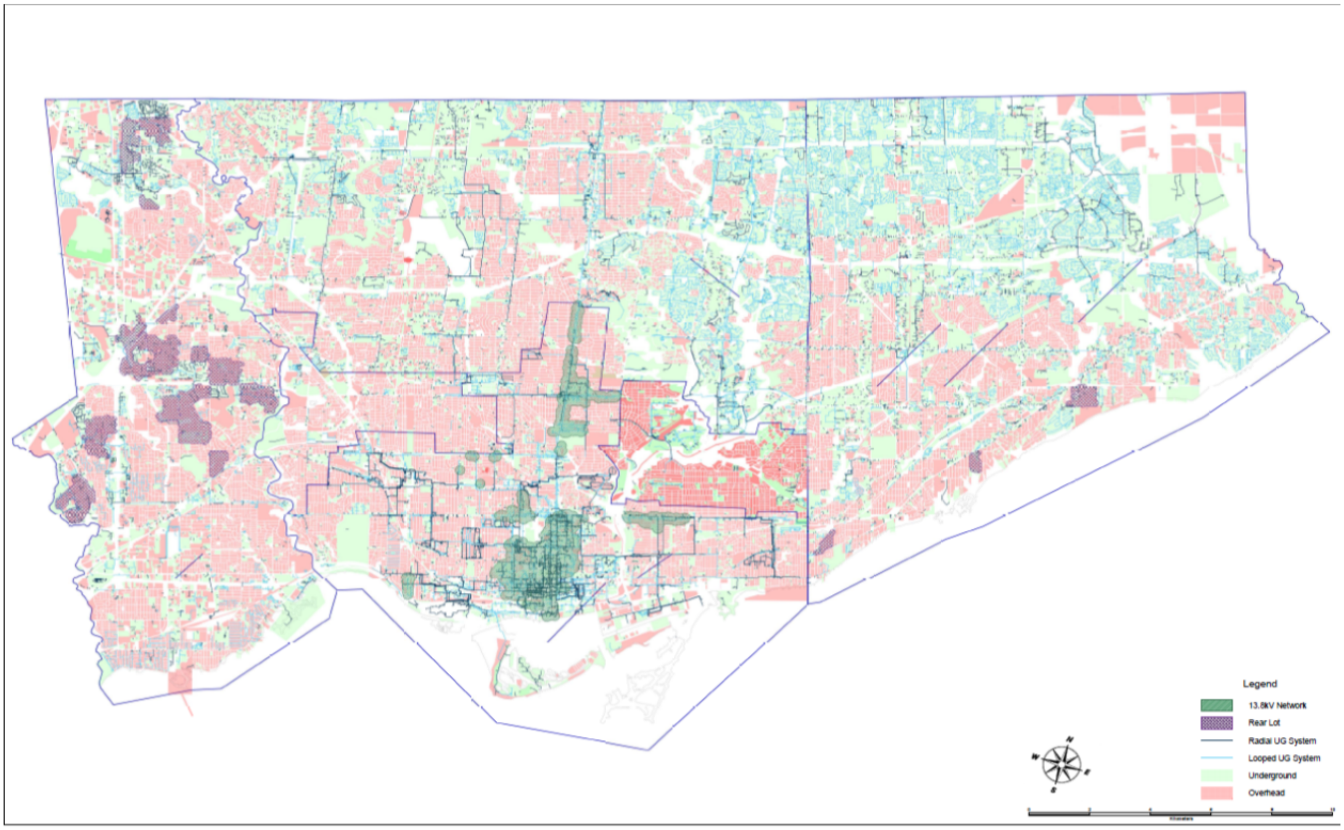
In closed loop systems, customers are supplied by multiple feeders, and are fed via several redundant transformers and network protectors. If one feeder goes out, the customer can be supplied by another feeder. Closed loop systems are advantageous because under single contingency conditions, customers experience no power interruptions (Toronto Hydro, 2007). Only Toronto Hydro's 13.8 kV network system is a closed loop system.

[9] This total may vary depending on how feeder branches and sub-branches are counted.

[10] Single contingency condition or N-1 represents the condition where all electrical equipment is in service except one element. For example, if a substation has two power transformers, but one of them is out of service, the condition is called "N-1". The condition "N-1" generally occurs after a major disturbance causes equipment to trip and go-offline.

Figure 2-7**Error! Reference source not found.** shows the distribution of feeder types across the city. The 13.8 kV network, represented in dark green, is mostly concentrated in downtown Toronto (downtown core and the Yonge Street and Bloor Street corridors), while the other feeder types can be found across the city.

Figure 2-7 Location of Feeders, by Type



Source: Toronto Hydro

Typical equipment

For all underground feeders

The distribution transformer station of underground feeder systems can be classified according to one of three types:

- Vault type: The vault transformer can be small and located just below ground for single phase clients, or large and deeper underground for clients requiring larger, three-phase power supplies. Some vault type transformers can be located above ground inside a building. The equipment located in vault type enclosures cannot operate if the vault is flooded.
- Submersible type: They are designed similarly to the vault type transformer stations but the equipment is designed to operate when submersed. For example, submersible transformers are capable of continuous unattended operation while completely submerged under a head of 3 m of water over the top of the tank (IEEE Std C57.12.24, 2009, p. 3). They are currently the preferred design due to their submersibility.
- Padmount type: The padmount transformer is located on ground level in a metal-clad enclosure.

Underground feeder equipment typically consists of the following:

- Cables: The cables used in underground systems are generally insulated with cross-linked polyethylene (XLPE) or a paper insulated lead cover (PILC). The PILC cables also contain oil
- Pilot wire: For large and sensitive customers

- Fault circuit indicators
- Power transformers modules:
  - Load-break switch modules: Metal enclosed, air insulated, Vacuum or SF6 arc extinction, motorized or manual;
  - Fuse modules: Metal enclosed, air insulated, electronic fuses or SF6 power fuses or current limiting fused;
  - Power transformer : Oil type (most), dry type (in above grade vaults) or some used FR3 fluid (environmental friendly);
  - Elbows: cable connections to power transformers.
- Specifically for the network system, typical equipment consists of the following:Primary feeders;
- Network Units;
  - Primary Switch – Embedded in power transformer;
  - N/W Transformer: dry type;
  - N/W Protector: Breaker, back-up fuse, relays, current transformers, cable limiter.
- LV secondary network grid or spot networks;
- Except for the old network protectors, all network unit equipment are submersible.

For overhead, open loop and radial feeders:

- Poles: See civil categories below;
- Distribution transformers : ONAN (Oil Natural Air Natural) system;
- Gang-operated switches, single-phase switches or SCADA switches;
- Load interrupting switches;
- Fuse disconnecting switches;
- Conductors: “tree proof” protected aluminium (AL) conductors, steel reinforced aluminium conductors (ACSR), aluminium conductors (no tree proof protection), and copper (CU, legacy);
- Voltage Regulators;
- Circuit-breakers with reclosers;
- Capacitors;
- Insulators: made from porcelain (approximately half of all installed insulators) and polymer material (porcelain insulators are being progressively replaced by polymer insulators).

2.5 Communications Systems

The communications systems support the control and protection of electrical equipment. They are divided between protection and control systems, and the SCADA system.

For power lines, the distribution switch automation is generally limited to the 27.6 kV systems (Toronto Hydro, 2007).

Protection and control systems

The protection and control systems are located inside control buildings. Except for batteries, they are located in a temperature controlled room. Batteries at some stations in the Former Toronto area are currently located in the basement of buildings. However, Toronto Hydro expects to relocate these battery assets above grade by the 2030’s in order to help reduce flooding threats.

Typical electrical equipment

- Relays:
- Fuse, Load-break Switch, Circuit Breaker;
- Batteries;
- Auxiliary systems: cranes, fire alarm systems, air compressors, etc.

SCADA system

The supervisory control and data acquisition (SCADA) system is an automated system to remotely control equipment and gather operating information about electrical equipment.

Typical electrical equipment

- SCADA Switch;
- Battery;
- The remote terminal unit (RTU);
- Fault Detector;
- Fiber optic conductor;
- Motorized cell interrupter.

2.6 Civil Structures

The civil structures house or provide structural support for all electrical equipment. They are found in transmission and municipal stations, and all underground and overhead feeder systems.

As a general rule of thumb, civil structures are generally older in the Former Toronto than in the horseshoe area. Older structures (before 1970) may be more susceptible to climate impacts due to their degradation (wood rotting, corrosion of steel) and lack of reinforcement in concrete and design loads.

Typical equipment

For transmission and municipal stations:

- Gantry Towers;
- Exit lines;
- Equipment supports;
- Building: for indoor stations.

For underground feeders and transformer stations:

- Reinforced concrete cable chambers;
- Concrete vaults;
- Underground cable ducts.

For overhead feeders:

- In 2014, there were approximately 176,000 poles in Toronto Hydro's electrical distribution system. The types of poles by construction material are approximately distributed as follows :
    - Concrete : 36%;
    - Aluminum: 2%;
    - Steel: 4%;
    - Cedar Poles : 58%;
    - Fiber glass: Negligible.
    - Iron: Negligible.
- Conductors and hardware (e.g. supports, bolts, etc.);
- Concrete footings (for steel, aluminium, concrete and some wood poles).

2.7 Auxiliary mechanical

Ventilation

All vaults have passive ventilation i.e. natural ventilation through slot openings in cover grates.

Drainage system

Toronto Hydro drainage systems can generally be divided according to the two types of vaults in which they are found:

- Small, shallow single phase sub vaults: do not contain pumps. These vaults' drains are connected to the city's sewer or storm sewer system and drain naturally. These vaults are also being fitted with automatic Petro plugs which stop drainage when oil is detected in the flow (equipment or other pollutant source) in order to prevent oil leaks into the sewer.
- Big deep vaults for Network, URD feeders: most of these kinds of vaults are equipped with mechanical pumps as they are located at a significant depth below grade and often below city sewers. Drains are installed in the walls of the vault and pumps are used to force water into the city's sewer systems. Approximately 10 % of network, URD vaults have drains without pumps (i.e. gravity driven natural drainage).

Sump pump

In 2014, approximately 1600 vaults out of 14,937 vaults had sump pumps (11%) (Toronto Hydro, 2014e). Toronto Hydro estimates that by the 2030's, these sumps will have oil sensing traps that will close if oil (equipment or other pollutant source) is detected.

2.8 Human Resources

Toronto Hydro has approximately 1,500 employees comprised of certified tradespeople, engineers and management professionals (Toronto Hydro, 2012). Employees who are involved in the operation of the electrical distribution system include supervisors and field crews for overhead, underground and network systems, control room staff, call centre workers and dispatchers. Toronto Hydro staff also includes the management team, engineers, asset management specialists and electrical system designers.

Weather can generally affect human resources in two ways. Adverse weather events can affect travel conditions on the journey to and from work for all employees. Furthermore, adverse weather events can affect the working conditions for field crews and field supervisors who need to access, operate or work on equipment across the city. Toronto Hydro strives to ensure a safe working environment for its employees, and has occupational health and safety policies and procedures in place that conform with the international occupational health and safety management system specification OHSAS 18001. These policies and procedures are complemented by the professional judgement of its workers as to whether conditions are safe enough to access outdoor equipment.

2.9 Time Horizon

The evaluation was carried out for the study period (2015 to 2050), but with specific focus on the possible state of the electrical system at the 2030's and 2050's time horizons. For example, this study considered changes to infrastructure systems based on current practices, trends and policy directions (e.g. transition from rear lot to front lot power lines, the partial phase out of 4.16 kV system, some demand and supply projections[11], replacement of

[11] It should be noted that city-wide land use changes (high rises, condo development and population growth) were not included in the analysis, due to the scope of such an undertaking and the complexity of information required. However, system vulnerability was judged based on climate change stresses, as it was assumed that gradual population growth would be accommodated by corresponding growth of Toronto Hydro systems under business as usual practices without the added stress of climate change.

non-submersible equipment). Toronto Hydro documentation, electrical standards and consultations with Toronto Hydro staff were all used to help identify and describe the potential changes to assets at the 2030's and 2050's time horizon. The probability of a climate parameter occurring during the study period and on an annual basis for the 2030's and 2050's was also determined (see next chapter for further details).

2.10 Other Potential Changes that May Affect Infrastructure

2.10.1 Dependencies on Hydro One Infrastructure

Toronto Hydro is part of an interdependent electrical system that is reliant on infrastructure facilities that generate electricity, transmission systems that transport electricity over long distance, and transformer stations that convert voltages for transport and use. The electrical generation and transmission supply infrastructure on which Toronto Hydro relies upon can also be vulnerable to the impacts of a changing climate, and are owned by other electrical companies and organizations in Ontario. Therefore, it is important to note that the vulnerability of Toronto Hydro is therefore also tied to the vulnerability of these supply side infrastructure.

It should also be noted that in the event of a power outage, certain facilities and dependent infrastructure can be supplied by temporary, backup power generators (such as diesel or natural gas generators). In some cases, homeowners may be equipped with photo-voltaic cells that may be able to provide some power in the event of an outage. However, these forms of dispersed generation are specific to facilities and individuals, and not sufficient to meet the demands of larger portions of the population. Dispersed generation does not currently provide sufficient capacity to alleviate Toronto Hydro of its dependence on the large scale electrical generation and transmission supply infrastructure.

Most of the 230 kV, 115 kV and 27.6 kV station equipment that tie Hydro One transmission infrastructure to Toronto Hydro are owned by Hydro One, except for the 27.6 kV breakers at the transmission stations supplying the former North York area and the Cavanagh transmission station, which is totally owned by Toronto Hydro. In general, Toronto Hydro owns the 13.8 kV switchgear equipment. Toronto Hydro and Hydro One share a common Transmission Connection Agreement (Toronto Hydro, 2007).

2.10.2 Load Projections

Electrical load or demand is a significant factor in the operation of transmission stations. Demand is influenced by a variety of factors, including population size, types of uses (e.g. residential, commercial, industrial, institutional, infrastructure), time of day (e.g. peak, off-peak, night time), as well as daily temperature (e.g. heating, cooling).

For the present study, the projections of electrical load on each of the main transmission stations serving the City of Toronto were completed, and are shown in the next table. The methodology used by Toronto Hydro to calculate the projected load for the 2030's and 2050's is described in **Appendix F**. Major future load demand, added transmission station added capacity (i.e. growth), and proposed load transfers[12] were considered by Toronto Hydro.

[12] Load transfer represents the capability to discharge some load from one station to another transmission station. In case of an outage or a very high demand, the loss of supply, or requirement for additional electricity can be provided by another location. Some transmission stations have higher transfer capabilities than others due to higher installed capacity and/or lower demand. However, this capability changes with time: the increasing demand can lessen this flexibility, while investments in new additional capacity can increase the station capability.

Table 2-2 Load Projections by Transmission Station

Service Area *(Voltage step down)*	Number of Stations	Projected load (2030's)[13]	Projected load (2050's)
Former Toronto			
Downtown core *(115 kV/13.8 kV)*	6	86-95%	>95%
Downtown outer *(115/13.8 kV, 230/115 kV,115/27.6 kV)*	2	70-85%	>95%
	6	86-95%	
	3	>95%	
Horseshoe			
North Stations *(230/27.6 kV)*	1	86-95%	>100%
	1		86-95%
East *(230 kV/27.6 kV, 230/115 kV)*	1	<70%	70-85%
	2	<70%	86-95%
	3	70-85%	86-95%
	2	86-95%	86-95%
	1	86-95%	>100%
	1	>100%	>100%
Northwest *(230 kV/27.6 kV)*	2	70-85%	>100%
	1	86-95%	86-95%
	1	<70%	86-95%
Southwest *(230/27.6 kV,230/115 kV)*	2	86-95%	>100%

2.11 Data Sufficiency

The general characteristics of the systems under review were adequate for the purpose of this exercise, although it should be noted that no site visit was conducted in the project. Chapter 7 contains recommendations about further work that can be used to enhance the analysis of electrical system performance and sensitivities to climate related stresses.

[13] Note that Toronto Hydro considers 95 % as the max station load capacity in former Toronto area. This is because there are no station ties between station service areas to allow for the transfer of some feeder loads from one station to another. When a former Toronto area station achieves 95% of its capacity, it signals to Toronto Hydro that a station load relief project is required. In the horseshoe area, station max capacity is considered to be 100% max load capacity, as there are existing station ties available to allow the transfer of feeder loads from one station to another.

3 Assessment of Climate Changes

This chapter describes how the climate data used in this study was developed. This work involved three activities, the identification of climate parameters, the estimation of the historical and future probability of occurrence of climate parameters, and the conversion of probabilities into PIEVC scoring to support the risk assessment. The results of this work are summarized in a table at the end of this chapter (Table 3-2). **Appendix B** and **C** support this chapter, providing additional background information on the methods, information sources and assumptions. The climate work was principally conducted by Risk Sciences International in collaboration with AECOM.

3.1 Climate Data Development Methodology

The development of climate data to support this study involved three main activities.

- First, climate parameters (e.g. temperature, precipitation, wind) and threshold values at which infrastructure performance would be affected were identified (i.e. climate parameters);
- Next, the probability of occurrence of each climate parameter was estimated for future climates; and,
- Finally, the probability information of climate parameters was converted into the PIEVC seven point scoring scale to support the risk assessment.

3.1.1 Identification of Climate Parameters

The identification of relevant climate parameters and infrastructure impact thresholds was an iterative process involving a combination of three methods:

- Literature review of design loads in codes, standards and published literature;
- Practitioner consultation, including targeted interviews, email communications, and workshops; and,
- Forensic analyses of either system specific case studies or relevant cases in the published and grey literature.

While these methods were employed during Phase I, they were expanded significantly and updated for Phase 2. The list of climate parameters from Phase 1 of this study was revisited through practitioner consultations (i.e. workshops), and a more thorough forensic analysis process was conducted using newly available impacts data provided by Toronto Hydro. Literature, including the Institute of Electrical and Electronics Engineers (IEEE) and CSA standards, was reviewed by both RSI and AECOM research team members, yielding more specific design thresholds and criteria. Further information about these techniques can be found in **Appendix B.**

3.1.2 Estimating the Probability of Occurrence of Climate Parameters

To estimate the probability of occurrence of climate parameters over the study period, their probability of occurrence was first established for historical climates. Future conditions cannot be well understood until current and historical climate conditions are quantified, particularly with regards to already existing vulnerabilities and thresholds present within the distribution system. This historical information was combined with climate projections from an ensemble of global climate models through the application of the “Delta-method” (see description on next page) to obtain estimates of the probability of occurrence for climate parameters. Additional complementary estimation techniques (i.e. regional climate models, statistical downscaling, climate analogues) were also employed to evaluate several complex climate events (e.g. freezing rain, ice storms, high intensity rainfall, lightning, tornadoes), as well as to validate or refine the results obtained from the “Delta-method” approach. These tasks are summarized in the following section while more details can be found in **Appendix B**.

Establishing Historical Climate Baseline

The probability of occurrence of climate parameters under historical climate conditions was established in Phase I of this study. Phase 2 reviewed and further refined them in order to serve as a baseline for climate change projections.

Historical climate conditions were established based on Environment Canada's climate station network, the most reliable and highest quality long-term climate record in Canada. While there are numerous climate stations in and around the City of Toronto, detailed hourly weather data are usually only available from airport locations. Thus, the majority of historical climate information used in this analysis is based on records from Pearson International Airport, with further contributions from Buttonville and Toronto Island Airports. Toronto is also the location of the climate station with the longest period of record in Canada, located at its City Centre location, a separate site which provided further perspective on longer term historical climate.

In the case of extreme, very localized, or complex climate events (e.g. tornadoes, freezing rain, ice storms, lightning storms), authors employed alternative methods (e.g. using averaging periods greater than 30 years) or consulted alternative data sets (e.g. the historical tornado database) to establish a historical baseline because this information was not directly available from weather station data.

Future Projections

The climate projection data which serves as a basis for this study was sourced principally from global climate models (GCMs). The latest International Panel on Climate Change (IPCC) 5th Assessment Report (AR5) provided results from 40 GCMs, produced and operated by modeling centres from around the globe. These models provide many of the basic parameters used in developing projections, as well as providing the "boundary conditions" for more detailed assessments, such as downscaling studies. The availability of multiple models also allows for the use of climate model "ensembles," which use multiple models for the development of projections, rather than employing the results of a single model which may contain biases affecting the accuracy of results. The use of ensembles is considered by the IPCC as a best practice for climate analyses, and therefore has been the dominant method used for climate projections in Phase 2.

GCMs require "emissions scenarios" as inputs for the calculation of climate projections. The latest IPCC AR5 has introduced a new method of describing future changes in emissions. Representative Concentration Pathways, or RCPs, describe explicitly the expected increase in energy generated by increases in greenhouse gases. The most pessimistic emissions scenario, RCP 8.5, indicates an increase of 8.5 watts per square meter of additional energy under future climate conditions. It is referred to as the "business as usual" emissions scenario, provides the best fit based on historical trends in global emissions, and was the scenario used for Phase 2. Further details on IPCC findings, GCMs, RCPs, and other aspects of climate change projections, can be found in **Appendix B.**

Applying the "Delta-Method"

Individual GCMs contain inherent biases when attempting to recreate historical climate, for example being either too cool or warm compared to historical averages. To compensate for this effect, the "Delta-method" was employed. First, GCMs were evaluated to determine changes from their own respective baselines. This difference between model baseline and projected conditions is then applied to the observed historical climate baseline. For example, if the GCM ensemble indicated an average increase of 2 degrees between the baseline period and the 2050's, and a given station shows an average annual temperature of 3°C, then the projected annual average temperature for that location for the 2050's becomes 5°C. This represents the "delta", or the change in climate parameter based on the difference projected by the GCM ensemble applied to historical baseline data.

Treatment of Complex Climate Events

To validate the results obtained from the GCM – "Delta-Method" for some of the climate parameters, three other complementary estimation techniques were also used, regional climate modeling, statistical downscaling techniques and climate analogues. Furthermore, some complex climate events tend to occur on much smaller spatial and temporal scales than are covered by GCMs (e.g. tornadoes, freezing rain, ice storms, lightning). Use of these three complementary estimation techniques was necessary to develop projections for these kinds of climate parameters.

It should be noted, however, that even with the availability of specialized methods, there remain highly localized atmospheric events which cannot be projected with confidence, and the effects of climate change on these types of events are still being researched by the climate research community. See **Appendix B** for further discussion of developing projections for complex climate events.

Estimating the Probability of Occurrence of Climate parameters

The methodology used for determining climate parameter probabilities for Phase 2 was somewhat modified from standard PIEVC Protocol based studies. The Protocol (Engineers Canada, 2012) indicates that the probability of a climate parameter occurring should be based on the probability of occurrence during the *full* time period of the study, which is typically the life cycle and long-term planning considerations of the infrastructure under study. For Phase 2, a period of 35 years between 2015 and 2050 was chosen. However, in recognition that response to these hazards can include both asset hardening/replacement cycles (long-term measures) as well as maintenance and management considerations (short term measures), a second set of probabilities based on annual occurrence was also determined. Examining both annual and study period probabilities was useful for understanding vulnerabilities based on climate parameters that would occur on an annual basis (e.g. high temperature) against those which would occur less than annually, but with the potential to cause significant impacts sometime during the 35 year study period (e.g. ice storms, high winds, tornadoes).

Annual probabilities are expressed as the number of occurrences per year for historical and (where available) projected estimates for the 2030's and 2050's, or more specifically for 30 year periods centred on those future decades. The so-called "study period" or "lifecycle" probability of occurrence is then expressed as a percentage (i.e. given those annual frequencies, what is the overall probability that an event will occur during the *entire 35 year time horizon*?).

The probability of occurrence of a climate parameter considered in this project is, in most cases, representative of a "point" probability (i.e. historical probability values based on measurements at a single location). However, the lightning and tornado climate parameters were also evaluated using different "target" sizes to illustrate the effects of changing this perspective, as well as to better correspond with field conditions and associated response. More detailed information about how the probabilities of individual climate parameters were determined can be found in **Appendix B**. The results of this work are listed in Table 3-2 at the end of this chapter.

3.1.3 Assigning a PIEVC Score to Climate parameter Probabilities

The probability of occurrence for climate parameters both annual and during the study period were converted into PIEVC probability scores (i.e. 0-7) for the risk assessment, following the quantitative "Method B" approach indicated in the Protocol (Engineers Canada, 2012) (see Table 3-1). For example, the annual probability of occurrence of high temperatures above 40°C was estimated to occur approximately 0.01 times per year in the historical period (last 100 years), or 1 % probability of occurring each year (PIEVC score 1). Similarly the annual probability for this parameter was 0.3 to 2 times per year for the 2030s, which signifies a 30 % to >100 % probability of occurring each year (PIEVC scores 4 to 7 respectively). This climate parameter is estimated to occur between 1 to 7 days per year by the 2050s, such the annual probability of occurrence is >100% (PIEVC score 7).

Table 3-1 PIEVC Version 10 Probability Scores based on Method B

Score	Probability	
0	< 0.1 %	< 1 in 1,000
1	1 %	1 in 100
2	5 %	1 in 20
3	10 %	1 in 10
4	20 %	1 in 5
5	40 %	1 in 2.5
6	70 %	1 in 1.4
7	> 99 %	> 1 in 1.01

3.2 Summary of Results

24 climate parameters covering temperature, precipitation, wind and lightning hazards were considered within the climate analysis. However, four of them were not carried forward in the vulnerability assessment due to data availability issues or relevance[14]. Table 3-2 provides a summary of the climate data results. Relevant climate parameters and infrastructure thresholds (climate parameters) to be used in this study are listed. For these climate parameters, historical and future probabilities of occurrence, as well as PIEVC probability scores for annual and study period probabilities are presented.

Table 3-2 Climate Parameters and Thresholds, Occurrence Probabilities and PIEVC Scoring

Climate Parameter	Threshold	Annual Probability (Historical; **Projected 2030 and *2050***)	Probability of Occurrence Study Period (2015-2050)	PIEVC Scoring		
				Historical	2030's & 2050's	Study Period
Daily Maximum Temperatures	25°C	66 per year; **84 per year**, ***106 per year***	100%	7	7	7
	30°C	16 per year; **26 per year**, ***47 per year***	100%	7	7	7
	35°C	0.75 per year; **3 per year**, ***8 per year***	100%	6	7	7
	40°C	~0.01 per year[15]; **0.3 to 2 days per year, *1-7 days per year***	~100%	1	4 - 7	7
High Daily Avg Temperature	30°C	0.07 per year[16]; **N/A, *1.2 days per year***	~100%	3	7	7
	35°C	*Zero* occurrences historically; ***zero* occurrences *projected***	0%	0	0	0
Heat Wave	3 days max temp over 30°C	0.88 per year; **>1 for both**	100%	6	7	7
High Night time Temperatures	Nighttime low ≥23°C	0.70 per year; **7 per year, *16 per year***	~100%	6	7	7
Extreme Rainfall	100 mm in <1 day + antecedent	0.04 per year; ***extreme precipitation expected* ↑, *percentage unknown***	~75%-85%	2	3	6

[14] The climate parameters not evaluated in the vulnerability assessment were high daily average temperature above 35°C (relevance), 6 hr+ freezing rain (relevance, as no ice accretion threshold was known), Minor ice accretion and deicing agents (complex interaction, no projection data available) and tree growth, pest and disease (complex interaction, no data available).
[15] Based on data from Toronto City Center station rather than Pearson Airport.
[16] Based on 4 occurrences since 1961 at Pearson Airport; see discussion in text for further details.

Climate Parameter	Threshold	Annual Probability (Historical; **Projected 2030 and *2050***)	Probability of Occurrence Study Period (2015-2050)	PIEVC Scoring		
				Historical	2030's & 2050's	Study Period
Ice Storm/Freezing Rain	15 mm (tree branches)	0.11 per year; **>0.13 per year, *>0.16 per year***	>99%	3	3	7
	25 mm ≈ 12.5 mm radial	0.06 days per year; **>0.07 per year, *>0.09 per year***	>95%	2	3	7
	60 mm ≈ 30 mm radial	High Risk: 0.007 events per year; **>0.008 per year; *>0.01 per year*** Low Risk: 0.002 events per year; **> 0.0023 per year; *0.003 per year***	High: ~25% Low: ~8%	0-1	0-1	2-4
	6 hours + freezing rain	0.65 days per year; **~0.75 per year, ~*0.94 per year***	100%	5	6	7
High Winds	70 km/h+ (tree branches)	21 days per year***;*** **N/A, *24 to 26 per year***	100%	7	7	7
	90 km/h	2 days per year; **N/A, *>2.5 per year***	100%	7	7	7
	120 km/h	~0.05 days per year; ***likely ↑, but % unknown***	~85% or higher	2	2	7
Tornado	EF1+	1-in-6,000; ***Unknown, no consensus***	~0.6%	0	0	1
	EF2+	1-in-12,000; ***Unknown, no consensus***	~0.3%	0	0	0
Lightning[17]	Flash density per km km^2	1.12 to 2.24 per year per km^2; ***Expected increase, % change unknown***	~50-70%(Lg); ~10-20% (Sm)	Lg - 2 Sm - 0	n/a	Lg – 6 Sm - 3
Snowfall	Days w/ >10 cm	1.5 days per year; ***Trend decreasing but highly variable***	100%	7	7	7
	Days w/ > 5cm	5 days per year; ***Trend decreasing but highly variable***	100%	7	7	7
Frost		229 frost free days; **249 frost free days, *273 frost free days***	100%	7	7	7
Complex Interactions	Minor ice accretion + deicing agents	***Projections unavailable***	N/A		N/A	
Complex Interactions	Changes in tree growth, disease conditions	***Projections unavailable***	N/A		N/A	

3.3 Data Sufficiency and Recommendations

The primary sources of information used in this climate data work were:

- Environment Canada Weather Station Data;
- IPCC AR5 quality controlled GCM output;
- TRCA environmental data and observations (TRCA 2014).

The climate data available for this study was judged to be sufficient to cover the majority of climate related stresses to electrical distribution systems (stemming from temperature, precipitation and wind). The study area of the City of Toronto also benefited from having good quality, long-term climate data that covered most areas of the city for these types of climate parameters. While further studies, in-depth analyses, and data quality improvements can be made (see Chapter 7), the climate data that was available was sufficient to support the risk assessment.

[17] Note that "Lg" and "Sm" refer to large and small transformer stations, see Appendix B for more details.

4 Vulnerability Assessment Methodology

The vulnerability of the electrical system to climate parameters was initially completed by employing a screening level risk based methodology (risk assessment) to identify low, medium and high risk interactions. The level of risk was evaluated based on the probability of occurrence of a climate parameter coupled with the severity (consequence) of the impact on the system and on electrical service provision. Low risk level interactions were generally judged as not being a significant issue for Toronto Hydro. Medium level risks were evaluated through a further engineering analysis to determine whether the interaction resulted in vulnerabilities (or part of a general pattern of vulnerability). Finally high risk level interactions were deemed as vulnerabilities for Toronto Hydro.

The general procedure for the risk assessment is described in Step 3 of the Protocol. However, study specific considerations (e.g. the *systems level approach*), adaptations and guidance for completing the risk assessment are described in the following chapter. Completion of the risk assessment follows the "Consultant Option" of the Protocol[18]. Notably in this option, AECOM completed the risk matrix through internal meetings with its own electrical engineers. This information was then validated with Toronto Hydro staff in a workshop held on October 10, 2014, at Toronto Hydro's offices.

4.1 Risk Tolerance Thresholds

The risk tolerance thresholds employed within this analysis conform with the proposed thresholds of the Protocol as given in the table below. These thresholds were validated with Toronto Hydro at the workshop.

Table 4-1 Risk Tolerance Thresholds

Risk Range	Threshold	Response
< 12	Low Risk	Monitoring or no further action necessary
12 – 36	Medium Risk	Vulnerability may be present. Action may be required, TBD through engineering analysis
> 36	High Risk	Vulnerability present, action required

4.2 Yes/No Analysis

The first consideration of the risk assessment is to identify whether a climate parameter will interact with the infrastructure system under consideration. A Yes/No analysis column for each of the 20 climate parameters is included in the risk assessment matrix presented in **Appendix D**. A "No (N)" result means that there is no interaction between the climate parameter and infrastructure system, while a "Yes (Y)" result means that there may be an interaction. The severity assessment is conducted only for "Yes" interactions.

4.3 Infrastructure Performance Responses - Systems Level Approach

As mentioned in the introduction, this study adopts a *systems level approach* to the analysis of climate change impacts on Toronto Hydro electrical distribution infrastructure due to the extensive, complex and interdependent nature of the electrical system. The severity of impact is evaluated based on the consequences of the interaction of different weather events with the systems and subsystems under study.

The relevant infrastructure performance responses remain the same as presented in the pilot case study. Notably, they are:

- Structural design - *Structural integrity, cracking, deformation, foundation anchoring, etc.*

[18] This approach, rather than the facilitated option, was adopted in this study because it was more efficient; the learnings gained from the pilot case study provided AECOM with the necessary insight to complete the risk assessment on its own prior to validation with Toronto Hydro.

- Functionality - *Effective load capacity, efficiency, etc.*
- Serviceability - *Ability to conduct maintenance or refurbishment, etc.*
- Operations, maintenance and materials performance - *Occupational safety, worksite access, operations and maintenance practices (frequency and type), etc.*
- Emergency Response - *Planning, access, response time*
- Insurance Considerations (Toronto Hydro perspective) - *claimable for repair, cause 3rd party payment, affect insurance rates*
- Policy and Procedure Considerations - *Planning, public sector, operations, maintenance policies and procedures, etc.*
- Health and Safety - *Injury, death, health and safety of Toronto Hydro employees, the public, etc.*
- Social Effects - *Use and enjoyment, access, commerce, damage to community assets (buildings), public perception, etc.*
- Environmental Effects - *Release or harm to natural systems (air, water, ground, flora, fauna)*

It is clear that within a *systems level approach*, weather interactions with infrastructure systems can solicit a range of different performance responses, as well as responses of differing degrees (i.e. intensity) from different components. In other words, some components within a system are more sensitive to certain types of weather events than others (e.g. heat affects the operation of transformers more than it affects the wooden pole on which the transformer is attached).

In order to conduct a logical, structured analysis, the proposed *systems level approach* identifies the infrastructure performance response stemming from the component (e.g. pole, transformer, power line, switch, etc.) which constitutes the weakest link in the system category for a given weather parameter. The component whose functionality, capacity, structural integrity or operation is affected or compromised the most, which in turn may cause other interdependent components or the entire system to cease to operate, fail, or lose capacity, constitutes the weakest link in the system. For example, the failure of a station power transformer due to high temperature and load may cut off electricity service, irrespective of what the heat may do to other equipment and structures. The station power transformer is thus considered to be the most sensitive and weakest link under high heat conditions.

As the primary role of Toronto Hydro's electrical distribution infrastructure is to provide electricity, one primary guiding criteria was used to determine which component(s) within the major systems categories constituted its weakest link: the component which, due to an interaction with a weather event, resulted in damage/failure of that component, which in turn compromised the ability of the system to deliver electricity to customers safely and securely. The risk assessment matrix presented in **Appendix D** contains a column named "consequence" which identifies the weakest link component and the anticipated infrastructure performance response.

4.3.1 Consideration of Redundancy and Station Capacity

While a component malfunction or failure may compromise the system's ability to provide electricity safely and securely, a *systems level approach* allows system design characteristics to mitigate this impact. Two notable characteristics of electrical systems are considered by this study: redundancy and station capacity.

Redundancy is the duplication of equipment and systems that afford an alternative way to deliver electrical services in the event of equipment damage or failure. In electrical systems, redundancy is provided through the presence of similar or identical equipment operating in parallel or kept on standby, and is a key component of essential infrastructure services such as electricity provision. Station capacity indicates that a station possesses capacity in excess of normal demand (i.e. under normal circumstances).

Redundancy and station capacity are characteristic of the different types of electrical systems under study. As redundancy and station capacity can mitigate component failures (i.e. allow systems to continue to provide electricity despite equipment failure in one area), they are used as mitigating factors which can attenuate severity scores. The explanation of how redundancy and station capacity are evaluated for each of the major systems categories is in presented in the sections below.

Transmission Stations

A station's ability to mitigate the system's vulnerability to climate is most usefully considered with respect to high temperatures. During high temperatures, stations with greater excess capacity will be able to continue to supply electricity despite increased demand, while stations with less excess capacity may have to reduce demand (e.g. shed load through temporary forced outages) in order to operate station equipment acceptably (e.g. to avoid overheat and burnout).

Transmission station capacity is based on the load projection exercise completed by Toronto Hydro for this project. This study is briefly described in **Appendix F (**Also see Chapter 2, *Load projections*, for more information)*.* Station capacity is rated as low or good based on the load cut-offs shown in the table below. If the station capacity is rated as low by the end of the study period (2050's), its severity evaluation for high temperature parameters is increased by ''+1''.

It is possible that excess station capacity can also be considered as a mitigating factor in the event of freezing rain, flooding, high winds, etc. For example, if a high wind event causes flying debris to damage an outdoor station, an adjacent station can help by picking up some of the load. In this case, it is the capacity of adjacent stations which helps determine the vulnerability of a service area. In the horseshoe area, station and feeder ties between service areas allow some of the load to be transferred[19]. However, this factor is not considered in the present study because adjacent stations can only take on a small portion of a faulted station's load (i.e. no station is designed to take the full load of an adjacent station, otherwise it would be overdesigned), nor are there sufficient feeder or station ties to allow the complete transfer of the load. Thus, large portions of a service area may still be susceptible to an outage at its transmission station in spite of the fact that an adjacent station has excess capacity.

Table 4-2 Severity Rating Based on Station Capacity by the 2050's

Severity Rating	Station Projected Load by the 2050's
Low (+1)	≥ 95 % (Toronto) and ≥100% Horseshoe Area
Good (no change)	< 95 %

Municipal Stations

The redundancy of the municipal stations is based on geography, and only considered for high temperature parameters for the same reasons as listed above under transmission stations. According to Toronto Hydro, if a municipal station is located in the Former Toronto area, it is generally considered that the station has less transfer capability than a station located in the horseshoe area. Severity ratings for all municipal stations in the Former Toronto area are increased by ''+1'' to reflect the low station transfer capacity in the event of a problem. This severity increase for former Toronto area municipal stations does not apply to other climate events such as freezing rain or wind because these stations are generally located indoors in the Former Toronto area.

The Toronto Hydro to Private ownership stations are dedicated to the owner. There are no transfer capacities to another station. A ''+1'' is added to the severity rating for high temperature parameters.

[19] Recall that at present, there are no station ties between station service areas in the Former Toronto area. The addition of station ties in this area is constrained by the fact that infrastructure is older, located in a dense built urban environment, and generally underground. At present, Toronto Hydro is considering the addition of station ties in the Former Toronto area, but this is not considered in this risk assessment due to its preliminary nature of this idea. In the horseshoe area, station ties allow stations to provide some load relief to adjacent service areas when required.

Underground Feeders

The redundancy of the underground feeders is based on the configuration of the feeder and its location in the city. Dual radial and residential feeders in the Former Toronto area are considered to have the lowest redundancy and capacity because structures are older, more stressed by higher loads, and are installed with less space between the conductors. The arrangement of the conductors is important because the ampacity of conductors are sensitive to the heat generated by nearby conductors. Severity ratings for these feeders are increased by ‘’+1’’ as a result (Table 4-3).

Table 4-3 Severity Rating Based on Feeder Configuration

Severity Rating	Increasing Levels of Feeder Redundancy
Low (+1)	Dual Radial & URD : Former Toronto
Moderate (no change)	Dual Radial & URD : Horseshoe
Good (no change)	Compact Loop Design
Best (no change)	Network

Overhead Feeders

The redundancy of the overhead feeders is considered between two configurations: radial or loop. Radial lines cannot be backed-up in the event of a fault, while loop configurations could allow electricity to be brought in through the “other side” of the loop. For this purpose, the severity ratings for radial feeder configurations are increased by ‘’+1’’.

Communications Systems

The redundancy evaluation is not considered for the communications systems, as they do not mitigate circumstances of loss of electrical service provision.

Civil Structures

Historically, infrastructure built for the distribution of electricity in the City of Toronto were concentrated in the downtown core and inner city and later extended to the horseshoe area. Part of the electrical equipment was replaced over time but much of the civil structures (e.g. underground vaults) remain in place due to their expected lifespan (35 - 60 years). It is thus assumed that the civil structures in the Former Toronto area are older and more degraded than the structures in the Horseshoe Area. A ‘’+1’’ severity scoring is added to the Former Toronto civil structures.

4.4 Scoring Severity

The severity scoring exercise is conducted using the scoring scale defined by the Protocol, method D. Examples of impacts on different equipment were developed in the course of this analysis. In addition to the guidance provided by the Protocol on severity scoring, this study provides a further, electrical system specific consideration in severity scoring. Two complementary, severity scoring scales were developed for this study to reflect the severity scoring differences between stations and feeder systems. As stations represent major nodes in the distribution of electricity, an affected or disabled station could result in a loss of service on all downstream feeder systems and customers. However, if a feeder branch or sub-branch is affected, only the customers on the branch or sub-branch may be affected. Thus, the impacts on station equipment are judged to be more severe than impacts on feeder systems. The severity scoring scale employed in this study, as presented below, reflects this general consideration.

Table 4-4 Severity Scoring Scale for Electrical Distribution Systems

Score	Stations			Feeders	
	Method D	**Descriptive**	**Examples**	**Descriptive**	**Example**
0	No Effect	Negligible or N/A		Negligible or N/A	
1	Measurable	Very Low - Some measurable change		Some loss of serviceability & capacity, no loss of function	*Arrestor failure, overheating cables, salt deterioration of civil/electrical equipment*
2	Minor	Low - Slight loss of serviceability	*Station battery – lifespan shortened*	Some loss of capacity & function	*Overheating transformer from high load*
3	Moderate	Moderate loss of serviceability, some loss of capacity, but no loss of function	*Station transformer heating up, but possibility of meeting demand from another station*	Moderate loss of function	*Broken spring in underground switchgear, distribution transformer out (must replace), cable*
4	Major	Major loss of serviceability, some loss of capacity & function	*Station transformer heating up, need to do load shedding*	Major loss of function of multiple equipment – localized	*Transformer and switchgear out (replace multiple equipment)*
5	Serious	More loss of capacity & function	*Station transformer heating up, need to do load shedding for longer duration*	Major loss of function of multiple equipment – wide area	*Transformer and Switchgear out Flooded vault that cannot be pumped*
6	Hazardous	Major - Loss of Function	*Loss of CT/VT transformer, battery assets*	Major loss of function of multiple equipment – wide area	*Leaning pole/downed line*
7	Catastrophic	Extreme – Loss of Asset	*Station trans. failure*	Major loss of function of multiple equipment – wide area	*Downed pole, line and transformer*

4.5 Mapping Risks

Due to the sheer number of similar assets and their distribution across the city, study authors and Toronto Hydro have elected to map climate change risks to the electrical distribution system in the City of Toronto. It was decided that two main asset classes would be included in the risk map: stations and feeders. The risks to supporting infrastructure, such as communication systems and civil structures, were difficult to represent on such a large scale. Furthermore, the risks to these systems are generally associated with, and can be adequately illustrated by, the risks to the stations and feeder systems.

The risk mapping exercise was completed using the geographic information systems (GIS) resources provided by Toronto Hydro. AECOM provided the final risk assessment matrix results to Toronto Hydro's GIS team. Each of the station and feeder assets in the risk assessment matrix were identified on GIS maps. Stations were illustrated as polygons representing the stations' service areas rather than as points where stations are located. This was done in order to illustrate the fact that faults at a station can affect an entire service area. Feeder systems were illustrated as line vectors on the map. Next, the low, medium or high classification of station or feeder risks were represented by colouring the assets class representations (polygons or lines) in yellow, orange or red to denote low, medium and high risks respectively. Where there were no interactions between climate and infrastructure, asset representations were coloured in grey. Finally, white spaces within the City of Toronto generally indicate where no electrical service is provided. Results of the risk mapping exercise are presented in Chapter 5 and in **Appendix E**.

5 Assessment Results

This chapter presents a summary of anticipated impacts from the interaction of climate events with electrical distribution system infrastructure resulting in low, medium and high risk interactions. In addition, special case risks are also presented.

5.1 Low Risk Interactions

High Temperature

SCADA systems may be affected by ambient air temperatures above 40°C. According to equipment design specifications (S&C manufacturer, 2011), such temperatures constitute unusual conditions for the interrupters within the SCADA system. At high temperatures over 40°C, the accuracy of power line current and voltage sensors, as well as the ability to provide DC voltages for the control of the switch, are not assured. SCADA system equipment are tested to operate between -40°C to +40°C. However, other components of the SCADA system like the communication and control unit can operate at temperatures up to +70°C. A low risk score was given considering that the SCADA switch is able to operate in temperatures above 40°C, but its performance (accuracy of sensors) may decrease.

Extreme Rainfall

Extreme rainfall poses a low risk to certain underground feeder systems in the horseshoe area. Underground feeder systems with some equipment located in above ground vaults or on padmounts may be affected by localized flooding due to extremely rainfall. This creates an issue in terms of accessing equipment.

Some transmission stations in the Former Toronto area currently have batteries and switchgear located below grade. This equipment could be damaged if flooding occurred. Toronto Hydro is currently moving its battery assets above grade when they reach the end of their lifecycle (typically 10 – 12 years). By the 2030's, it is expected that all station batteries will be moved above grade. Some of the switchgear equipment will also be moved above grade, although stations in the Former Toronto area may face space constraints to moving all equipment above grade. As such, it is likely that some switchgear will still be located below grade by the 2030s. However, stations are equipped with multiple sump pumps which can evacuate water that flows into the basements. According to a Toronto Hydro representative, there have been no flooding incidents to Toronto Hydro stations owing to heavy precipitation over the last several decades due to the pump and drainage systems found in stations. Based on expected work to relocate batteries and certain switchgear, and continued adequacy of sump pumps, the risk of flooding from extreme rainfall for transmission stations in the Former Toronto area was rated as a low risk.

Freezing Rain

For stations, 15 mm or less of freezing rain are not expected to create sufficient ice loads to cause structural problems. Freezing rain could cause some delays in accessing equipment (e.g. ground or equipment encrusted with a layer of ice), although this was judged to be of low risk by workshop participants

Snow

Snow accumulation and snow fall, especially for days with >10 cm of snow, can also cause visibility and access issues. Access to padmounted transformers and switches, as well as underground vaults may be hampered by snow pushed aside from road and sidewalk snow clearing equipment, thereby lengthening the time needed to access equipment. However, access issues from snow were judged to be of low risk by workshop participants.

Frost

Frost may cause the displacement of the ground (frost heave) and compromise the stability of the foundations of poles, vaults and cable chambers. Frost heave events are generally localized, and do not tend to disrupt electrical service. Furthermore, the number of frost free days are expected to increase by 2050 due to increases in annual temperatures. For these reasons, frost was judged to be of low risk. Civil structures located in the former Toronto area were given a slightly higher (+1) severity rating (and therefore risk rating) because the infrastructure is generally older than those found in the horseshoe area.

5.2 Medium Risk Interactions

High Temperature

High ambient air temperatures starting at 25°C and above are responsible for the majority of medium risks evaluated within this study. Unless stated, the temperatures presented below exclude consideration of humidity on felt temperature (i.e. humidex). From an electrical equipment point of view, it is the ambient air temperature, not humidity, which impacts the structural integrity or lifespan of equipment. Humidity, coupled with high ambient air temperatures may result in higher felt temperatures by people, which in turn can increase the demand for air-conditioning. However, risks posed by high temperatures to infrastructure are evaluated in terms of their design and performance characteristics (ability to shed heat or cool down), which are not affected by humidity levels. High humidity was considered when evaluating the risks to Toronto Hydro personnel.

High temperatures affect the lifespan of station batteries. Where the air temperature of rooms that house station batteries exceeds 25°C, the lifespan of the batteries will begin to degrade. This will result in the long-term in the replacement of batteries sooner than expected. The buildings containing the rooms where batteries are stored afford some protection from changes to external air temperatures. This means that an external air temperature of 25°C may not immediately trigger the premature degradation of batteries. However, rooms where batteries are stored are not temperature regulated, and the impacts to battery lifespan will increase as external air temperatures increase above 25°C. Heat impacts on station battery lifespan were judged to be of medium risk.

As maximum daily air temperatures exceed 35°C, station power transformers will be the most critical pieces of equipment to be affected. First, the use of air-conditioning will increase, thereby increasing the electrical load on transformers. Transformers will heat up, but warm ambient air temperatures also reduce the effectiveness of natural or mechanical cooling. Stations with low projected excess capacities by the 2030’s and 2050’s will be less able to meet additional demand during periods of high temperature because of higher existing base load. These include transmission stations located in downtown areas, as well as Bathurst station, Sheppard, Leaside, Rexdale, Woodbridge, Manby and Horner. These were judged to be slightly more at risk (+1 severity) as compared to other stations in the East and Northwest sub-service areas.

Heat waves, when the daily maximum temperature during three consecutive days exceeds 30°C, as well as warm nights (minimum temperatures ≥ 23°C) both constitute medium risks for station power transformers. High night time temperatures will result in continued electrical use for air-conditioning, and also decrease the potential for transformers to cool down overnight. However, overall electrical demand is lower at night than during the daytime, and Toronto Hydro staff did not consider high night time temperatures to be as significant a concern as high daytime temperatures or heat waves from an electrical system point of view (Workshop 2).

High temperatures above 40°C, average temperatures over 30°C on a 24h basis, heat waves and high night time temperatures were also judged to be a medium risk for underground and overhead feeder systems due to high electrical demand for cooling and high ambient temperatures. Cables and power transformers were the two most vulnerable parts of these feeder systems in terms of heat. Under high demand, underground conducting wires and their housing undergo thermal expansion. This affects the structural integrity of the housing by causing wear and potentially leading to microfractures that are susceptible to water infiltration. Underground cables laid in close proximity or side by side, as is the case for underground feeders in the denser Former Toronto area, are also more susceptible to these expansion effects than underground feeders in the horseshoe area. Adjacent cables tend to heat one another up, and the increased heat reduces the cables' electrical transmission capacity. In overhead systems, cables under high demand will also lead to cable expansion and conductor sag. While this sag is generally accounted for in tree trimming and object clearance around power lines, excessive sag may be more prone to contacting objects and causing an electrical fault.

Feeder system power transformers are affected in a similar manner as their station counterparts. High ambient temperatures place additional demand from air-conditioning on transformers, while also affecting their ability to effectively cool. Overheating overhead transformers may fail or catch fire and will have to be replaced. In terms of relative risk, it should be noted that an overheating feeder line power transformer is less critical than an overheating station transformer, as the former serves fewer clients than the latter.

Underground dual radial, URD, compact loop and network systems afford increasing levels of redundancy for clients, due to their ability to supply electricity in the event of an outage through a different branch, loop or conduit of the feeder system. In this study, dual radial and URD feeders in the Former Toronto area were considered to be less able to cope with high electrical demand and mitigate outages than similar electrical feeder types in the horseshoe area. This is due to the fact that feeders in the Former Toronto area are already under high base load (denser environment), their equipment is generally older and cables running side by side increase the heat load and reduce their maximum capacity. Therefore, underground feeders in the Former Toronto area are considered to be slightly more at risk (+1 severity) to heat impacts as compared with similar feeder types in the horseshoe area.

Overhead feeder systems were judged to be slightly more at risk (+1 to +2 severity) than underground systems to temperatures above 40°C and to average temperatures above 30°C on a 24h basis. While electrical load demands may be similar for underground and overhead transformers, direct solar radiation and exposure to high ambient air temperatures can reduce the ability of overhead transformers to disperse heat. On the other hand, overhead transformers were judged to be less vulnerable to high night time temperatures than underground systems, due to increased circulation of cooler nighttime air around overhead transformers as compared to those located in underground vaults.

High ambient air temperatures were also judged to be medium-low risks for protection and control systems. Like station batteries, high temperatures will degrade the expected lifespan of batteries used to power the feeder protection and control systems in the event of a power failure.

Extreme Rainfall

The most significant medium risks from extreme rainfall events are related to the flooding of non-submersible vault-type electrical components kept below grade. Vaults below grade are usually equipped with either passive drainage systems or active pumping drainage systems to keep them from flooding. However, under extreme rainfall conditions, it is possible that the sewers to which these drainage systems are connected may themselves be at capacity, and without the ability to evacuate the water, some vaults may flood. In flooded vaults, non-submersible electrical equipment could be damaged, and an outage may occur. This is also a concern in some network type feeders in downtown Toronto, where old network protection equipment are not housed in submersible enclosures. Toronto Hydro is gradually installing submersible equipment in all below-grade vaults, but non-submersible equipment is still expected to be in present by the end of the study period. Furthermore, the equipment in flooded vaults cannot be accessed until the water is evacuated, creating a delay in responding to electrical incidents.

While not exclusively a problem related to heavy rainfall events, water infiltration into the ground and moisture around underground cables can lead to water treeing[20] and cracking of cable insulation. Deterioration of cable housing could lead to electrical faults if cracks become sufficiently large to allow ground moisture to serve as a pathway for electricity to ground.

[20] Tears in the cable's insulating layer caused by the presence of moisture and an alternating current's (AC) electric field.

It was noted in the workshop that extreme rainfall can be beneficial to overhead feeder systems. Salt residues from the wintertime and dust throughout the year can accumulate on electrical insulators. Moist conditions such as fog, mist or light rainfall can cause these accumulations to serve as conduits to ground, causing flashovers and potential pole fires and outages. Heavy rainfall events, especially in the early spring, are in fact beneficial for washing off the salt and dirt residues from insulators. Note that 27.6 kV and 13.8 kV lines are more prone to flashovers due to their higher voltages. It was noted in the workshop that 27.6 kV systems in particular may require more frequent cleaning than is currently the case in order to prevent flashovers, while flashovers do not tend to occur with 4.16 kV equipment.

High Winds

High winds over 70 km/h (but less than 90 km/h) were considered a medium risk to overhead power lines. While lines and poles are designed to withstand such wind speeds, it has been found that tree branches may begin to break at these thresholds and fall onto lines. Overhead conductors may also flail in the wind and contact branches. At the least, these tree contacts may cause momentary interruptions to electrical service. At the worst, tree branches and limbs may fall on and damage or sever power lines, potentially causing outages, fires and public safety hazards.

Lightning

Lightning strikes on overhead feeder systems was rated as a medium risk. Lightning arrestors installed on overhead power lines are designed to direct lightning surge currents to ground and protect pole mounted equipment such as transformers, switches and SCADA equipment. However, failure of the lightning arrestors can result in damaged equipment from lightning strikes and potentially lead to a localized outage.

Human Resources

Most of the human resource interactions with climate parameters (high heat, heavy precipitation, 15 mm of freezing rain, high wind, tornadoes, lightning and snowfall) were judged to be of medium risk. High heat conditions can make it dangerous to work on outdoor and overhead equipment for extended periods of time. For underground systems, high ambient temperatures can exacerbate hot conditions in vaults (heated by transformer operation), thereby also making it unsafe to work on equipment for extended periods of time. Workers tend to defer work under high heat conditions until temperatures above ground or within vaults cool sufficiently to allow safe continuous access. This may however cause a delay in the response to incidents on the electrical system.

Heavy precipitation, freezing rain and snowfall may make it difficult for all employees to travel to and from work, while also making it dangerous for field workers to get to equipment. During severe events such as high winds, tornadoes and lightning, workers apply their judgement and generally delay accessing equipment until the severe weather event has passed. Interestingly, the severity scoring of high winds at 70 km/h were slightly higher than scores for higher wind speeds (90 km/h, 120 km/h or tornadoes). This is because unsafe work conditions are very clear under extreme high wind events. However, at lower wind speeds, work conditions may appear to be acceptable, and workers may decide that the threat is reasonable given the need to restore electrical service. However, sudden, abrupt wind gusts could momentarily jeopardize worker safety.

As Toronto Hydro has occupational health and safety policies and procedures in place, the consequence of severe weather on workers tends to be delaying access and work on equipment until weather conditions, road access improves, and worksites are declared to be safe.

5.3 High Risk Interactions

The highest risks found in this study are related to structural damage and failure of electrical systems and components. In general, station equipment and overhead feeder systems were the two main system infrastructure categories susceptible to climate interactions that yield high risk interactions.

High Temperature

Days with peak temperatures above 40°C and days where average ambient temperatures exceed 30°C on a 24h basis are the two significant climate parameters rated as high risk for transmission and municipal stations. Days with peak temperatures above 40°C are currently a very rare occurrence, but are expected to occur on an almost annual basis by the 2030's and on an annual basis by the 2050's. Similarly, high ambient temperatures exceeding 30°C on a 24h basis are currently a rare occurrence, but may occur on an annual basis by the 2050's. In both cases, high electrical demand, coupled with loss of cooling efficiency, will cause station power transformers to overheat. In the most severe of cases, demand cannot be maintained without damaging station power transformers, which have an average replacement cost of around $500 K[21]. A coping mechanism employed by electrical utilities is to shed electrical load (load shedding), which entails instituting temporary outages in various sectors of the city in order to reduce load demand. For buildings and residents dependent on air-conditioning for cooling purposes, this represents a significant public health risk at a time of extreme heat events.

This high risk is especially relevant for transmission and municipal stations with low excess capacity by the 2030's and 2050's. As such, during periods of high demand, these stations have less excess capacity with which to meet electrical demand.

Freezing Rain and Ice Storms

There are three significant thresholds to consider for freezing rain and ice storm effects on the electrical distribution system. First, preliminary forensic analyses of outages from freezing rain indicate that 15+ mm of freezing rain is a trigger for the breaking of tree branches and limbs. These pose a threat to overhead feeder systems, and these freezing rain amounts have resulted in widespread outages in Toronto in the past due to tree contacts. The next threshold is 25 mm of freezing rain, which is the CSA design requirement for overhead electrical systems. Theoretically, overhead feeder systems, as well as the overhead exit lines at stations are supposed to withstand 25 mm of freezing rain (12.5 mm of radial ice accretion). However, such quantities of freezing rain and ice accretion on overhead infrastructure bring them to their structural design limits, which are further exacerbated by breaking tree branches and wind. Finally at 60 mm of freezing rain, the weight of ice accretion on overhead lines and station exit lines exceeds their design limit, and will likely cause them to collapse.

It should be noted that the high risk ratings for 15 mm and 25 mm of freezing rain on overhead feeder systems and station exit lines is based on probability of occurrence for the study period (probability scores of 7, event will occur during the study period)[22]. From an annual probability perspective, freezing rain events at 15mm and 25mm of freezing rain would actually result in medium risk ratings. As can be seen from Table 3-2 in Chapter 3, the current annual probability of occurrence of 15 mm of freezing rain is 0.11 days / year (1 in 9 year return period), and is projected to increase to 0.16 days / year (1 in 6 year return period) by the 2050's. The current annual probability of 25 mm of freezing rain is 0.06 days / year (1 in 17 year return period), and is projected to increase to 0.09 days per / year (1 in 11 year return period) by the 2050's.As the projected trend for 15 mm and 25 mm freezing rain events is increasing in the future, the interaction of these two climate parameters with overhead feeder systems and station exit lines are maintained as a high risk.

Similarly, it was found that 60 mm freezing rain events would actually fall into a medium risk category (study period probability of 4, annual probability of 1, severity score of 7). However, major ice storms are part of a pattern of risk that is similar to 25 mm freezing rain events. For this reason, it is maintained in the high risk category

High Winds

High winds and wind gusts at 90 km/h and 120 km/h were judged to be a high risk to overhead feeder systems. These wind speeds reach and exceed the design limits of conductor connections to support poles, and the poles

[21] Estimate provided through correspondence with Toronto Hydro staff.
[22] A comparison for freezing rain/ice storm lasting at least 6hr+ based on annual probability versus study period probability does not change the high risk rating.

themselves. Further compounding impacts is the potential for flying debris, such as broken tree branches and limbs, to further bring down overhead feeder systems.

The threats from high winds and gusts above 120 km/h were judged to be high risk due to wind forces on station overhead exit lines (exceeding design standard for poles). Furthermore, there is the potential for flying debris to damage station equipment at outdoor stations.

As is the case for freezing rain, it should be noted that the high risk ratings wind over 120 km/h were on overhead feeder systems and station exit lines is based on probability of occurrence for the study period (probability scores of 7, event will occur during the study period)[23]. However, from an annual probability perspective, events producing 120 km/h high winds would actual result in low and medium-low risk ratings for station and overhead feeder systems respectively. This is because the current annual probability of 120 km/h wind events is 0.05 days per year (1 in 20 year return period). This frequency is expected to increase during the study horizon, although the projected value is not known. These significant wind events are similar to the case of tornadoes, in that they are infrequent but can lead to significant damage to large areas of the distribution system if they occur (low probability, high severity events). As they are however expected to be more frequent than tornadoes, the 120 km/h wind – overhead systems interaction is maintained as high risk in this study.

Lightning

Lightning strikes on station equipment, notably power transformers, were rated as a high risk. Lightning arrestors at stations are designed to direct lightning surge currents to ground and protect electrical equipment. However, failure of the lightning arrestors can result in damaged equipment from lightning strikes and potentially causing an outage to an entire service area.

Human Resources

Heavy freezing rain events constitute a high risk for Toronto Hydro personnel. First, slippery surfaces make travel to and from work, and out to worksites dangerous for field crews. Second, field crews also have to contend with a layer of ice over electrical equipment, trees, and other overhead structures such as buildings. As such, the risk of injury to workers from freezing rain events remain even after the storm has passed due to the continuous ice loads on overhead power lines and trees, which may cause them to break without warning.

5.4 Special Cases – High Severity, Low Probability Events

Tornadoes

Tornadoes represent a high severity, low probability event. As mentioned in Chapter 3, while the likelihood of a tornado event touching down at a specific point or location is extremely small, the likelihood of a tornado occurring somewhere in the City of Toronto over study period (2015 – 2050) is in fact considerable. Furthermore, due to the lake breeze effect, northern portions of the city tend to have a high probability of seeing a tornado event, although it does not preclude an occurrence closer to the lakeshore. Tornadoes were judged to have catastrophic consequences on all above ground infrastructure, while underground infrastructure may become inaccessible due to windblown debris.

[23] A comparison for freezing rain/ice storm lasting at least 6hr+ based on annual probability versus study period probability does not change the high risk rating.

5.6 Special Cases – Low Severity, High Probability Events

Snowfall and freezing rain

The degradation of concrete and corrosion of steel materials (at grade and underground feeder systems) is a case of high probability, low severity events. These processes are accelerated by the application of de-icing salts during snowfall and freezing rain events. The application of salts can accelerate the corrosion of metal housing and enclosures of electrical equipment, resulting in shorter lifespans. It also affects the steel and concrete of vaults and cable chambers (civil equipment). Future warming associated with climate change is expected to decrease the number of days without snowfall, but the trend for freezing rain is expected to increase. Nonetheless, snowfall is expected to continue to be an annual event throughout the time horizon of this study. As such, degradation of civil structures will continue to be an issue for Toronto Hydro over the study period.

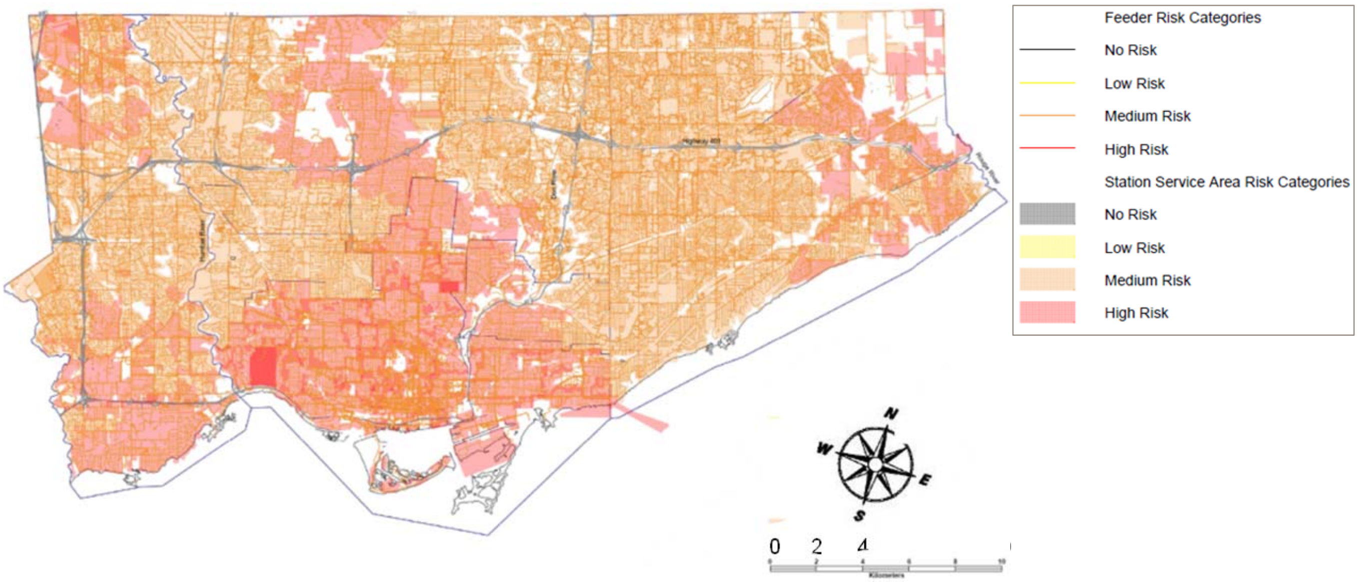
Underground electrical feeder equipment and civil structures located in the Former Toronto area received a slightly (+1) higher severity rating (and a medium-low risk rating) because the infrastructure is generally older than those found in the horseshoe area. It was found that older equipment and structures are more susceptible to degradation if corrosion had already begun (e.g. protective layers of paint may be worn off). Furthermore, older equipment may not be as resistant to corrosion as newer equipment due to the advancement of enclosure design and testing over time (Nema standard).

Some of this salt is dispersed by the moisture in the air, and can accumulate through the winter season on insulators on poles. These salt accumulations can cause electrical short circuits that could result in pole fires. Loop feeder systems are judged to be of lower risk than radial systems in the event of a short circuit or fire due to the potential to provide power temporarily through another loop of the feeder.

5.7 Mapping Risk Results

The mapping of risks provides complementary information to the risk assessment matrix, and facilitates a spatial understanding of low, medium and high risk interactions, and vulnerabilities (i.e. the medium and high risk interactions). For example, maps can provide an indication of the areas of vulnerability of overhead and underground infrastructure with respect to different kinds of weather events. Furthermore, the mapping exercise actually provides a new set of information on how vulnerabilities stemming from stations can combine with vulnerabilities to feeder systems. In some cases, vulnerabilities stem primarily from station assets (e.g. 120km/h wind and underground feeder assets), while in other cases, both station and feeder vulnerabilities to weather events contribute to an area of greater vulnerability within the city (i.e. freezing rain affecting both station and overhead feeder assets). The following section provides some spatial observations about the four climate parameters affecting electrical distribution infrastructure. All mapping results are provided in **Appendix E**.

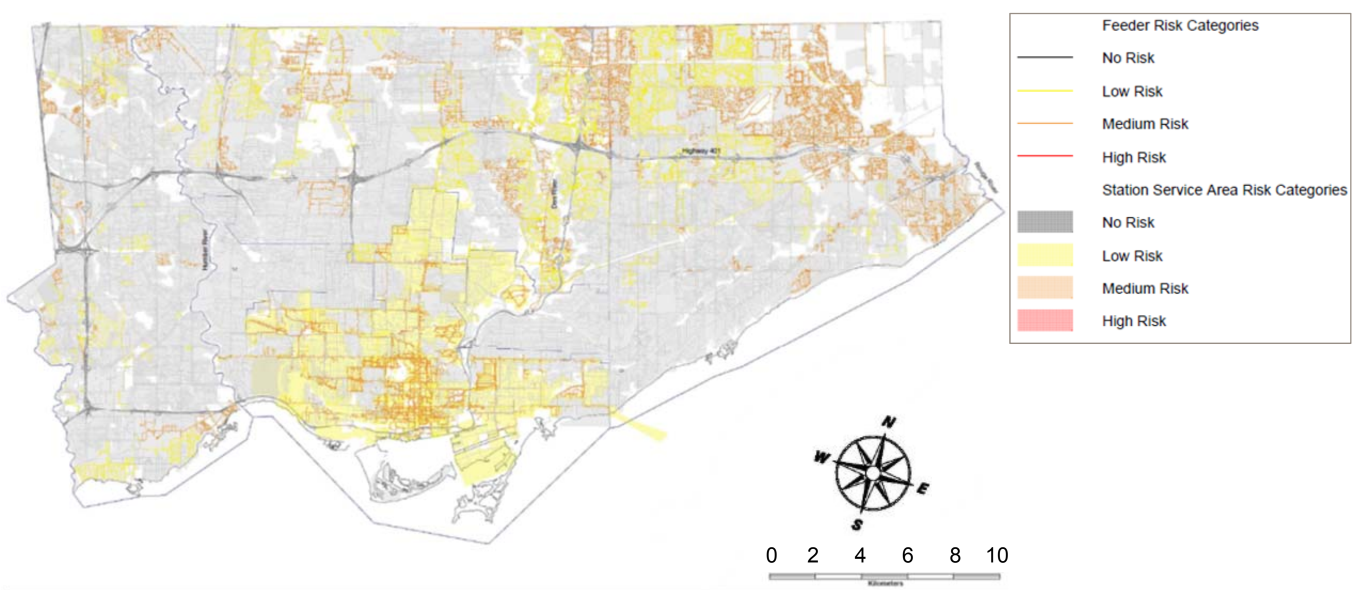
Figure 5-1 Risk Map, High Temperature Above 40°C, 2050's



Vulnerabilities from high heat events stem primarily from projected available station capacity by the 2050s, as this study did not find that vulnerabilities varied significantly (all rated medium risk) for feeder assets. Vulnerabilities to high heat events are more heavily concentrated in the Former Toronto area, although several horseshoe area stations would also be vulnerable during high heat events (Figure 5-1).

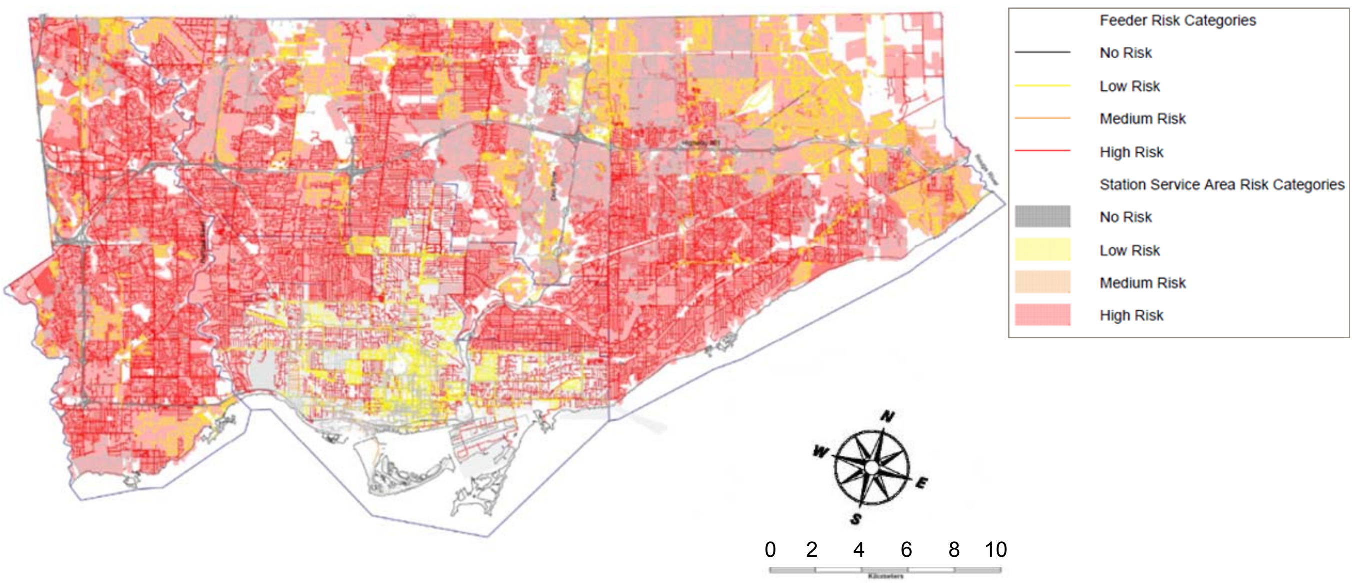
In terms of potential heavy rainfall risks to Toronto Hydro infrastructure, underground feeder systems that may be subject to flooding are located largely in the Former Toronto area and northeastern sections of the horseshoe (Figure 5-2). Some transmission station service areas in the Former Toronto area are marked as low risk due to the presence of some switchgear equipment that will likely remain in basements through the study period. Note however that sump pumps in stations make the probability of flood damage in stations from heavy precipitation less likely.

Figure 5-2 Risk Map, Extreme Rainfall, 100 mm in less than 24h, 2050's



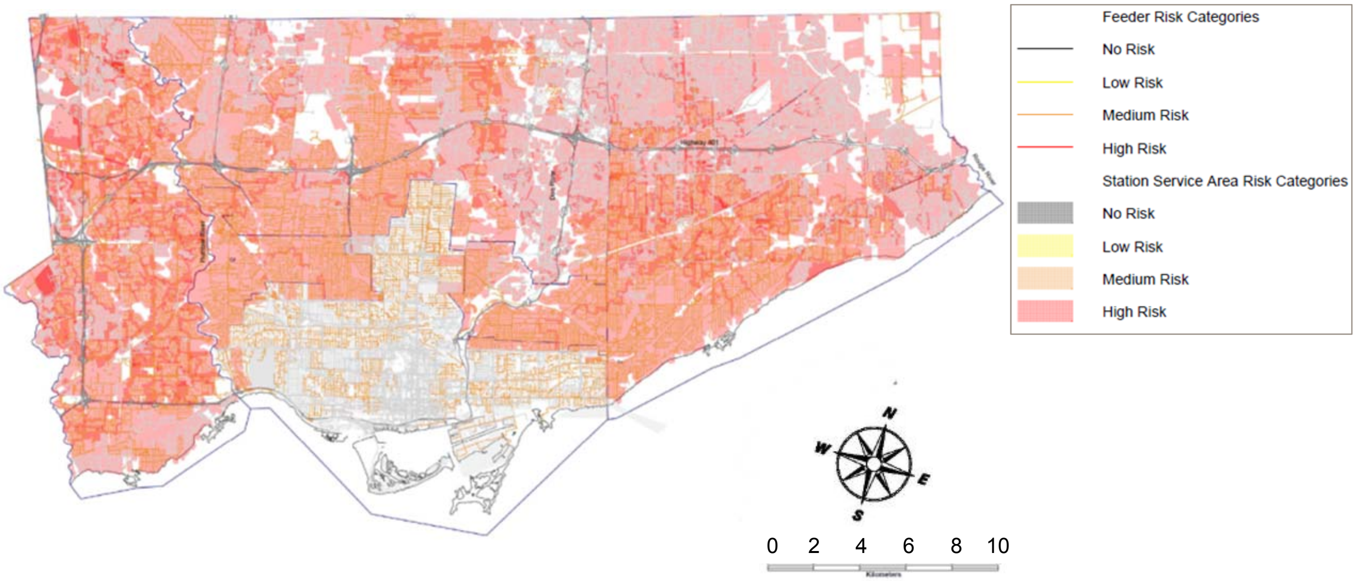
Toronto Hydro has a significant quantity of overhead distribution systems which are at vulnerable to extreme freezing rain, ice storms, high wind and tornado events. These feeder vulnerabilities combine with the fact that stations in the horseshoe area have station exit lines that are outdoors. This combination makes certain portions of the horseshoe particularly vulnerable to heavy freezing rain events and ice storm. Figure 5-3 shows the areas of vulnerability stemming from 25 mm of freezing rain, and is indicative of extreme precipitation/wind related vulnerabilities to overhead systems across Toronto.

Figure 5-3 Risk Map, 25 mm Freezing Rain, 2050's



Lightning strike vulnerabilities are largely concentrated in the horseshoe area, where both outdoor station equipment and overhead feeder systems are predominant. However, overhead feeder systems in the the Former Toronto area are also vulnerable (Figure 5-4).

Figure 5-4 Risk Map, Electrical Distribution Systems Potentially Affected by Lightning Strikes



There are several caveats that should be mentioned with respect to interpreting mapping results, due in large part to the fact that risk ratings were evaluated based on general system characteristics. Localized site characteristics that may mitigate or worsen risk ratings were not adequately captured in the mapping exercise. They include:

- Local geographic characteristics, assets and features. There may be local site characteristics such the tree canopy cover, types of trees, presence of buildings or other overhead structures, which may exacerbate weather events (e.g. wind) or shelter infrastructure from impacts. The presence of low lying areas (e.g. bowls, flood plains) was also not considered. This level of detail, provided by a full site inspection and digital terrain mapping, were not available for this project. Such information would be useful in refining the risk ratings and mapping for extreme rainfall, freezing rain and wind;

- Areas with lower drainage capacity due to configuration of city storm drainage infrastructure. This type of information requires a very detailed understanding of city infrastructure, which was not available for this study. Furthermore, this level of data is most useful when combined with digital terrain mapping in order to identify low lying areas with problematic drainage. Finally, future projections as to how city infrastructure might evolve over time were also not available for this project;

- The moderating effect of Lake Ontario. As noted in Chapter 3, the lake can play a significant role in influencing temperature and humidity along the lakeshore. For example, the lake effect can moderate temperatures during heat waves and can reduce the possibilities of freezing rain or snow falling on areas closer to the lakeshore. The extent and intensity of the lake effect can vary depending on the event and weather conditions. It was not possible to estimate the geographic extent of the lake effect, or by how much the probability scoring for certain climate parameters may be affected. As such, the lake effect's moderating influence was not taken into account sufficiently in the risk assessment and mapping exercise;

- Local electrical configurations and characteristics. There are likely cases where location specific electrical equipment may make certain feeder or station systems inherently more robust or redundant than would be the case of the general class of equipment. For example, additional feeder ties, loops or circuits could make certain feeders more redundant in the event of a downed power line. The age of equipment, their future replacement schedule will also have an effect on their risk rating. This level of detail is not captured at level of analysis undertaken in this study;

- For the extreme rainfall risk map, it should be noted that the mapping of transmission stations includes all stations. Information identifying the location of the stations whose batteries and switchgear are located below grade was not available. Further analysis is required to identify the precise locations of transmission with below grade assets in order to get a better mapping of flood related risks.

In spite of these shortcomings, the mapping exercise represents a useful first approximation of spatial nature of electrical system vulnerabilities to climate change. Furthermore, this mapping information can be more easily combined with other layers of information such as technical hazard information (e.g. flood mapping), physical locations (e.g. emergency resource centres, hospitals, transportation networks) and social vulnerability indices (e.g. age, income, population density, etc.) from other sources (e.g. TRCA, City of Toronto) to produce further mapping studies and in depth analyses to suit the needs of other policy makers.

6 Engineering Analysis

This chapter presents the results of the Step 4 of the Protocol, the Engineering Analysis. The purpose of Engineering Analysis is to conduct a further assessment of the system-climate interactions that were rated as a medium risk (interactions scoring between 14 and 35). For these interactions, the engineering analysis attempts to evaluate whether the infrastructure is vulnerable to a changing climate. To do so, the various factors that affect the load and the capacity of the infrastructure for the study time horizon are calculated. However, quantitative calculations of load and capacity were not always possible to make due to a lack of data to support such an analysis. For this reason, professional judgment is also applied in the engineering analysis. Infrastructure which is found to be vulnerable is passed to Step 5, while those which were not were discarded from further consideration.

In total, nineteen medium risk interactions were analyzed. Fifteen of them were deemed vulnerable and passed to Step 5, while 4 were discarded from further analysis. The following table summarizes the results of the engineering analysis. A brief description of the reasoning behind the results for each of the medium risk interactions is presented in this chapter, while the full engineering analysis can be found in **Appendix G.**

Table 6-1 Engineering Analysis Results

	Affected infrastructure	Climate Parameter	Further Action Recommended
	Municipal and Transmission Stations and Communications Systems		
1.	Transmission and municipal stations	High temperature above 25°C and above 30°C	Yes
	Protection and control systems	All temperatures	
2.	Transmission stations	High temperature above 35°C	Yes
3.	Transmission stations	High temperature above 40°C and average temperature > 30°C	Yes
4.	Transmission stations	Heat wave and high nighttime temperatures	Yes
5.	Transmission and municipal stations	Freezing rain, ice Storm 60 mm	Yes
6.	Municipal stations	High temperature	Yes
	Underground and Overhead Feeders		
7.	Underground feeders	High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime	Yes
8.	Underground feeders	Extreme rainfall	a. Feeders/water treeing: Yes b. Nun submersible vault: Yes c. Above ground stations: No d. N/W feeders: Yes
9.	Padmount stations	High winds 120 km/h	No
10.	Overhead feeders (radial and loop)	High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave	Yes
11.	Overhead feeders (radial)	High nighttime temperatures	No
12.	Overhead feeders (loop)	Freezing rain, ice Storm 15 mm	Yes
13.	Overhead feeders (radial and loop)	Freezing rain, ice Storm 60 mm	Yes
14.	Overhead feeders (radial and open loop) and SCADA system	Lightning	Yes
15.	Overhead feeders (radial)	Snow > 5 cm and snow > 10 cm	No
	Civil Structures		
16.	Civil structures: underground feeders (Former Toronto)	Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 6hrs+ (combination of events)	Yes
17.	Civil Structures: underground feeders (Former Toronto)	Snow > 5 cm and snow > 10 cm	No, but combinations of climates need additional study.
18.	Civil structures	Frost	Yes
19.	Human resources	All climate parameters	Yes

6.1 Municipal and Transmission Stations and Communications Systems

1. High temperature above 25°C and above 30°C / transmission and municipal stations and all Temperatures / protection and control systems

Further action recommended. Under higher temperatures, battery life expectancy (e.g. around 10 years) may decrease. Toronto Hydro has already encountered problems with some batteries failing prior to their expected lifespan..

2. High temperature above 35°C / transmission stations

Further action recommended, conclusions for high temperature and power transformers also apply (see Chapter 7). Transmission station designers will need to take into account the significant increase in days with maximum temperatures above 35°C, which reduces station capacity while, on the other hand, experiences an increased load demand. At the moment, no load growth rate for the period of this study was estimated. The recommendations given in Chapter 7 for transmission stations and maximum temperature above 40°C / average temp above 30°C also apply to this interaction.

3. High temperature above 40°C and average temperature > 30°C / transmission stations

Further action recommended. Most of the transmission stations considered in this study were judged to be vulnerable (high risk rating) to high temperatures. The stations in the Horseshoe received a medium-high risk score (35) due to the application of the concept of excess capacity, which is qualitative and notional (refer to the **Appendix F**). As such, it is recommended that transmission stations receiving a medium-high risk score be considered vulnerable to extreme high temperatures as part of a consistent pattern of risk. This will also help Toronto Hydro to adopt a consistent approach in the design, operations and maintenance of stations.

4. Heat wave (+30°C) and high nighttime temperatures (+23°C) / transmission stations

Further action recommended. Power transformers are vital equipment in the distribution of electricity and high temperatures have a significant impact on the capacity of the transformers. For these reasons, the conclusion of this report for temperature above 40°C and for high daily average temperature > 30°C are also relevant to the heat wave and high nighttime temperature parameters.

5. Freezing rain/ice storm 60 mm ≈ 30 mm radial (major outages) / transmission stations and municipal stations

Further action recommended. This interaction is part of a similar pattern of vulnerability as 25 mm freezing rain events. Therefore, solutions for 25 mm events are also relevant to mitigating heavy freezing rain events of ~ 60 mm.

6. High temperature (+35°C,+ 40°C, average temperature > 30°C, heat wave, high nighttime temperatures) / municipal stations

Further action recommended. High temperature and combinations of high temperature, high average temperature, high nighttime temperature and high load demand will have consequences on the capacity of the power transformers and cables.

6.2 Underground and Overhead Feeders

7. High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime / underground feeders

Further action recommended. Toronto Hydro replaces cables based on asset life replacement cycles or premature failures. However, it is projected that climate change related high temperatures could create higher demand for cooling, and may place greater stress on cables and lead to increasing occurrences of cable failures. Therefore, high heat impacts on cable was deemed to be a vulnerability.

8. Extreme rainfall / underground feeders

a. Feeders: Water treeing of the cables, flooding

Further action recommended. Climate change related stresses (i.e. higher temperature, higher loading, flooding from extreme rainfall) will continue to stress underground cables and constitute a vulnerability for Toronto Hydro.

b. Non-submersible equipment failure in vault type stations below ground in the Horseshoe Area (Former Toronto has a high risk result)

Further action recommended. While Toronto Hydro is gradually replacing vault type non-submersible equipment with submersible versions, non-submersible vault type equipment is likely to remain in the system over the study period.

c. Above ground vault stations, access to the vault station and to the station equipment could be limited due to localized flooding of streets around the vault station, or at the station itself

No further action required. This impact does not relate to station load or capacity. The consequence is that the access to the vault stations or the stations equipment could be temporarily impeded. Impact is localized and temporary, and was not judged to warrant further action beyond current practices.

d. Network feeders: old N/W protectors are not submersible

Further action recommended. The old N/W protector may not operate properly if flooded. However, failure of the N/W protector will not automatically result in an interruption to the customer, since network systems are highly redundant. Toronto Hydro is installing new N/W protectors that are submersible, but there may still be older non-submersible N/W protectors in the systems, particularly in downtown over the study period. Further study could be undertaken to evaluate the cost of replacing old network protectors prior to the end of their expected lifecycle against the frequency and consequence of old N/W protectors being flooded.

9. High winds (120 km/h) / padmount stations on distribution network (Former Toronto)

No further action required. The damaged equipment will result in an overall or some loss of service capacity and function. However, it is judged that flying debris is too much of a random occurrence to warrant further action.

10. High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave / Overhead power lines (radial and loop)

Further action recommended. Higher temperatures will have impacts on the overall capacity of the power lines. In the downtown area, there are critical, constrained areas (i.e. built up zones) where added conductor/transformer capacity may be difficult to implement.

11. High nighttime temperatures / Overhead power lines (radial)

No further action required. Night time temperatures with minimum ≥ 23°C in and of itself is not a significant concern for Toronto Hydro in terms of electrical service provision as peak demand has subsided. However, it is important to note that high daily temperatures in combination with high night time temperatures are a concern. This has been considered under different climate-infrastructure interaction, average temperature over 30°C on a 24 h basis, so this particular interaction does not warrant further action.

12. Freezing rain - ice Storm 15 mm and high winds 70 km/h / Overhead feeders in loop configuration

Further action recommended. The risk assessment of radial systems resulted in a high risk rating for this interaction. In overhead loop systems, it was hypothesized that their more redundant configuration would reduce customer interruptions, affect fewer clients or cause outages of shorter durations, thus yielding a high-medium risk rating of 35. However, the frequency of freezing rain events are projected to increase slightly by the end of the study horizon compared to present day (see table 3-2). The tree canopy may also be weakened by increased disease threats. Finally, freezing rain events tend to be widespread, and there is no reason to believe that both branches of an overhead loop circuit might not be equally susceptible to damage. For all of these reasons, all overhead power lines, irrespective of electrical configuration, were deemed as vulnerable.

13. Freezing rain/ice storm 60 mm ≈ 30 mm radial (major outages) / overhead lines (radial and loop)

Further action recommended. See explanation for freezing rain and stations (item 5 above).

14. Lightning / overhead power lines (radial and open loop) and SCADA system

Further action recommended. It is difficult to predict the increase of lightning strikes for the study period; however it is interesting to note that the probability of a lightning strike in an area of 0,015 km^2 anywhere within the City of Toronto is very high for the study period. At the moment, lightning strike intensity, the number of lightning arrestors/km and arrestor performance are not monitored by Toronto Hydro. Given this uncertainty, and since lightning strikes are currently a frequent source of outages, lightning strikes were judged to be a continued vulnerability.

15. Snow > 5 cm and snow > 10 cm / overhead power lines (radial)

No further action required. The number of snow days is highly variable. The trend seems to be decreasing, but snow days will still occur annually. During the workshop, Toronto Hydro mentioned having problems regarding insulator tracking leading to pole fires especially at higher voltages (13.8 kV and 27.6 kV) and switch failures. However, Toronto Hydro is already monitoring and dealing with this issue.

6.3 Civil Structures

16. Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 6hrs+ (combination of events) / civil structures: underground feeders (Former Toronto)

Further action recommended. Vaults and chambers already suffering from degradation issues will deteriorate more rapidly over time. From THESL (Toronto Hydro, 2014a): *As below-grade structures age, the greatest concern becomes structural strength. Structural deficiencies affecting vaults include degradation of concrete and corrosion of supports such as beams and rebar. Once degradation and corrosion sets in, conditions can deteriorate rapidly and in many cases from one season to the next. Of particular concern is the winter season when moisture and water enter in below*-grade *structures, freezes and thaws, and carries with it salt that has been used at grade to melt ice and snow.*

While maintenance can reduce the rate of deterioration, incidence of extreme rainfall, snowfall, freezing rain and the application of road salt will persist throughout the study period and continue to contribute to the premature aging of civil structures. While, it could not be determined in the study whether premature aging of civil structures will be exacerbated by a changing climate, this issue will persist over the study period and is therefore judged as an on-going vulnerability

17. Snow > 5 cm and snow > 10 cm / civil structures: underground feeders (Former Toronto)

No further action required, but combinations of climates events require additional study. As days with snow will probably decrease, the snow days alone were not judge to be a significant vulnerability. However, snow days will still occur over the study period, and in combination with extreme rainfall, freezes and thaw, freezing rain, and the continued application of road salt, premature degradation of civil structures was judged to be an ongoing vulnerability for Toronto Hydro.

18. Frost / civil structures (overhead and underground feeders)

Further action recommended. While the threat of frost is decreasing over the study period, it is noted that frost penetration will still occur with occasional extreme cold weather. Since Toronto Hydro already experiences problems with frost and its civil infrastructure, frost impacts are judged to be a vulnerability.

6.4 Human Resources

19. All climate parameters / human Resources

Further action recommended. While occupational health and safety procedures will continue to be in place in the future, human resources will continue to be vulnerable to climate change related weather events due to the need to travel, access, and work on equipment in spite of the weather.

7 Conclusions

The Phase 2 study presents a climate change based vulnerability assessment of electrical distribution infrastructure. It seeks to inform future investigations, planning and investment decisions on system and component vulnerabilities, and to support efforts to enhance the resilience of the electrical system. This chapter presents Step 5 of the Protocol and covers electrical distribution system vulnerabilities within the City of Toronto, adaptation options and areas of further study.

7.1 Vulnerabilities to a Changing Climate

The Phase 2 employed a high level risk based screening methodology to determine where infrastructure vulnerabilities to climate change may be present. All high risk infrastructure-climate parameter interactions, as well as medium risk interactions assessed as vulnerable through the engineering analysis comprise the vulnerabilities identified for Toronto Hydro's electrical distribution system to a changing climate. These vulnerabilities can be divided into five groups based on how climate parameters affect the system. The following paragraphs summarize these vulnerabilities, while table 7-1 provides more detailed information by infrastructure-climate parameter interactions.

High Ambient Temperatures – Station and Feeder Assets

High ambient temperatures create problems for the distribution system because of the compounding effect of high demand (e.g. for cooling) and high ambient temperature affecting equipment cooling and electrical transmission efficiency. Two specific climate parameters were of most significant concern, daily peak temperatures exceeding 40°C (excluding humidity) and daily average temperatures exceeding 30°C. In these cases, the climate analysis found that such extreme temperatures have occurred only rarely in the past, but are projected to occur on an almost semi-annual to annual basis by the 2030's and 2050's respectively. Through preliminary demand and supply growth projections completed for this study, these vulnerabilities were identified based on the notion that extreme heat will generate electrical demand for cooling in areas where station excess capacity is projected to be marginal. Furthermore, such temperature extremes may cause equipment, notably power transformers, to operate beyond their design specifications and increases the likelihood of failure. It is anticipated that vulnerability to high heat events will be concentrated in the Former Toronto area, although there are several horseshoe station service areas which would also be vulnerable.

Freezing Rain, Ice Storms, High Wind and Tornadoes – Overhead Station and Feeder Assets

Freezing rain, ice storms, high wind and tornado events cause immediate structural issues for overhead distribution assets, as they have the capacity to exceed the design limits of equipment and their supports. Outages may result from damage to equipment arising from direct forces applied by climate parameters (e.g. wind, weight of ice) or by other objects (e.g. tree branches, flying debris). These kinds of events affect outdoor station and feeder assets, which are largely concentrated in the horseshoe service area. It is important to emphasize that Toronto Hydro has experienced problems related to freezing rain, ice storms (up to 25 mm) and high winds (up to 90 km/h) in the past. These events are projected to continue in the future, but continue to occur on a less than annual or even decadal frequency. More severe ice storms (60 mm), high winds (over 120 km/h) and tornadoes (EF1+) have been extremely rare in the past, and while there is a lack of scientific consensus on projected future frequencies for these extreme events, they are likely to remain rare in the future. Nevertheless, the damages caused by these kinds of events can be severe. Therefore, they were judged as ongoing and future vulnerabilities for Toronto Hydro.

Extreme Rainfall – Underground Feeder Assets

Extreme rainfall events may potentially flood underground feeder assets, which are largely concentrated in the Former Toronto and northeastern horseshoe areas. Toronto Hydro is aware of these issues in relation to its assets and has programs to replace non-submersible equipment with submersible type equipment, to relocate equipment where possible. However, due to the large quantity of underground feeder assets across the city, replacement and reinforcement of underground assets will be a gradual and ongoing activity for Toronto Hydro over the study period. As such, some underground feeder assets may remain an area of vulnerability for Toronto Hydro.

Snowfall, Freezing Rain - Corrosion of Civil Structures

The degradation of civil structures (i.e. concrete and steel), which is accelerated by humidity and the presence of de-icing salts, was identified as a potential area of vulnerability to climate change. Corrosion is already an ongoing issue for Toronto Hydro and current assets have a design lifespan which accounts to a great extent for corrosion issues. However, it is not clear from this study whether the climate change stresses will exacerbate the problem. While snowfall days are generally expected to decrease with a warming climate, they will continue to occur annually through to the 2050's. As a result, and in combination with freezing rain events, the application of de-icing salts will also be applied annually through the study horizon. Nonetheless, it should be emphasized that corrosion represents a long-term and on-going vulnerability for Toronto Hydro.

Lightning – Overhead Feeder Assets

Based on workshop feedback and an examination of Toronto Hydro's ITIS outage data, Toronto Hydro recognizes that lightning impacts are a significant source of outages on the distribution system today. While there have been advances in predicting lightning activity, there was insufficient data available on lightning strike intensity and arrester performance to suggest how future lighting activity may affect the electrical system. For these reasons, this study suggests that lightning activity will continue to be an area of vulnerability.

7.2 Adaptation Options

Adaptation options are suggested for all the infrastructure-climate parameter interactions identified as vulnerabilities. The Protocol classifies adaptation options in four possible categories:

- remedial engineering actions which aim to strengthen or upgrade the infrastructure;
- management actions to account for changes in the infrastructure capacity;
- continued monitoring of performance of the infrastructure and impacts; and
- further study required to address gaps in data availability and data quality.

Adaptation options by infrastructure-climate parameter interaction are presented in Table 7-1.

Table 7-1 Vulnerabilities and Adaptation Options by Infrastructure Asset, Climate Parameter

Affected infrastructure	Climate Parameter	Adaptation Option	Details
Stations, Communications and Protection Systems			
1. Transmission stations, municipal stations, protection and control systems Critical component: batteries	High temperature above 25°C	Further study required	Toronto Hydro has experienced problems with station batteries failing short of expected lifespans (i.e. approximately 10 years). Operating batteries in rooms where the ambient temperatures increases above 25°C is a contributing factor to premature battery failure (Toronto Hydro, 2014c). As battery rooms are not temperature controlled, Toronto Hydro could monitor how ambient temperatures of rooms within stations housing batteries fluctuate during the warmer summer months and evaluate whether additional measures are needed (e.g. review of battery technical specifications, including aging factor) to reduce battery degradation.

Affected infrastructure	Climate Parameter	Adaptation Option	Details
2. Transmission stations, municipal stations Critical component: power transformers	High temperature above 35°C, 40°C Average daily temperature > 30°C Heat wave High nighttime temperatures	Further study required	Given the increased frequency of high heat conditions in the future, coupled with continued demand growth, infrastructure owners (Toronto Hydro and Hydro One), could conduct a could conduct a further study evaluating the technical and financial feasibility of installing transformers with a higher capacity, or installing more transformers at stations (shared load) where space permits. Another possibility is to evaluate the technical and financial feasibility of increasing the design standard for current power transformer equipment, for example, by designing to a daily average ambient temperature higher than 30 °C (35 °C) and maximum temperature with a higher temperature than 40°C (45 °C). Finally, these measures should be complemented by continued demand side management /energy conservation programs.
3. Transmission stations: only outdoor stations 4. Municipal stations: Horseshoe area outdoor stations Critical component: Overhead exit lines (for freezing rain and high winds parameters)	Freezing rain/ice storm : 25 mm, 60 mm High winds : 120 km/h and tornadoes	Management actions and further study required .	Major freezing rain, ice storm, high wind and tornado events are not expected to be an annual occurrence in the future, but will still likely occur over the study period. Station exit lines, either overhead ones or where underground cables surface, are a particular point of vulnerability, as downed exit lines can sever power supply to the entire service area. Toronto Hydro could monitor the frequency of damage to station exit lines and poles across a range of potential weather threats (freezing rain, high winds) to evaluate whether this critical portion of the distribution network requires strengthening. Toronto Hydro could also consider a station by station study of surroundings to identify areas around stations susceptible to generating flying debris (e.g. trees, buildings). Emphasis should also be placed on optimizing the emergency response and restoration procedures to reduce system down time. Note that Toronto Hydro is already undertaking a review and enhancement where necessary of response planning, dispatching operations, prioritization of restoration activities, coordination with other utilities, response team training and preparation.
Arresters (for lightning parameter)	Lightning	Monitoring activities	Lightning events and strikes are difficult to predict, but are likely to increase in frequency and intensity. However, lightning strike intensity and arrester performance is not currently monitored. Given the importance of lightning strikes as a cause of outages, it is recommended that the lightning activities (e.g. frequency, intensity), soil resistivity (i.e. decreased soil moisture from longer and hotter summers) and impacts on the system could be more closely monitored to provide more information regarding the risks of lightning strikes. For example, where high voltage arresters are installed, counters (if not already present) could also be installed to check if a particular phase or transmission line suffers from an exceptionally high number of overvoltages leading to arrester operation. Lightning strikes on the building housing stations could be investigated to determine whether they resulted in any overvoltage impacts. If further studies on lightning activity result in a better definition of lightning characteristics and impacts, or if monitoring indicates a higher rate of failure, a review of actual design practices could be undertaken.

Affected infrastructure	Climate Parameter	Adaptation Option	Details
Feeders, Communication and Protection Systems			
5. Underground feeders Critical component: cables and power transformers	High temperature above 35°C, 40°C Average daily temperature > 30°C Heat wave High nighttime temperatures	Monitoring activities	For power transformers, see discussion above on station power transformers (see row 2). For cables, increased temperature operation tends to reduce the dielectric strength of the cables. Toronto Hydro is currently trialing cable diagnostic testing techniques as a method of detecting vulnerabilities in cables. If cable testing techniques prove reliable in detecting potential failures, Toronto Hydro could consider extending diagnostic techniques to all cables to monitor heat stress impacts on cables to evaluate whether high design standards or more frequent replacement is required.
6. Underground feeders : Submersible type Critical component: cables	Extreme rainfall: 100 mm <1 day + antecedent	Monitoring activities	The presence of water can lead to an electrical failure of the cables (water treeing) and/or reduce the dielectric strength of cables. Cable diagnostic testing can be employed to monitor the degradation of underground cables. This study also supports Toronto Hydro's program to replace and renew older cable assets with moisture and tree resistant underground conductors such as TRXLPE cables. The development of flood risk mapping, coupled with historical registry of flood related equipment failures could enhance the identification of areas for priority intervention.
7. Underground feeders: Vault type – Below ground Critical component: non-submersible equipment	Extreme rainfall: 100 mm <1 day + antecedent	Remedial engineering actions	Toronto Hydro is currently upgrading non-submersible equipment located in below grade vaults with submersible equipment, or relocating them above grade. The development of flood risk mapping, coupled with historical registry of flood related equipment failures could enhance the identification of areas for priority intervention.
8. Underground feeders: 13.8 kV Network systems	Extreme rainfall: 100 mm <1 day + antecedent	Remedial engineering actions	Many old network protectors are not submersible, particularly in the downtown area. The current Toronto Hydro standard is to use submersible network protectors when replacing old equipment. Further study could be undertaken to evaluate the benefit and cost of replacing old network protectors prior to their end of life versus replacement at their end of life (i.e. potential for flood damage and outages prior to replacement).
9. Overhead feeders (Radial and loop) Critical component: power transformers and conductors	High temperature above 35°C High temperature maximum above 40°C Average daily temperature > 30°C Heat wave	Monitoring activities	Climate change is projected to increase the frequency of high heat conditions in the future. Coupled with continued demand growth, this is projected to increase heat stresses on overhead distribution feeder assets. However, unlike the case with station transformers, where projected heat and capacity reveal a clear vulnerability in terms of supply capacity, it is not clear whether high temperatures will have the same impact across the distribution feeder system (i.e. are there bottlenecks to supplying electricity during periods of high heat at certain stations or across the grid?). Toronto Hydro should continue to monitor key grid operational indicators for distribution transformers, such as load currents, billing data, transformer oil and ambient temperatures. This information can be used to help evaluate whether distribution line capacities are sufficient to handle increased electrical loads.
10. Overhead feeders (Radial and loop) Critical component: conductors	Freezing Rain/Ice storm: 15 mm and high winds 70 km/h	Management actions and remedial engineering actions	Toronto Hydro is already experiencing outages caused by tree contacts and is planning to increase its vegetation management activities. This study supports the need for increased tree trimming practices around overhead power lines and use of tree proof conductors in areas where outages due to tree contacts have been frequent.
11. Overhead : Radial and Loop Critical component: poles	Freezing rain/ice storm: 25 mm High winds: 90 km/h and 120 km/h, tornadoes	Management actions and further study required	See recommendations for stations above on freezing rain and tornadoes (see row 3).

Affected infrastructure	Climate Parameter	Adaptation Option	Details
12. Overhead power lines (radial and open loop) and SCADA system	Lightning	Monitoring activities	See recommendations for stations above on lighting (see row 3).
		Civil structures	
13. Civil structures: Underground feeders (Former Toronto)	Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 60 mm (combination of events)	Further study required	While maintenance can mitigate the risks of civil structures deterioration, changing climate conditions (e.g. freezing rain, rainfall, freeze-thaw) may exacerbate premature degradation issues. However, it could not be determined in this study whether current design standards are sufficient to withstand future climate - salt and moisture related degradation. Further study could be undertaken to estimate salt/moisture corrosion effects in relation to climate change.
14. Civil structures: transmission and municipal stations, underground feeders	Frost	Further study required	The nature of the frost heave impacts to civil structures was not sufficiently evaluated within this study. Further study can be undertaken to identify whether there are any specific location, ground condition and structure combinations which contribute to frost heave impacts.
		Human Resources	
15. Human Resources	Heat, freezing rain, wind and tornadoes	Management actions	Toronto Hydro applies an occupational health and safety manual. Toronto Hydro is already conducting a review of its procedures in light of future extreme events to determine whether modifications in procedure or training are needed.

7.3 Other Areas of Study

Additional climate and infrastructure related areas of further study that can be used to enhance the understanding of electrical system vulnerabilities to climate change are listed below.

Climate

- Increase monitoring of important climate parameters across the city. For both the climate assessments and forensic analyses, a lack of observational data made understanding climate risk challenging and introduced uncertainties, particularly for specific climate parameters such as wind gusts, hourly rainfall measurements, and freezing precipitation accumulations. New monitoring would provide important benefits, including:
  - Addressing gaps in historical data;
  - Facilitating comparisons between sites across the city;
  - Improving the spatial resolution of the climate monitoring network, increasing the likelihood of capturing important meteorological events; and,
  - Providing additional data to assist in detecting new and emerging trends sooner than would be possible using the current network.
- Enhance details about weather impacts contained in the ITIS database. Although information contained within the database was extremely useful and yielded important insights, there were still gaps in the details of weather related outages which limited the evaluation of impacts;
- Refine and expand forensic investigations (see **Appendix C**) completed in this Phase 2 study. Several climate parameters, individual climate events and impacts were not investigated thoroughly due to the scope of the present study. In particular, further analyses could be done on:
  - Lake modified air and lake breeze influences on atmospheric hazards, especially extreme temperatures, ice accretion events, and severe thunderstorms (including extreme rainfall, downbursts/microbursts, and tornadoes);
  - December 2013 ice storm and other ice accretion events, particularly to help refine understanding of apparent variations in impacts between different sections of the city.

  - Temperature gradients across the city during periods of extreme heat. For example, why do some days show greater temperature gradients across the city than others, and what impact does this have on the system?
- Monitor and study the complex interaction between changes in tree growth, pest and disease conditions and resultant changes in risk to overhead systems. This could include investigating
  - The extent to which accelerated tree growth affects tree strength, and specifically resistance to wind and ice accretion loading;
  - Emerging and/or worsening tree pest and disease conditions which could reasonably be expected within the City of Toronto in the coming decades, and what potential changes in risk these will pose to overhead systems.

Infrastructure

- Site specific electrical configuration and area characteristics were not collected due to the scope of this study and scale of infrastructure system being analyzed (e.g. land use changes, high rise and condo development, population growth, terrain elevation, sewers, storm sewers, roads, tree canopy and tree type, buildings). Specific site characteristics, equipment age, or unique or uncommon equipment can alter sensitivity and vulnerabilities. Further study approaches could adopt a smaller spatial scale (e.g. station service areas, neighbourhoods) to reduce these scope and level of effort challenges and identify more site specific vulnerabilities;
- The scope of study and level of effort did not permit a detailed analysis of system performance and outage management (i.e. simulations of power rerouting or contingencies under different outage scenarios to various parts of the system). Further study approaches could adopt a smaller spatial scale (e.g. station service areas, neighbourhoods) to reduce these scope and level of effort challenges and permit a more detailed study and understanding of system performance and outage management;
- Smart Grid Data: Toronto Hydro has recently begun collecting information about outages from its grid based on smart grid feedback. Data history was short and not reviewed in this analysis. Further study examining smart grid data can be used to identify problem areas due to high load demand.

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Appendix A
Workshop Presentations

Appendix B
Background Information on Developing Climate Data

Appendix C
Forensic Analysis of Weather Related Power Outage Events

Appendix D
Risk Assessment Matrix

Appendix E
Risk Maps

Appendix F
Load Projection Methodology – Toronto Hydro

Appendix G
Engineering Analysis

Appendix H
PIEVC Worksheets

AECOM
85 Sainte-Catherine Street West
Montréal, Québec, Canada H2X 3P4
T 514 287 8500
F 514 287 8600
www.aecom.com

Environment

Clean Air Partnership
75 Elizabeth Street
Toronto, Ontario
M5G 1P4

Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

Application of the Public Infrastructure Engineering Vulnerability Assessment Protocol to Electrical Distribution Infrastructure

Final Report Appendices - Public

6031-8907

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Appendix A
Workshop Presentations

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Appendix B
Background Information on Developing Climate Data

Appendix B: Background Information for Developing Climate Data

B.1 Introduction

The following Appendix provides additional details about the methods used to develop the climate data used in the Toronto Hydro PIEVC Climate Change Risk Assessment. The development of climate data to support this study involved three main activities.

- Identify climate parameters (e.g. temperature, precipitation, wind) and threshold values at which infrastructure performance would be affected (i.e. climate hazards);
- Project the probability of occurrence of climate hazards for future climate; and,
- Convert projected probability of occurrence of future climate parameters into the seven point scoring scale employed by PIEVC studies to support the risk assessment.

This appendix provides more detailed information about the first two activities, namely the identification of relevant climate hazards and the estimation of their probability of occurrence in the future. The conversion of this probability information into PIEVC scores is not covered here, as it is already explained in the PIEVC Protocol V. 10.

B.2 Identification of Climate Parameters and Infrastructure Thresholds

In this study, the identification of relevant climate parameters and infrastructure impact thresholds (i.e. climate hazards) involved a combination of the three methods:

- Literature review;
- Practitioner consultation; and,
- Forensic analyses.

B.2.1 Literature Review

Design values in codes and standards generally provide an excellent “first guess” to determine infrastructure impact thresholds, providing information on not only baseline climatic design values, but on safety factors, load combinations, and so on. Codes and standards can also provide an understanding of changing thresholds depending on the age of infrastructure and therefore applicable code or standard. These values can also be used as a basis for discussion with practitioners, to determine if there are local modifications for in-field infrastructure. The occasional review and updating of codes and standards also tends to generate discussion and papers in the published literature, which can further provide background on why changes were made, how climatic data was processed, and when these changes became effective.

B.2.2 Practitioner Consultation

Discussion and consultation with practitioners is invaluable. Practitioners can describe important historical events and their impacts, relevant logistical and operational elements of the system, and new and emerging problems which may not be documented elsewhere. More generally, practitioners can provide guidance on where problematic interactions tend to arise and what can be done to reduce those impacts (i.e. adaptation measures).

This project included two workshops in which assumptions regarding climate elements and infrastructure breakdown were evaluated, discussed and modified. The first workshop played a significant role in re-evaluating climate elements which had been identified under Phase I. For example, in light of recent severe weather events **(see Appendix C)**, extreme rainfall and freezing rain were given somewhat higher priority under Phase II. Following a preliminary climate analysis, several thresholds were removed, modified, or refined at the second workshop, and the discussion of complex interactions confirmed findings from the forensic.

B.2.3 Forensic Analyses

Forensic analysis is the evaluation of past events through the application of scientific techniques and understanding to establish facts. It is meant to diagnose the causes of, and contributing factors to, a given infrastructure failure incident. These analyses can be used to refine our understanding of not only what caused a given failure, but also how to prevent or reduce the risks of similar failures in the future. In the context of extreme weather, we can evaluate the meteorological conditions associated with an incident and compare those to impacts produced (i.e. what was damaged, how was it damaged, etc.) and the supposed design capacity of that system (i.e. what was it designed for, do field conditions match design requirements).

Forensic analysis first requires the identification of important historical climatic events. In this case this was provided by Toronto Hydro's ITIS database, and further augmented by newspaper and press release searches. These events were then compared to all available observational data, including both Environment Canada's climate network and as well as data provided by TRCA (TRCA 2014) for several specific events. A full report containing analyses of several different events in the GTA is provided in **Appendix C**. These results were then compared to the literature and were also presented to practitioners for further scrutiny. Findings included the apparent impact of tree canopies on wind resistance of trees (resulting in subsequent secondary impacts on overhead systems), as well as regional differences in impacts from freezing rain, likely the result of a combination of local meteorological conditions (temperature regimes) and regional differences in canopy cover and tree health.

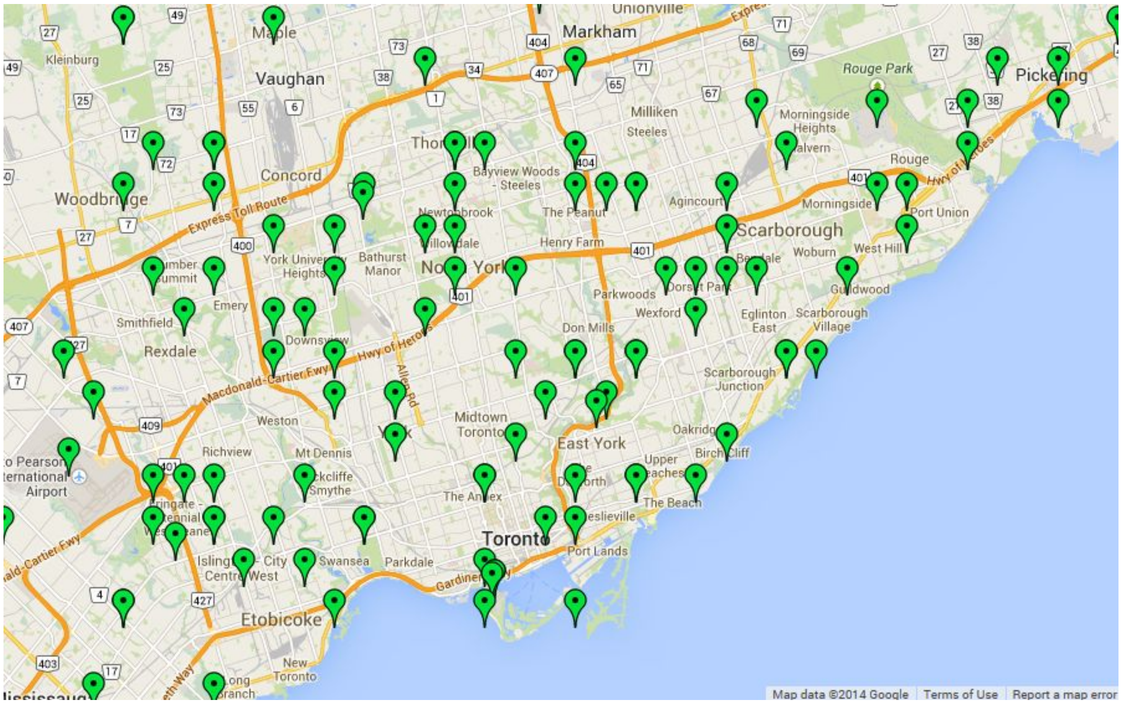
B.3 Establishing the Probability of Occurrence of Climate Hazards

The following section provides information necessary to project the future probability of occurrence of climate hazards. Information about the development of a historical climate baseline, the sourcing and use of future climate projection data, and the treatment of complex variables is presented.

B.3.1 Historical Climate Observations

Environment Canada is the authoritative source of climate information in Canada. In the Toronto region many observations stations have been in place and subsequently closed (see **Figure B.1**). In most cases stations only have observations for a few years – too short to establish a 'climatology'. The most recent normals period established by the World Meteorological Organization (WMO) was 1981-2010. Although 30 years is the accepted minimum, Environment Canada has calculated normals for stations which have at least 10 years of data within this period.

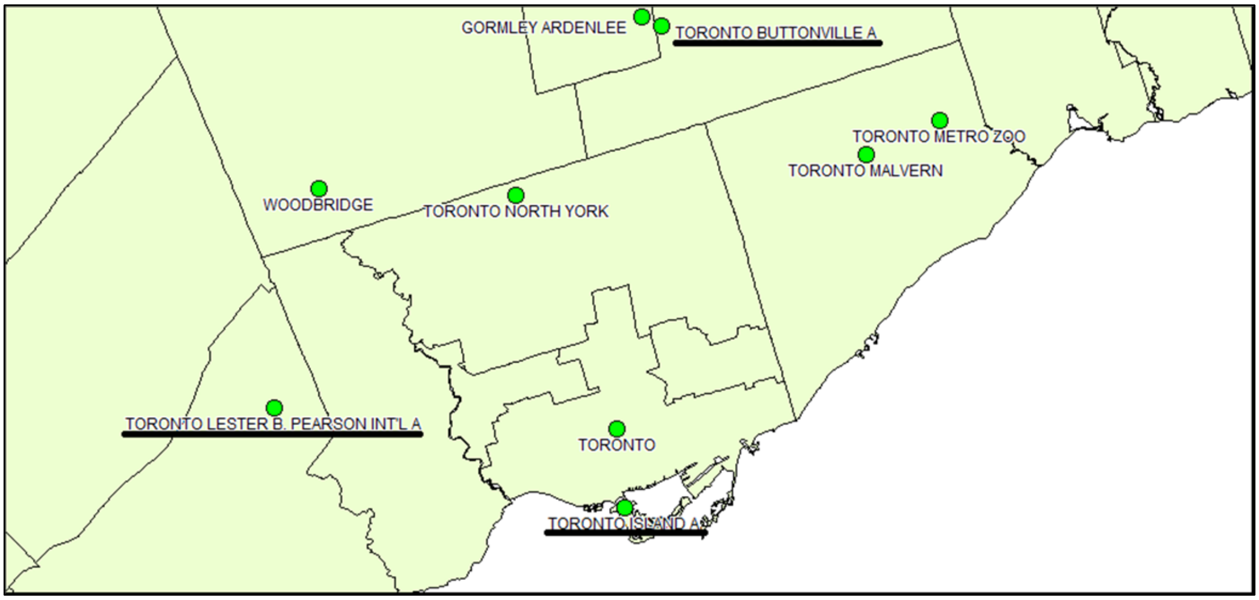
Figure B.1 All Historical Environment Canada Stations



Note: includes those not currently open

To establish reliable statistics on the frequency of events, long term records are preferred and with this area, there are some stations available. It is generally accepted that to establish a 'normal' climate, a minimum of 30 years of data as required. This supposedly ensures that short term natural variability is averaged out. Detailed hourly observations are usually only available at airport locations such as Toronto Pearson, Buttonville and Toronto Island. These airport locations are also typically the only source of variables other than temperature and precipitation (such as wind or weather observations). Of these, Toronto Pearson has the lengthiest reliable data record. Those regional stations for which normals data was calculated for 1981-2010 are shown in **Figure B.2**.

Figure B.2 Environment Canada 1981-2010 Normals Locations



Note: Stations with additional weather and wind data are underlined.

B.3.2 Future Projections

B.3.2.1 Global Climate Models

These variables will consider both the historical period frequencies observed in the region and the corresponding projections used in the most recent Intergovernmental Panel on Climate Change (IPCC)'s Fifth Assessment Report (AR5). The suite of models used in AR5 is from the Fifth Coupled Model Intercomparison Project (CMIP5), coordinated by the World Climate Research Program, and was retrieved from the following data portal:

http://cmip-pcmdi.llnl.gov/cmip5/guide_to_cmip5.html.

Since the second IPCC Assessment released in 1995, the number of contributing international climate modelling centres, models, and their complexity, have increased significantly – from 11 models to the current 40. With increased computing power, better refinement of atmospheric phenomena have been incorporated, and model spatial and temporal resolution has improved (Kharin et al. 2013). An important outcome of this increase in model availability is the ability to produce projections of future climate based upon an 'ensemble' of many models versus the use of single or only a few models. In this report, all available AR5 model runs (many models have more than a single projection available) were used. The use of multiple models to generate a 'best estimate' of climate change is preferred over a single model outcome. Research has indicated that the use of multi-model ensembles is preferable to the selection of a single or few individual models since each model can contain inherent biases and weaknesses (IPCC-TGICA, 2007, Tebaldi and Knutti, 2007). The use of the ensemble projection from the family of global modelling centers is likely the most reliable estimate of climate change projections on a large scale (Gleckler et al, 2008).

A full list of the climate models and their country of origin is presented in **Table B.1**.

Table B.1 List of CMIP5 Global Climate Models (GCMs) Used for this Study

Model Name	Organization	Country	Organization Details
ACCESS1-0	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
ACCESS1-3	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
BCC-CSM1-1	BCC	China	Beijing Climate Center, China Meteorological Administration
BCC-CSM1-1-M	BCC	China	Beijing Climate Center, China Meteorological Administration
BNU-ESM	GCESS	China	College of Global Change and Earth System Science, Beijing Normal University
CanESM2	CCCma	Canada	Canadian Centre for Climate Modelling and Analysis
CCSM4	NCAR	US	National Center for Atmospheric Research
CESM1-BGC	NSF-DOE-NCAR	US	National Science Foundation, Department of Energy, National Center for Atmospheric Research
CESM1-CAM5	NSF-DOE-NCAR	US	National Science Foundation, Department of Energy, National Center for Atmospheric Research
CMCC-CESM	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CMCC-CM	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CMCC-CMS	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CNRM-CM5	CNRM-CERFACS	France	Centre National de Recherches Meteorologiques / Centre Europeen de Recherche et Formation Avancees en Calcul Scientifique
CSIRO-Mk3-6-0	CSIRO-QCCCE	Australia	Commonwealth Scientific and Industrial Research Organisation in collaboration with the Queensland Climate Change Centre of Excellence
FGOALS-g2	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences
FGOALS-s2	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences
FIO-ESM	FIO	China	The First Institute of Oceanography, SOA, China
GFDL-CM3	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GFDL-ESM2G	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GFDL-ESM2M	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GISS-E2-H	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-H-CC	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-R	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-R-CC	NASA GISS	US	NASA Goddard Institute for Space Studies
HadCM3	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-AO	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-CC	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-ES	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
INMCM4	INM	Russia	Institute for Numerical Mathematics
IPSL-CM5A-LR	IPSL	France	Institut Pierre-Simon Laplace
IPSL-CM5A-MR	IPSL	France	Institut Pierre-Simon Laplace
IPSL-CM5B-LR	IPSL	France	Institut Pierre-Simon Laplace
MIROC-ESM	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere

Model Name	Organization	Country	Organization Details
			and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies
MIROC-ESM-CHEM	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies
MIROC4h	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MIROC5	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MPI-ESM-LR	MPI-M	Germany	Max Planck Institute for Meteorology (MPI-M)
MPI-ESM-MR	MPI-M	Germany	Max Planck Institute for Meteorology (MPI-M)
MRI-CGCM3	MRI	Japan	Meteorological Research Institute
NorESM1-M	NCC	Norway	Norwegian Climate Centre
NorESM1-ME	NCC	Norway	Norwegian Climate Centre

B.3.2.2 Representative Concentration Pathways

A new initiative in the IPCC AR5 is the introduction of RCPs (Representative Concentration Pathways; see **Figures B.3** and **B.4**). They represent a range of possible projection outcomes which depend upon different degrees of atmospheric warming. The lowest RCP 2.6, represents an increase of 2.6 W/m^2 to the system, while the highest RCP 8.5 represents an increase of 8.5 W/m^2 of energy. This range encompasses the best estimate of what is possible under a small perturbation situation (2.6) and under a large increase in warming (8.5). It is unknown which of the RCPs will apply in the future.   However, it is important to note that historically, the GHG emissions have followed the highest (8.5) pathway. In the absence of a global agreement on GHG reduction, this trend is expected to continue which would support this pathway going forward. Nevertheless, in this report, 4.5 (moderate) and 8.5 (high) projected change are presented. The number of models used for the ensemble varies with the RCP selected since not all international modelling centres generated model runs for all RCPs.

Figure B.3 Representative Concentration Pathways used for AR5

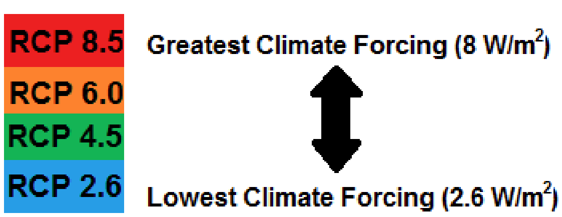
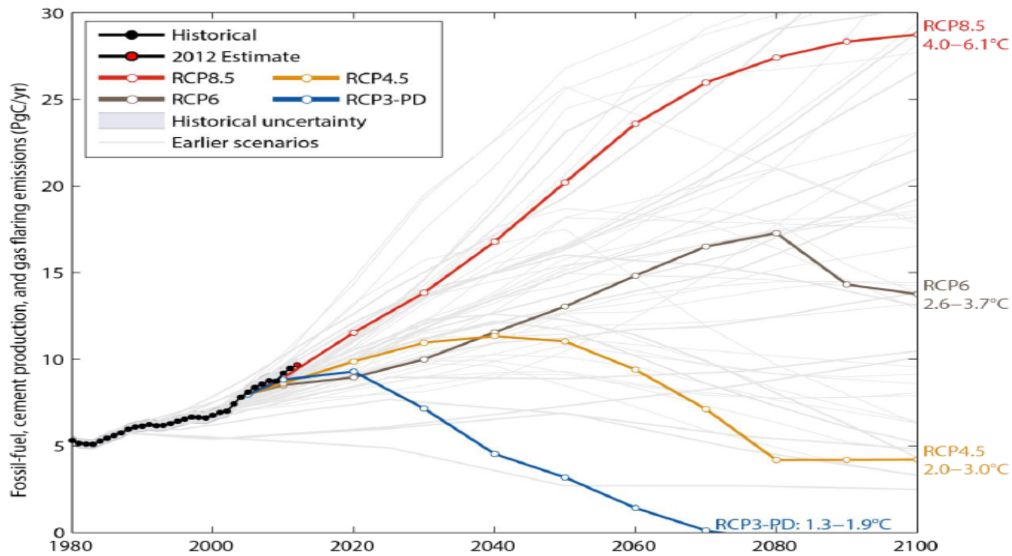


Figure B.4 Global GHG Emissions and their Relationship with Representative Concentration Pathway Assumptions



Source: Peters et al. 2012a

Factors influencing the RCP include population growth, economic growth, degree of urbanization, land use change, use of green versus carbon-based energy sources and any future international agreements on greenhouse gas (GHG) emissions, among others.

B.3.2.3 Important IPCC Findings

The full IPCC AR5 Working Group 1 Report was released in September 2013 and provides general details of the IPCC position on climate change. It can be found here: http://www.ipcc.ch/report/ar5/wg1/

Some of the main findings of this report are summarized in the Summary for Policymakers and are reproduced below:

- Warming of the climate system is **unequivocal**, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, sea level has risen, and the concentrations of greenhouse gases have increased.

- Each of the last three decades has been successively warmer at the Earth's surface than any preceding decade since 1850.

- Over the last two decades, the Greenland and Antarctic ice sheets have been losing mass, glaciers have continued to shrink almost worldwide, and Arctic sea ice and Northern Hemisphere spring snow cover have continued to decrease in extent.

- The atmospheric concentrations of carbon dioxide (CO2), methane, and nitrous oxide have increased to levels unprecedented in at least the last 800,000 years.

- Human influence on the climate system is clear. This is evident from the increasing greenhouse gas concentrations in the atmosphere, positive radiative forcing, observed warming, and understanding of the climate system.

- Human influence has been detected in warming of the atmosphere and the ocean, in changes in the global water cycle, in reductions in snow and ice, in global mean sea level rise, and in changes in some climate extremes. This evidence for human influence has grown since AR4. It is *extremely likely* that human influence has been the dominant cause of the observed warming since the mid-20th century.

- Observational and model studies of temperature change, climate feedbacks and changes in the Earth's energy budget together provide confidence in the magnitude of global warming in response to past and future forcing.

- Climate models have improved since the AR4. Models reproduce observed continental-scale surface temperature patterns and trends over many decades, including more rapid warming since the mid-20th century and cooling immediately following large volcanic eruptions.

- Global surface temperature change for the end of the 21st century is *likely* to exceed 1.5°C relative to 1850 to 1900 for all RCP scenarios except RCP2.6. It is *likely* to exceed 2°C for RCP6.0 and RCP8.5, and *more likely than not* to exceed 2°C for RCP4.5. Warming will continue beyond 2100 under all RCP scenarios except RCP2.6. Warming will continue to exhibit interannual-to-decadal variability and will not be regionally uniform.

- Changes in the global water cycle in response to the warming over the 21st century will not be uniform. The contrast in precipitation between wet and dry regions and between wet and dry seasons will increase, although there may be regional exceptions.

- Continued emissions of greenhouse gases will cause further warming and changes in all components of the climate system. Limiting climate change will require substantial and sustained reductions of greenhouse gas emissions.

With each subsequent report, the evidence of climate change builds and increasingly points towards greater confidence that human-kind is having and will continue to influence our future climate, from warming, to extreme events, to sea-level rise to melting sea-ice. Among the most recent IPCC reports was the addition of a separate document on climate extremes, the IPCC SREX document (SREX-IPCC, 2012). So in addition to changes in the mean climate, extreme climate events will also be impacted, and in many cases the changes in the extremes are expected to be greater than mean changes.

Of particular interest are some conclusions from the extremes report (SREX-IPCC, 2012):

- It is *virtually certain* that increases in the frequency and magnitude of warm daily temperature extremes and decreases in cold extremes will occur in the 21st century at the global scale.

- It is *very likely* that the length, frequency, and/or intensity of warm spells or heat waves will increase over most land areas

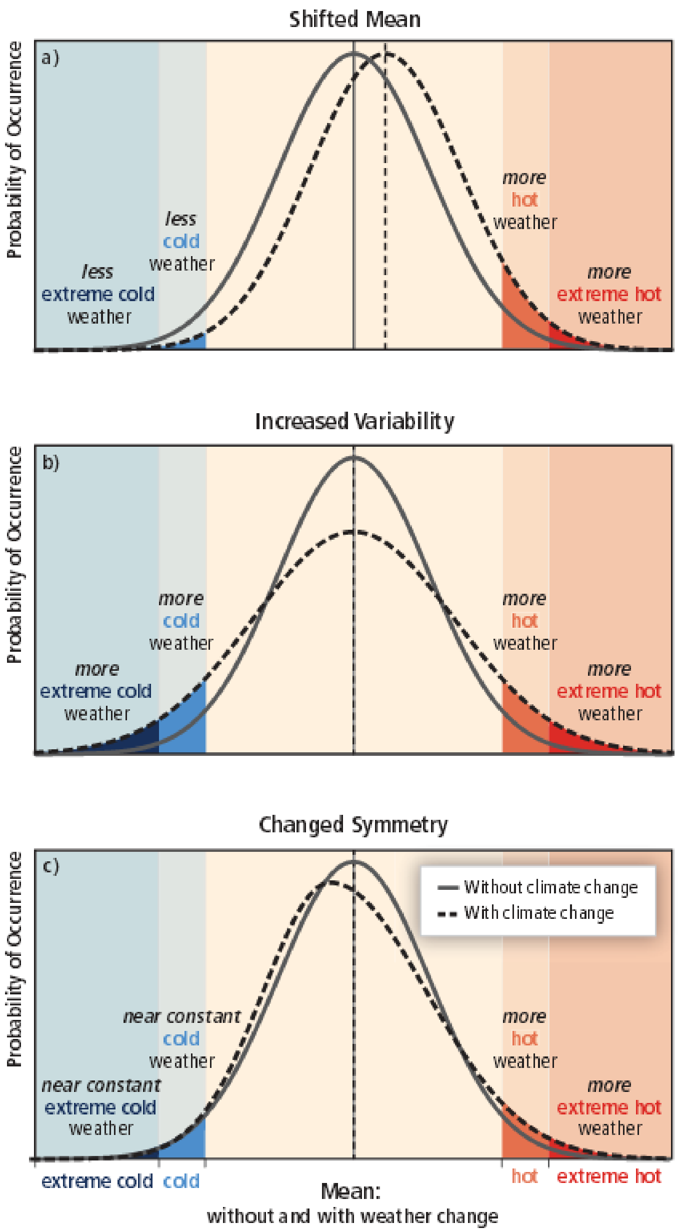
- It is likely that the frequency of heavy precipitation or the proportion of total rainfall from heavy falls will increase in the 21st century over many areas of the globe

- Extreme events will have greater impacts on sectors with closer links to climate, such as water, agriculture and food security, forestry, health, and tourism

- Attribution of single extreme events to anthropogenic climate change is challenging

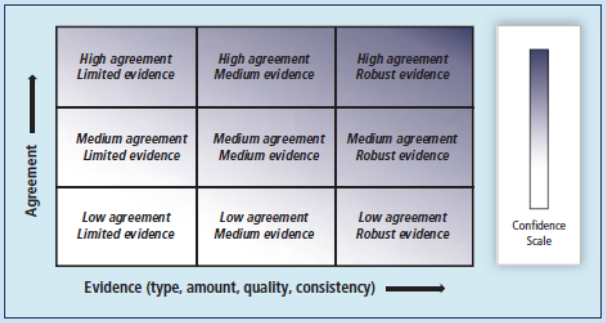
An example from the report is shown below for changes in temperature, which demonstrate how greater likelihood of extremes is possible through changes in mean, variability and symmetry.

Figure B.5 How Changes in Temperature Distributions can affect Extremes (IPCC, 2012)



Confidence wording in the IPCC documents are characterized by the use of specific terms such as 'very likely' or 'virtually certain', where in previous reports changes may have been referred to as 'likely'. There has been a gradual increase in confidence of the projections from climate models over time. A summary of the confidence terminology used in the official reports is shown below (SREX-IPCC, 2012):

Figure B.6 IPCC Confidence Terminology



A depiction of evidence and agreement statements and their relationship to confidence. Confidence increases toward the top-right corner as suggested by the increasing strength of shading. Generally, evidence is most robust when there are multiple, consistent independent lines of high-quality evidence.

The following terms indicate the assessed likelihood:

Term*	Likelihood of the Outcome
Virtually certain	99–100% probability
Very likely	90–100% probability
Likely	66–100% probability
About as likely as not	33–66% probability
Unlikely	0–33% probability
Very unlikely	0–10% probability
Exceptionally unlikely	0–1% probability

* Additional terms that were used in limited circumstances in the Fourth Assessment Report (*extremely likely:* 95–100% probability, *more likely than not:* >50–100% probability, and *extremely unlikely:* 0–5% probability) may also be used when appropriate.

With each report there are more and higher quality observations of the changing climate and improvements in the models equations/parameterizations, and their spatial and temporal detail. The IPCC reports continue to provide the best science-based information on projected climate change assembled from the best climate researchers worldwide. Climate change projections for this report are based upon the same new models used for guidance in the IPCC AR5 report recently released.

B.3.3 Climate Projection Methodology

B.3.3.1 The Delta-Method Applied to the Ensemble

The use of the CMIP5 ensemble not only allows for the calculation of an average projection of future climate which represents the consensus of all independent models, but it also allows for the estimation of projection uncertainty and statistical distributions which could not be determined from a single model. The projections for the variables in this report represent the 'best estimate' available – and are more indicative of the general expectations of climate change over any single model.

The ability of the CMIP5 ensemble to reproduce the historical temperature gives us confidence that the newest models used in this report are reliable and when grouped can provide accurate estimates. This would imply that reliable historical climatology should lead to reliable future projections.

This study uses a so-called 'delta' approach (sometimes also called 'climate change factor approach'), to obtain future estimates of climate variables. It is generally comprised of the following tasks.

1. Obtain a baseline climate condition (or 'average' climate).

2. Using an ensemble of all available CMIP5 models ('CMIP5 ensemble'), we obtain the model average climate for this same period – the average of all models for the grid covering Peel region. However, each modeling center does not use the same grid alignment and resolution, so a first step before obtaining the average of all the models is to regrid them all to a common resolution. This regridding typically uses a scale representative of the resolution of the models, in this case approximately 200 by 200 km.

3. The CMIP5 ensemble future climate is obtained for this same cell for each of the required future periods. In this case, every 10 years starting in the year 2011 and ending in the year 2100. From this we will have average future conditions of all the models for ten 10 year periods.

4. The difference (or 'delta') between the CMIP5 baseline and CMIP5 future periods are obtained – this represents the change in climate condition. Ten climate deltas are produced, for example, the delta between the baseline (1981-2010) and the 2051-2060 period is one of the deltas.

5. The final step is to then apply this delta value to the baseline period.

B.3.3.2 Complex Climate Events: Regional Climate Models and other projection techniques

The delta method applied to an ensemble of GCMs is not the only method available for climate change studies. Instead of using a delta ensemble approach, the delta approach could also be applied to single model, but the projection estimates would therefore only rely on ones assumption that the single model employed was the ideal choice. In climate science there are tradeoffs between model complexity and expediency.

It should be noted that many high impact atmospheric events tend to occur on much smaller spatial and temporal scales than are covered by GCMs (e.g. lightning, freezing rain, ice storms, tornadoes). Two main strategies have been developed to help address this, the use of regional climate models (RCM's) [1] and statistical downscaling studies. Both strategies were used in Phase 2 for several of the more localized and shorter duration climate elements analyzed. For one set of climate hazards (e.g extreme temperatures), the technique of employing a climate analogue was also used to validate the "delta-method" for determining these climate hazard probabilities.

Regional Climate Models

Another approach for obtaining specific climate projection information is to run a very high resolution model once over the area of interest (so called 'dynamical downscaling'). In the simplest of terms one can either have 'many model runs at a coarse resolution' or 'few model runs at high resolution'. These high resolution models are called 'Regional Climate Models' (RCMs). There are RCMs available, but this data can be difficult to obtain and they still require a coarser resolution CMIP5 or earlier model to act as a precursor. Over North America, the North American Regional Climate Change Assessment Program (NARCCAP) has assembled less than a dozen RCMs for various time periods (http://www.narccap.ucar.edu/). As these models have a high temporal and spatial resolution (i.e. hours and tens of kilometers), there are fewer RCMs available than the CMIP5 Global Climate Model collection. In addition there are far fewer model runs from which to obtain an average climate change value. For this study, the decision was to use many coarser models from which to obtain the climate change signal rather than fewer higher resolution models. However, some of the probability results for one set of climate hazards in Phase 2 (extreme temperatures) were generated using the CANRCM4 model, and a discussion of associated uncertainties can be found under the specific descriptions for those climate hazards found below.

Statistical Downscaling

Statistical downscaling studies attempt to solve the spatial challenges by developing statistical links between GCM scale climate conditions and localized, short duration events (e.g. freezing rain/ice accretion and wind gusts). Historical, point location climate data is compared with conditions on the scale of GCM grids. Statistical links, so called "transfer functions", are then developed based on these relationships. After GCM projections are developed for a given future period, these transfer functions are then used to "downscale" GCM projection back down to local scales. Although much less computationally intensive than RCMs, individual statistical downscaling studies still require significant expertise and time for proper execution.

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[1] These are sometimes referred to as "dynamical downscaling" methods, to provide an analogous term to alternative "statistical downscaling" methods.

The main drawback of this technique is that climate projections can then only be obtained from specific observation station locations which have sufficiently long data records. This method calibrates historical climate observed at an observation station (for example Toronto Pearson Airport), with historical model data at a coarse scale (called 'predictors'), to obtain a statistical relationship. For example, perhaps the daily temperature observed is related to the modeled upper atmosphere wind direction. If one provides the future upper atmosphere wind direction from a climate change model, it could then be used as one of the variables to predict the future temperature. The difficulty with this process even with pre-constructed software is that spurious associations based on pure statistics and not climatology can be applied which would produce unrealistic future conditions. Certainly some expertise in the statistical software is required. Additionally, this method requires specially formatted input statistical climate model data which is only available for a few models – and for few model runs and RCPs. This procedure would have to be repeated for all station locations for which there was long term reliable station observation data to produce estimates of climate change for only those specific locations.

An IPCC document entitled "Guidelines for Use of Climate Scenarios Developed from Statistical Downscaling Methods" (Wilby et al, 2004) further discusses these procedures.

Phase 2 made use of previously published statistical downscaling studies to support future climate change projections (Cheng, Li and Auld 2011, Cheng 2014).

Climate Analogues

In the case of extreme temperatures (i.e. average temperature over 30 and 35 C, extreme over 40C) climate change projections were also compared to a "climate analogue." Climate analogues refer to locations in other geographical areas which possess historical climates which resemble in many respects the future climate of the study area. The future temperature regime for the 2050's for the City of Toronto is very similar to the current and historical climate of northern Kentucky. While not an exact comparison – there are significant differences in regional geographical characteristics, for example – rough, "order of magnitude" comparisons can be made to help further determine if climate change projections are in fact realistic and represent potentially "real" climates.

B.4 Determining the Probability of Occurrence of Specific Climate Hazards

Based on the general methodology presented above, the probability of individual climate hazards were determined. The following sections describe in detail how they were estimated.

Extreme Temperatures

Temperatures and temperatures related indices are the most basic and reliable of climate elements, and therefore associated trends and projected changes to temperatures have the greatest confidence. Thresholds are based on previous consultation work from Phase I, IEEE standards for switching and transformer equipment, with some additional consideration from impact studies found in the literature - for example, see (McEvoy, Ahmed et Mullett 2012). The lowest thresholds generally address load forecasting and related factors, while higher temperatures begin to consider direct impacts to equipment.

Historical values were assessed using observations for Pearson Airport for the 1981-2010 normals period. Climate projections were then developed using the AR5 ensemble and RCP 8.5 emissions scenario. For temperature related thresholds which require information of *daily* temperature information, such as heat waves, 40°C maximum daily temperature, or the 35°C average daily threshold, required special treatment and were developed using projections from the CanRCM4 regional climate model (RCM), again using the RCP 8.5 scenario. The "Delta method" was then used to apply the modeled changes in frequency of those days applied to historical averages. It should also be noted that the range indicated for the 40°C threshold is the result of applying two methods, RCM and GCM based estimates, since RCMs are again potentially prone to overestimates due to numerical instability[2], while the GCM method may under-estimate the frequency of extremes due to averaging from large spatial scales. These results were further checked against climate analogues in northern Kentucky, again to serve as a consistency check against model projections to determine if these projected increases were realistic.

Extreme Daily Averaged and Maximum Temperatures

Manufacturers of electrical distribution equipment specify both maximum *one day average* and *peak ambient* temperatures for the operation of transformers and other components. With global warming, it is unsurprising that all thresholds show an increase in event frequency. High temperatures which already occur several times per year increase further in frequency, and a few extreme temperatures which are currently less than annual occurrences (e.g. daily average temperature of 30°C) are projected to become annual events.

The most striking results were noted with some of the highest temperature thresholds. For example, days with peak temperatures of 40°C or greater are extremely rare, with only one incident on record for Toronto's Downtown station[3], and *no* events reported at Pearson Airport during its entire period of record. However, indications are that these extreme heat days may become an annual or near-annual occurrence by the 2050's. Similarly, days with 24 hour *average* temperatures of 30°C or higher are also extremely rare but may become, on average, annual occurrences. However, as with the historical behaviour of lower threshold values, there will likely be some years with several days over the "new" threshold, while other years will have none.

Multi-Day Heat Events and "Warm" Nights

Other measures of extreme heat have been proposed as having a potential impact on electrical infrastructure.

While heat waves, defined as three or more days with maximum temperatures above 30°C, are currently slightly less than annual events, these are expected to increase in frequency to just over 1 per year, on average, into the 2030's and 2050's. The length of a given heat wave may also increase into the future. Regional climate model results suggest that for the 2030's, an average of approximately four (4) consecutive days over 30°C will occur every year, and by the 2050's the estimate is as high as *six* (6) consecutive days over 30°C per year.

So-called "warm nights" have also been implicated in excessive stress on electrical infrastructure (McEvoy, Ahmed et Mullett 2012) through increases in nighttime electrical customer use (i.e. need for continuous use of air conditioning systems), combined with an inability for equipment to sufficiently cool under warm nighttime ambient temperatures. These have increased substantially in recent years, with average of greater than one event per year in the most recent 15 year period of record at Pearson Airport. This includes a record of five (5) warm nights in 2005, as well as the warmest overnight temperature ever recorded in 2006 at 26.3°C. However, while the literature has indicated that the latter element may be important for combined impacts and stress to the electrical system, most workshop participants were indeed quite skeptical that warm nights were an important measure for electrical system impacts, indicating they considered extreme *daytime* temperatures and electrical use as the dominant cause for impacts to distribution systems, rather than warm nights.

[2] Estimated increases in frequency from CanRCM4 were indeed so striking that they were checked against GCM based estimates for consistency. However, even when considering spatial and temporal averaging which will occur with the larger grid spacing and time steps inherent in GCMs, the ensemble still indicated significant increases in extreme heat days well beyond anything within historical experience.

[3] Three (3) consecutive days in July 1936 showed maximum temperatures reaching 40.6°C.

Spatial Geographical Variability

Mapping of extreme temperature days (**Appendix C**) indicate important temperature differences across the city, with temperature differences of 3-5 degrees between the shores of Lake Ontario and northern portions of the city. This is a direct result of the presence of Lake Ontario and its lake breeze, with cooler air from the lake keeping the shoreline and nearby areas cooler than parts of the city further north.

Extreme Short Duration Rainfall

The July 8, 2013 flash flood event in the GTA provided an example of the vulnerability of underground infrastructure to atmospheric events. While this particular case impacted Hydro One infrastructure, it is indicative of possible impacts to similar infrastructure owned and operated by Toronto Hydro. It was also an example of the importance and potential impacts generated by the loss of 3rd party infrastructure on which Toronto Hydro relies, emphasizing the interconnectedness of the electrical grid.

The threshold of "100 mm + antecedent" is based on rainfall accumulations estimated near the failure sites from the July 8th, 2013 event as well as other cases **(see Appendix C)**, although workshop participants felt this threshold might indeed be as low as 60 mm of rainfall. This threshold is in specific reference to high-intensity, localized rainfall events, characteristic of severe thunderstorms during the warm season. These generally last only a few hours in total, with the majority of that rain (over 50%) falling within a 1 hour time period. However, in every case, there was also antecedent rainfall in the preceding week which likely contributed to the overland flooding.

While these events are very difficult to predict even in short term forecasts, historical analyses on global precipitation extremes indicate that, in general, they will increase in intensity with climate change. However, the magnitude of this change, particularly for specific geographical regions, is not well understood (Kunkel, et al. 2013). Extreme, localized rainfall events represent an event type which cannot be modeled directly by GCM or even RCM output, and unfortunately no statistical downscaling studies for extreme thunderstorm rainfall exists for the GTA or nearby regions. However, global trends of historical increases in extreme rainfall are so significant that the climate team chose to increase annual probability score by one to account for this clear increase in thunderstorm extreme rainfall risk

Ice Storms and Freezing Rain Ice Accretions

Damage thresholds were also based on previous forensic work on freezing rain impacts, most notably Klaassen et al. (2003), as well as design requirements in codes and standards (CSA 2010a). These include thresholds for tree damage (15 mm) and for minimum CSA design (25 mm totals ≈ 0.5 inch radial). Freezing rain events represent an example of meteorologically complex events which require special treatment, and hence future projections presented here are based on tailored statistically downscaled results from published studies. Customized data specifically developed for Pearson International Airport were provided courtesy of C. Cheng (2011), using the same methodology employed in Cheng et al. (2011, 2014). Downscaled projections are expressed in *duration* rather than *accumulation amounts* due to the nature of the analysis methods used for downscaling. Climate projections of the parent large scale weather patterns (so-called "synoptic map typing") are based on the patterns and conditions which produce ice storms. For the downscaling work, these weather patterns were linked to the *duration* of freezing precipitation and not *amounts*, since total precipitation accumulation can vary significantly depending on available moisture. The duration threshold is also quite low (6 hours+) due to sample size, since storms of this magnitude or greater are infrequent.

However, these projections can be applied to other measures of ice storm severity given the following considerations:

1. Storms producing amounts on the order of 15 and 25 mm are of part of this "6 hour+" population, and we can therefore use results for the 6 hour+ storms as guidance for what will happen with 15 and 25 mm events; and,

2. Cheng et al. (2011, 2014) consistently showed greater increases in frequency for higher thresholds, hence storms with higher thresholds are expected to increase in frequency as much as or more than storms at lower thresholds;

Hence, changes in 6 hour+ event frequency are expressed as particular values, whereas the greater accumulation events are expressed as "greater than" some value.

Regional Differences in Severity

The severity of freezing rain events, specifically in terms of total ice accretion, tend to be lower for areas closest to Lake Ontario. In contrast to the summer, the lake acts to keep temperatures warmer during the early winter, an effect that appears to have been a factor during the December 2013 ice storm (see **Appendix C**). However, there are also indications from the forensic analyses that older portions of the city, particularly areas with a combination of significant, mature tree canopy cover and older overhead electrical distribution equipment, may be more sensitive to ice storms and are therefore more susceptible to smaller ice accretions.

It is very difficult to determine the return period or annual frequency of the extreme cases, since no events producing greater than 40 mm of total ice accretion have been reported in the GTA. The CSA standard for transmission line design (CSA 2010b) contains return period estimates for radial ice accretion for various locations[4]. Depending ones location within the City of Toronto, estimates for 30 mm ice accretion event (roughly 60 mm of total ice) indicate anywhere from a 1-in-150 to a 1-in-500 year return period event, termed "high" and "low" risk values, respectively, in table 3-2 in the main report. When increases in frequency of large ice storms is taken into account, these produce 35 year study period/"lifecycle" probability estimates of ~25% and ~8%, respectively[5]. However, these values are based on estimated return periods for extremely rare events, and the period of record on which they are based is far shorter than the return periods assigned to these ice accretion values.

Complexity of Freezing Rain Accretion versus Impacts

A myriad of measurements are given for freezing rain ice accretion due its complexity. Accumulations from airports, for example, represent *total* freezing rain amounts and not the thickness of accretions on overhead lines and structures, and hence certain freezing rain amounts can result in very different levels of ice accretion on infrastructure depending on numerous other factors (e.g. time, wind speeds, ambient temperatures). We also note that a significant majority of damage from the December 2013 ice storm was due to tree contacts at accretion thresholds lower than design requirements **(Appendix C)**, hence the inclusion of the 15 mm threshold.

High Winds

High winds can be produced by a variety of storm types and vary greatly in scale, intensity and duration. Design wind speeds found in codes and standards are based on large scale (synoptic) storms, while cases of extreme localized damage tend to occur with thunderstorm winds, including microbursts and tornadoes. This complexity introduces significant challenges when attempting to determine wind speed return periods for engineering design using historical data (Lombardo, Main et Simiu 2009), let alone the challenge of understanding how these might change under future climate conditions. Much like ice storms, wind gusts tend to also be affected by highly localized meteorological and geographical factors, and so meaningful projections cannot be directly extracted from GCMs or even RCMs.

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[4] The values provided in the CSA standard (CSA 2010b) are themselves based on the Chaîné ice accretion model. These were felt to be accurate enough to provide estimates of extreme ice storms in the GTA for this study.
[5] Based on climate design table, highest risk locations are Etobicoke and North York, with the lowest risk is in Scarborough (CSA 2010a), the former not surprisingly representing areas which are slightly further away from the lake.

The 70 and 90 km/h thresholds are based on practitioner consultation from Phase I as well as forensic analyses conducted for Phase II (**Appendix C**). The highest threshold, 120 km/h, is based on IEEE design standards for switch gear and transformers, as well as other impact thresholds work, for example the EF-scale and McDonald and Mehta (2006). Climate change projections for the 70 and 90 km/h thresholds were obtained from statistically downscaled results in the published literature (Cheng, Li et Li, et al. 2012, Cheng 2014) using statistical downscaling methods similar to those used for freezing rain, while projections for 120 km/h threshold were not available.

The statistically downscaled results indicate increases for both thresholds analyzed here. Cheng et al. (2012, 2014) also indicated that increases in frequency of wind gusts were consistently greater as thresholds also increased (e.g. 80 km/h gusts increased more than 70 km/h gusts), but did not conduct analyses for thresholds greater than the 90 km/h due to small sample size.

Tornadoes

Tornadoes are small scale, isolated events, and hence the only available historical data are records of observations of their occurrence and/or resulting damage. Probability scores for EF1 and EF2 tornadoes were calculated based on historical records of occurrence within the City of Toronto from the most recently available 70 years of observational data. Historical data prior to this was deemed too unreliable to contribute to statistics in a meaningful fashion. This inconsistency also renders historical trend detection nearly impossible[6]. Their localized and complex nature also prevents the development of meaningful climate projections through any of the methods described here, including GCM or RCM output as well as statistical downscaling.

As with extreme temperatures, lightning and ice accretion, the northern portions of the city such as the North York and Rexdale (northern Etobicoke) areas exhibit a higher risk of tornadoes historically, again mainly due to the effects of the Lake Ontario lake breeze, but this does not exclude the occurrence of tornadoes in and around the downtown core.

Two different intensity levels were chosen due to important differences in their impacts. Research on historical events indicated that concrete utility poles and other more resilient infrastructure only fail in EF2 or stronger tornadoes, and hence these were investigated separately to determine relative risk.

High Impact/Low Probability Events: Probability Estimates and Their Interpretation

Tornado probabilities were subject to further analyses beyond those used for most other climate elements. Probability scores in Table 3-2 of the main report reflect the probability of occurrence for a *single point*; however, since these values are extremely small, a different statistical perspective was needed to better represent the type of risk posed by tornadoes. The City of Toronto has recorded five (5) F-2[7] tornadoes on two separate days since 1900, with a possible sixth case in 1976 in North York. Hence, over the 35 year life cycle study period, there is a 46% to 61% chance that a weather event producing one or more EF-2 tornadoes will strike somewhere within the City of Toronto. While the probability of a direct impact to a specific point or location is extremely small, the likelihood of a significant event *somewhere* in the city between 2015 and 2050 is in fact considerable, and could entail catastrophic impacts to a portion of the city's infrastructure.

Lightning

As with all other climate elements, lightning can vary significantly in intensity, with the same storm producing different lightning strikes with amperage values varying by several orders of magnitude. Even

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[6] However, some very recent work in the United States may finally be revealing changes in tornado climatology potentially associated with climate change in the form of increased *variability* in occurrence[6] (Brooks, Carbin et Marsh 2014).

[7] The so-called "Enhanced" Fujita, or EF-Scale, has only been used in Canada as the official replacement to the F-scale since 2013; however, the EF-scale is intended to be compatible with F-scale ratings in the historical record, and so references to tornadoes using the F-scale can, for the purposes of this report, simply be considered as storms of equivalent intensity.

for a single thunderstorm event, there now exists a great deal of data currently available for use in analyses and even forecasting of lightning occurrence, particularly following the establishment of the North American lightning detection network in the late 1990's, and more recent "total lightning" detection networks being installed in the GTA for meteorological monitoring for the upcoming 2015 PanAm games. It is suggested that Toronto Hydro investigate this data to better understand how lightning interacts with the electrical distribution system, such as investigation of significant lightning events (e.g. July 21 & 22, 2002) to determine why and how they generated so many impacts.

Investigation of New Probability Scoring Methodology

Lightning probability scores differ from Phase I due the changes in the method used to calculate probability values. The annual average frequency of cloud-to-ground lightning strikes varies across the city from under 1.12 to over 2.24 lightning strikes per square kilometer. The highest frequencies are seen in the northwest portions of the city, while the lowest are seen in southern Etobicoke (see Figure B-7). However, each individual strike will only affect a very small area. Hence, the probability of impact was estimated using representative "target sizes" (i.e. areas which represent the usual footprint of a given piece of infrastructure). A further assumption was tested assuming that lightning strikes would need to be within 25 meters of a piece of overhead infrastructure to produce negative impacts. The resulting probability scores were felt to be more representative of field conditions, particularly when considering the frequency of lightning impacts reported by Toronto Hydro (**see Appendix C**). These were also weighed against mounting evidence that lightning occurrence will increase in frequency with climate change, for example (Romps, et al. 2014), but by an uncertain amount[8].

Using two different "target" sizes provided by AECOM representing large (0.015 km^2) and small municipal (0.0001 km^2) transformer stations, probability of impact were calculated and compared, with and without the assumption of a 25 meter radius of impact. The results are provided in Table B-2 below.

Figure B-7 Lighting Distribution in Greater Toronto Area for 1999 – 2008 period, Lightning Strikes / /km^2•yr)

[8] Romps et al. (2014) indicated a potential increase of ~50% in total lightning strikes in the continental United States by the end of the century. However, while their methodology proved to be quite robust when compared to observational data, there was no assessment of GCM error in recreating the indices which drove this increase. Their index and model also appear to have difficulty with lake breeze related convection, which is of great importance for Toronto's lightning climatology. Hence, the RSI climate team chose to not apply these percentages as there remains too much uncertainty in how global climate change will impact lightning frequency in the Toronto area specifically.

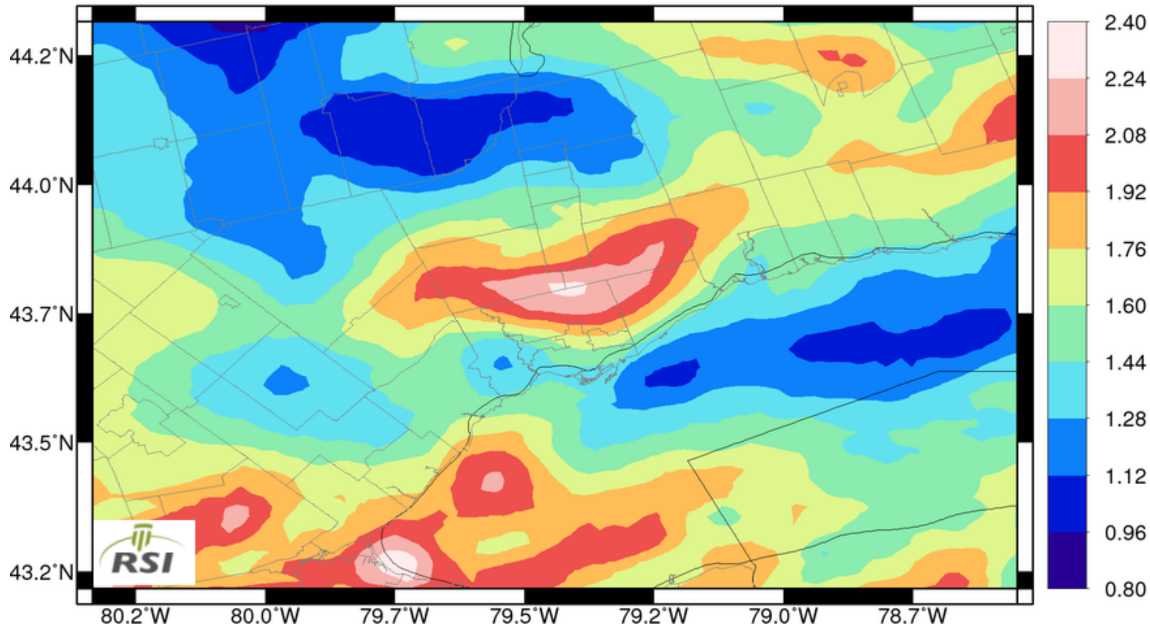
44.2°N
44.0°N
43.7°N
43.5°N
43.2°N
80.2°W
80.0°W
79.7°W
79.5°W
79.2°W
79.0°W
78.7°W
2.40
2.24
2.08
1.92
1.76
1.60
1.44
1.28
1.12
0.96
0.80
RSI

Table B.2 Lightning Strike Probabilities Transformer Stations

Target Type	Annual Lightning Frequency (km^{-2})	Annual Probability Score (2050's)	Study/"Lifecycle" Period Probability Score (2015-2050)
Large Transformer Station	1.12	1	5
Large Transformer Station	2.24	2	6
Municipal Transformer Station	1.12	0	2
Municipal Transformer Station	2.24	0	3

Snow

Snowfall thresholds were chosen following the second workshop and are intended to address "nuisance" events, such as those which require the application of deicing agents (5 cm+) and those leading to restricted to site access (10 cm+). The group chose to focus upon nuisance events at the "lower end" of the snowfall accumulation spectrum, rather than extreme snowfall events, since overhead systems were not considered by workshop participants as being sensitive to direct snow loading. Historical data indicate that the total number of days exceeding these thresholds are decreasing, as expected with global warming, but not at all rapidly enough to consider snow a "disappearing" hazard. In addition to this, and in contrast to days with small snowfall totals, days with extreme snowfall will continue to occur well into the future, and may in fact *increase* in intensity with further warming (Kunkel, et al. 2013). Hence, days in which snow will pose a hazard to infrastructure will continue well into the coming decades, even with continued warming.

Frost

Participants at the second workshop also indicated frost depth as being a concern for civil infrastructure, particularly following the extreme cold experienced during the 2013-14 winter season. As with other cool season hazards, the frost free period is expected to increase in length, which will result in less frost penetration on average, although occasional extremely cold winters will continue to occur well into the future. Frost depth calculations were not conducted for this project due to time and resource constraints, as well as significant variability associated with frost depth under the same atmospheric conditions. The latter is impacted by soil moisture, thermal conductivity, snow cover, and several other factors which vary greatly across the city. However, if frost heave is considered an important risk, further study could be conducted, using the 2013-2014 winter season as an example case study.

Complex Interactions

Complex interactions are generally defined as interactions which generate negative or unwanted impacts to infrastructure but which are the result of a *sequence* of events involving both climate and human factors. For the sake of simplicity, we have considered most climate elements in isolation. As the forensic analyses indicate, however, most real-world climate impacts are often attributed to one dominant element but with additional impacts from other simultaneously occurring hazards.

High Humidity Near-Zero Winter Environments

This complex interaction type was identified through both workshops and forensics work, and their occurrence appears to result from a *sequence* of events involving a combination of minor ice accretions followed by the application of de-icing agents. These are characterized by multi-day periods in which temperatures are near zero degrees, often "crossing" the zero degree line multiple times, and include multiple periods of freezing or frozen precipitation. Ice accretion may be from a combination of freezing rain, wet snow or rain-on-snow “re-freezing”, with possible *additional* accretion from fog which is often present between periods of precipitation. These very moist conditions are then coupled with de-icing agents to cause short circuits, resulting in pole top fires and other incidents associated with short circuiting of insulators and switch gear.

Such a complex events entail the sequential occurrence of several meteorological factors coupled with human factors and are therefore impossible to project using the current set of climate change projection techniques. However, having identified these conditions, their occurrence could be monitored and even anticipated several days in advance using a combination of current conditions and short term weather forecasts, allowing for the mobilization of operational resources. The January 31st to February 3rd, 2003 event described in **Appendix C**, and a similar event which was identified for the transmission sector “sister” PIEVC study (January 2000) can be used to form the basis of pattern recognition for future events of a similar nature.

Tree Growth, Disease and Pests: Implications for Overhead Infrastructure

The second important complex interaction identified by our analysis entails the impacts of environmental changes affecting tree growth and health, affecting their resiliency to climatic loading. Higher average temperatures are expected to extend the growing season. This will likely result in faster tree growth and necessitate more spending on right-of-way maintenance, as well as possibly increasing tree vulnerability to wind and ice loading. The impacts of new and/or exacerbated disease and pest conditions can also increase tree vulnerability to damage, with the December 2013 ice storm and impacts on emerald ash borer infested trees being an example of this increased vulnerability. The complex interaction between accelerated growth rates, disease and pest regimes, and the resulting changes in vulnerability to adjacent infrastructure have only recently been identified and are not well understood, but should be subject to further study.

Appendix C
Forensic Analysis of Weather Related Power Outage Events

Brief Forensic Analyses of Weather Related Power Outage Events

C.1 Introduction

To better understand the nature and magnitude of climatic and meteorological events responsible for impacts to Toronto Hydro's electrical distribution system, as well as neighboring LDCs, RSI staff conducted forensic analyses of events generating significant impacts to the system. Information on the nature and extent of those impacts was compared to meteorological data to understand the nature and magnitude of atmospheric loads and conditions associated with these impacts. The analyses below consist of what can be termed either "single incident" or "cross-incident analyses," the former consisting of a "deep dive" into an individual events (listed in **Table C.1**), while the latter consists of the inter-comparison of numerous similar events to help determine commonalities.

In particular, events that were deemed meteorologically complex or multi-causal in nature, as well as meteorological events representing instances of impact thresholds, were selected for further assessment under "single incident" analysis to help refined our understanding of the thresholds at which impacts begin to occur, and what the causes and drivers of those impacts might be. Winter storms (including freezing rain events), summer thunderstorms, and a high heat case were evaluated for more detailed analyses. Other cases, such as fall season high winds, were evaluated under "cross-incident" analyses, for the purpose of evaluating and cross-checking thresholds determined from other sources (e.g. literature and practitioner interviews).

Several data sources were consulted for both meteorological and infrastructure impacts information. The former included data from Environment Canada's national climate data archive, Toronto Region Conservation Authority (2014) precipitation data, consultant reports (Cole Engineering 2013), as well as remote sensing data where appropriate. Impacts data were provided directly by Toronto Hydro, as well as outage incident press releases, newspaper accounts, and internal report (where available). Events which underwent detailed analyses are listed below in **Table C.1**.

C.1.1 Event Types and Relation to Impacts

Any number of climate and weather related events are capable of producing unwanted interactions with power distribution infrastructure. Direct impacts from severe winds, ice accretion, heavy/wet snow, extreme heat and lightning can directly overload support structures and conductors, as well as adjacent vegetation, which is also prone to failure, causing secondary impacts. Underground infrastructure is sensitive to flooding and longer term processes, such as enhanced corrosion through seepage and penetration of deicing agents. For each hazard, there are generally a small sub-set of mechanisms which can produce them. High winds during the warm season are associated with severe thunderstorms (including downbursts, microbursts and tornadoes), which tend to be intense but localized, whereas should season and winter severe winds are associated with large scale low pressure systems (so-called "synoptic lows"). Winds associated with these events are more widespread and can last for several hours to more than a day. Similarly, precipitation events are generally associated with thunderstorms during the warm season and low pressure systems in the cool season (snow storms, ice storms, etc.). It should become quickly apparent that several event types can occur simultaneously, resulting in multiple cause power outage events.

Identification of event type is critical in understanding what types of impacts to expect at different times of year, including duration of the event, potential challenges for response and maintenance, presence of simultaneously occurring hazards, and for some event types what antecedent conditions to monitor to help anticipate or forecast weather related impacts. During the late spring and summer, for example, a number of significant thunderstorm events tend to be proceeded by high temperature and humidity combinations which themselves may have generated impacts on the system. While individual events are indeed complex, infrastructure operators can begin to understand the antecedent conditions to help increase readiness for such events.

Event type identification is also critical to climatological analyses and the development of adaptation responses. More localized, short duration events present significant challenges for assessing future climate vulnerability and risk, but less complex climate elements, such as temperature, are far less difficult to analyze, and confidence in both the consistency of historical data as well as certainty in projected trends are much greater.

Adaptation responses, particularly those regarding maintenance and operations, must take into account the nature of the events generating impacts. How much lead time can one expect for storm warnings, if any? What hazards may be posed to repair crews, or restrict access to damage locations? For example, a number of recent press releases indicated that full repair efforts have been postponed based on the timing of high winds, with crews waiting for the “worst to pass” before executing major restoration efforts (see “Superstorm Sandy” analysis below). More sophisticated operations and management actions such as these are critical to optimizing response to severe weather events.

C.1.2 Brief Note on Impacts Data

Staff at Toronto Hydro kindly provided outage incident data for this analysis, which proved invaluable for determining the types and magnitude of events which were responsible for significant power outage events. However, this type of cross-disciplinary forensic analysis was not the original intent of the failure database, and as such there were a number of challenges which presented themselves when using the data.

Most notably, it became clear that data collection was inconsistent throughout the period of record. While the database contains events from the years 2000 to 2013 inclusive, earlier events have dozens of reports per date, while more recent major outage events do not. In 2013, the July 8th flood and December 21st-22nd ice storm, which Toronto Hydro staff indicated were among the worst in their history, have very few listings in the database. This is likely due to changes in reporting practices, which apparently began in 2007 judging from the frequency of weather events with 20+ reports each, but this requires confirmation Toronto Hydro staff.

This emphasizes the need for the standard forensic practice of consulting and comparing multiple sources of data. For example, impacts data can be used to indicate if event intensity, such as high winds, could have been significantly higher than meteorological measurements may indicate. Conversely, meteorological data can be used to either guide and/or refine the search for impacts data, or even correct coding or other errors in impacts data.

C.2 Toronto Hydro Outage Data

As indicated above, outage data from Toronto Hydro were interrogated to identify significant outage events which could be used for further study. Days with 20 or more reports were identified, and these were further refined by checking for potentially related reports on days before and after identified event dates. While it is fairly clear that data from 2007 to 2013 were collected under different reporting requirements, 2000-2006 appear to be consistent, and so data for this period will be evaluated here.

A total of 46 weather events were identified with this methodology. Just over half (54%) of these events occurred over fairly extended periods of 12 to 48 hours; this has implications for maintenance and repair response measures. For fall wind storms and winter precipitation events, this quite literally meant several consecutive hours of either high winds or precipitation generating impacts, while for summer events this likely represents two or more episodes of thunderstorm activity within a one to two day period.

C.2.1 "Worst" Years

In terms of the "worst" years, we have two measures; total number of events, total number of damage reports for these events, and number of damage reports per event. The years 2000 and 2005 are tied for the most events in a given year (9). In terms of total reports for all events combined, 2000 has the highest at 6—followed by 2003. In terms of average event severity, the total number of reports was divided by the number of events in a given year as a rough measure of "average" severity for a given year. The year 2003 had the highest average, with an average of just over 84 reports per event. Even though 2000 and 2005 contain single major events, their averages fall well below those seen in 2003, 69 and 56 reports per event respectively.

The year 2000 followed two main themes. A series of severe winter storms in February were responsible for multiple reports and were characterized by either freezing rain or heavy wet snow and rainfall combinations, both characteristic of "warm" winter storms producing heavy precipitation at temperatures near or at 0°C[1]. This was followed by late spring to summer severe thunderstorm events, including the May 12-13, 2000 event, as well as a thunderstorm event on July 14, 2000, which generated over 100 reports through mainly lightning related damage.

The year 2005 was characterized by high heat and humidity during the summer months, which either directly contributed to infrastructure underperformance as well as severe thunderstorm events, most

[1] At temperatures at or just below freezing, atmospheric water content is at its highest while still being able to support ice formation; hence temperatures near zero are associated with either freezing rain or high density, wet snow capable of physically coating and loading overhead lines and trees.

notably the August 19th, 2005 storm. This was followed in the fall by a series of wind storms which produced scattered outages throughout the GTA, which was among several areas across Ontario which were impacted by intense fall windstorms (e.g. over 100,000 Hydro One customers lost power during the November 6, 2005 synoptic storm; Hydro One 2005).

Finally, in 2003, Toronto Hydro was impacted by a similar combination of event types, with two winter storms in rapid succession in February, followed by severe thunderstorm activity during the late spring and summer, followed by large scale wind events from late September to mid-November.

All of the so-called "worst" years identified here have the following in common:

- Repeated events, often with only days between similar types of incidents
- Two or three "modes" of high impact weather events in the same year, specifically:
    - "warm" winter storms, meaning they were associated with temperatures at or just below 0°C with some combination of heavy snow, freezing rain or even rainfall mid-winter;
    - Severe thunderstorms and high heat and humidity during the summer;
    - Multiple fall season large scale (synoptic) wind storms;
- One major event which produced over 150 damage reports

These findings can help with better planning and anticipation of particularly high impact years. For example, periods of very high heat and humidity should be watched closely, as they are occasionally followed by severe thunderstorm events when the heat "breaks" with the passage of a cold front or other air mass change. Fall and spring large scale wind storms will occasionally occur in series, as occurred between September 29th and November 13th 2005[2], repeatedly impacting the same area. These findings appear to be consistent with recent experiences; in 2013, Toronto Hydro suffered two major weather related outage events, one in the summer from a severe thunderstorm event producing extreme rainfall, followed in the winter by a freezing rain event.

It may also be possible to anticipate a particularly severe damage year since the "major" events producing over 150 reports tend not to occur in isolation but usually occur in years with a number of less severe but still significant events, although the consistency of this pattern requires further research.

C.2.2 "Worst" Events for 2000 to 2006 Period

The two events with the greatest number of reports, May 12-13, 2000 and August 19, 2005, were both subject to detailed analyses. Another three events (Jan 31-February 4, 2003; July 14, 2000 and July 21-22, 2002) produced over 100 reports, with September 19, 2003 coming very close at 99 reports.

What is of particular interest is the number of severe thunderstorm related reports which were accompanied by mainly lightning related outages. Even for storms which included extreme rainfall and high winds related impacts, lightning appeared to be the dominant factor in producing outages. The July

[2] A fourth synoptic storm occurred on November 15 to 16, 2005 but did not cause significant impacts to Toronto Hydro's infrastructure, instead tracking to the north east and affecting Georgian Bay and the "Nickel Belt," causing over 50,000 Hydro One customers to lose power.

21-22, 2002 event is particularly noteworthy. Although we do not have detailed lightning information, such information is available from the national lightning detection network, and the frequency and amperage of lightning experienced during this thunderstorm series could be investigated to determine what made this particular lightning storm so damaging to the system in comparison to any number of other events. A summary of all events identified through this method is provided in **Table C.2**.

C.3 Fall and Winter Storms

C.3.1 December 20-22, 2013 Ice Storm

The December 2013 ice storm in south central Ontario has been deemed the worst ice storm in Toronto Hydro's history in terms of impacts to the city's distribution system. It is estimated that at the peak of event during the overnight hours between December 21st and 22nd, ~300,000 customers were without power. The most recent estimates of total damage incurred by Toronto Hydro's distribution system has been placed at nearly $15 million, specifically for restoration and repair (Toronto Star: March 31, 2014).

The storm also impacted several other adjacent LDC's, including:

- Enersource (Mississauga), 91,000 customers affected (Mississauga.ca 2014);
- Hydro One Brampton, 15,500 customers (Brampton Guardian, Dec 30, 2013);
- PowerStream (York Region[3]) 92,000 customers (Markham Economist and Sun, December 31, 2013);
- Veridian (Pickering/Ajax/Port Hope) 40,000 (Veridan Connections Press Release, Dec 22, 2013);
- Whitby 13,000 (Oshawa This Week, Dec 22, 2013)
- Oshawa Public Utilities Company ~30,000; and,
- Rural areas of Clarington (Hydro One) ~46,000 (Ajax News Adviser, Dec 23, 2013)

Meteorological data from both Environment Canada and Toronto Region Conservation Authority stations were analyzed to estimated ice accretion totals and rates in and around the GTA, which were then compared to impacts on electrical distribution infrastructure in the area.

C.3.1.1 Impacts and Meteorological Conditions: City of Toronto

Figure C.1 compares estimated ice accretion values at Pearson and Buttonville Airports with the total number of customers affected reported by Toronto Hydro. While ice accretion values were not directly reported by any of the stations evaluated, they can be estimated by combining hourly observations of precipitation type with daily rainfall totals. Freezing rainfall and drizzle totals were estimated by first determining the fraction of precipitation falling as freezing rain or drizzle (since liquid rainfall and snow were also reported on some days). Accretion rates were then weighted by precipitation type (1 for rain, 0.5 for moderate rain, and 0.1 for drizzle, based relative accretion rates from Klaassen et al. 2003), which were then further developed into estimated hourly average accretion rates. These were then summed for each day between December 20th and December 23rd for both Pearson Airport and

[3] PowerStream also suffered the complete outage of their website, which had not been designed to receive the traffic volumes which it encountered during the event (Markham Economist and Sun, December 31, 2013).

Buttonville Airports, the only locations near the City of Toronto for which hourly observations of precipitation type were available. Given that several locations experienced both above zero temperatures and liquid precipitation during the multi-day period under analysis, and that ice accretion on overhead structures, lines and trees is further affected by wire or branch diameter and surface characteristic, it is likely that estimated multi-day ice accretion estimates are *over*-estimates of true accretion values. This will be taken into account during the discussion of impacts.

Ice accretion totals for the 3 day period are over 30 mm for Pearson Airport and nearly 35 mm at Buttonville. A review of hourly temperatures at both airport for the same time period (not shown) also indicate that Pearson Airport was above zero for several hours longer than Buttonville, implying that less freezing precipitation accretions may have been retained there than at Buttonville. A comparison of photographs taken following the storm, both of ice accretions on different objects, as well as the apparent severity of tree damage to areas near the two airports provide evidence that ice accretions immediately north of the City of Toronto incurred ice accretion amounts several millimeters greater than those experiences in northern portions of the city (**Figure C.2**).

The relative impacts of temperature regimes become readily apparent, however, when ice accretion estimates are isolated to include only freezing rain totals beginning late morning on December 21st, excluding accretion contributions from the December 20th to 21st overnight precipitation episode. Ice accretion values become only 13 mm for Buttonville and *25* mm for Pearson. This implies to important elements for understanding how ice accretion values evolved in different portions of the GTA, particularly:

- Higher than 13mm ice accretion values for municipalities north of Toronto cannot be explained without including precipitation amounts from the earlier December 20th-21st episode;
- Lower than 25 mm ice accretion values near Pearson Airport likely cannot be explained without considering periods of >0°C temperatures, combined with the effects of liquid (non-freezing) rain and drizzle

Estimate ice accretion values on the order of ~20 mm were present when outages began, with amounts of 18 and 23 mm at Pearson and Buttonville respectively just prior to first report of 8,500 outages. Press releases indicate that this initial damage was indeed focused in northern and northeastern portions of the city (Toronto Hydro Press Release; December 21, 11:58 PM); accretion values estimated from these airports are likely representative of those experienced in the first areas suffering from widespread power outages. Rounding down to allow for some ice accretion losses due previously discussed factors, a range of 15-20 mm are likely responsible.

To better understand conditions in and near the downtown core versus surrounding portions of the city, hourly temperatures at the Downtown meteorological station (located at the University of Toronto campus on Bloor Street) and Toronto Island's Billy Bishop airport, were compared to those at Pearson Airport (**Figure C.3**). Radar imagery (**Figure C.4**) indicates that precipitation elements were moving very rapidly (over 100 km/h) during the freezing rain event, hence hourly precipitation reports at Pearson Airport are likely representative of the occurrence or non-occurrence of precipitation conditions at stations located less than 20 km to the ESE, where manned observations of precipitation type are not available. Precipitation reports from Pearson Airport were therefore superimposed on temperature plots to indicate when precipitation was occurring, and more importantly to imply whether or not precipitation was falling as liquid rain or freezing rain for downtown locations for a given hour.

Figure C.4 shows hourly temperatures at the three Toronto locations, implying that the city's downtown core likely received much less freezing rain than surrounding areas (the so-called "horseshoe" of former suburbs), and that accretions from December 20th and most of December 21st would have been unable to remain on exposed surfaces. However, a period of particularly heavy precipitation overnight between December 21st and 22nd correspond with temperatures below freezing, with both downtown stations falling below 0°C between 10 and 11 PM on the night of the 21st.

Toronto Island Airport reported 17.7 mm on December 21st and 13.9 mm on December 22 and the Downtown station reported 17.0 mm and 14.3 mm, respectively. Assuming the majority of precipitation on December 22nd fell as freezing rain, with some additional contributions from precipitation late in the evening on December 21st, ice accretion values in the downtown core were likely on the order of ~15 mm, compared to estimated values in excess of 25-30 mm or more estimated for northern portions of the city and adjacent municipalities. The implication, however, is that severely impacted portions of the city of Toronto near the downtown core may have seen significantly smaller ice accretion values than other parts of the city but still suffered from multi-day power outages.

Estimates of ice accretion rates at Pearson and Buttonville airports, along with the severity of impacts in the downtown core, which likely only saw ~15 mm, suggest that the final hours of the freezing rain event produced much more rapid ice accretion rates than earlier phases. Between 11 PM December 21st (when downtown stations were below 0°C) and 9AM the following morning, only 7 hours of freezing rain was observed at Pearson Airport. Even with significant averaging inherent in ice accretion rate estimates calculated in **Figure C.1** for Pearson and Buttonville airports, freezing rain ice accretion rates peaked during the early morning hours of December 22nd, estimated at 2.13 mm/h at Pearson and 1.25 mm/h at Buttonville, compared to estimated hourly rates on preceding days (0.79 and 0.95 mm/h for Pearson; 0.92 and 1.19 mm/h for Buttonville). A review of radar imagery for that time period (**Figure C.3**) indicates that a particularly heavy area of precipitation, associated with a small scale meteorological feature, tracked over the GTA and surrounding areas in the early morning hours of December 22nd. This corresponded with the rapid increase and peak in reported outages, and was likely responsible for a large portion, if not the majority, of ice accretions experienced in and around the downtown core.

Immediately following the ice storm, one spokesperson for Toronto Hydro indicated the worst damage appeared to be following highway 401, but this was prior to knowing full extent of damage in Scarborough (Toronto Star; December 23, 2013). Outage maps of the city the following day showed a clear delineation of much less severe impacts south of Bloor Street versus areas north and east of the downtown core, however a lack of both detailed impacts data and/or meteorological observations, particularly for Scarborough and East York, complicate better diagnoses of the reasons for these differences. At these scales, there could be a complex interplay between local topography, infrastructure characteristics, tree canopy extent and/or health, as well as small scale meteorological elements (e.g. there may have been marked small scale differences in temperature gradients or locally enhanced precipitation). Without higher resolution data, all potential causes for these boundaries remain speculative.

C.3.1.2 Impacts and Atmospheric Conditions: Durham Region LDCs

Analyses of impacts to LDC's east of the city of Toronto are complicated by a lack of both detailed impacts information as well as aforementioned meteorological observation data. Only daily precipitation totals and hourly temperature data are available for Oshawa Airport, and only a small number of TRCA stations were available to provide temperature data for the Ajax and Pickering areas, but did feature high sampling rates (5 and 15 minute intervals). However, given the characteristics of damage reported by the press, it can be easily surmised that a significant amount of ice accretion occurred in the region.

A review of hourly temperature data for Oshawa Airport indicate that for the 72 hour period beginning at 4 PM on December 20th, there were only ~4 hours in which temperatures were at or just slightly above 0°C, specifically between 11 PM December 22nd and 2 AM December 23rd. This suggests that the majority of the precipitation on December 21st and 22nd, with daily totals of 17.6 mm and 10.3 mm, respectively, was likely freezing rain. Accretions could have also included some of the 8.1 mm reported on December 20th, where temperatures remained below 0°C after 4 PM. Similarly, temperature data from a TRCA weather station at Bayly and Church in Ajax (**Figure C.6**) indicate ~3.5 hours mid-day on December 21st, for which temperatures were above 0°C for the same time period, as do temperature data for the Brock West Landfill site, north of Pickering, for ~3.3 hours (TRCA 2014). The overnight temperature spike indicated at Oshawa Airport on December 21st and 22nd also shows up clearly for these two stations, but remains *below* freezing. Temperatures remained below 0.5°C for all three sites, even with sampling rates of 15 and 5 minutes for the two TRCA sites. Hence, when considering temperature conditions associated with the event, freezing rainfall totals in the ~25-35 mm range are likely for portions of southern Durham region.

Restoration times were checked in local newspapers and available press releases from LDCs (mainly Veridian) to ascertain how quickly Durham region LDCs recovered from the event when compared to Toronto Hydro. A rough benchmark of 90% restoration was used to compare the LDCs and using the morning of December 22nd as a start time for full restoration efforts:

- Veridian (Ajax, Bowmanville, Newcastle, Port Hope), restored by 8 PM December 24th, 2.5 days;
- Oshawa PUC, restored mid-day December 23rd, ~1 day;
- Whitby Hydro, fully restored by December 24th, 1-2 days;

These are compared to Toronto Hydro, which required more than **5** days to restore power to 90% of customers affected by the event. The effects of scale on Toronto Hydro's distribution system, as well as increased vulnerability from aged infrastructure, aged trees adjacent to overhead lines, and difficulty servicing and accessing equipment cannot be underestimated. There are also likely differences in the ratio of response capacity (e.g. number of personnel versus number of customers) as well as shear geographical area to be covered. Significant differences in recovery time appear to be an excellent example of how logistical challenges for larger metropolitan LDCs can result in marked difference in vulnerability when compared to much smaller LDCs servicing small cities and rural areas, in spite of the fact that Durham Region appears to have, on average, been impacted by similar to possibly higher ice accretions than large portions of the City of Toronto. Overall, at least in the case of the December 2013 ice storm, larger LDCs appear to be more susceptible to ice storms than smaller ones, likely due to a combination of factors.

Veridian indicated that by noon on December 26th, only ~1,700 of the original 40,000 customers who had lost power remained without service (DurhamRegion.com, Dec 27, 2013), and that these mainly consisted of particularly difficult to repair elements, such as backyard supply lines. Similar comments were made by Toronto Hydro staff regarding back-lots which needed to be serviced and which were quite common in some parts of the city, although indications are that these will be eventually phased out.

Tree impacts were again named explicitly as the cause of much of the damage in Durham Region (Ajax News Adviser; December 23, 2013). On December 26th, Oshawa PUC continued to report problems with tree branches falling on lines generating new damage, and on the same day a statement by utilities officials in Whitby indicated that recent snowfalls had added more weight to ice covered tree limbs, and warned of an increasing the risk of breakage and the potential for new damage (Durham Region.com, December 26, 2013). These concerns are again similar to those expressed by Toronto Hydro and indicate an aspect of ice storm damage which should be considered in response and recovery methods.

C.3.1.3 Case Specific Findings December '13 Ice Storm:

While ice accretion values likely approached or even slightly exceeded minimum CSA design requirements (CSA 2010) for overhead systems for small portions of the city of Toronto, Durham Region, and other areas, it appears that the vast majority of damage inflicted on overhead distribution lines during the ice storm was due to the impacts from falling tree limbs. Immediately following the ice storm, tree damage was indicated as "worse than originally anticipated" (TH Press Release, Dec 23, 2014, 3 PM) in spite of what has since been termed aggressive tree trimming programs in place prior to this event. At least two municipalities, Brampton and Whitby, also indicated concerns that emerald ash borer (EAB) affected trees posed particular risks due to their weakened state. Tree impact damage continued for several hours to several days after significant ice accretion ceased. One line worker described how falling tree limbs continued to damage lines even during maintenance, and that repairs had to be redone at some locations (Toronto Star: December 23, 2013). This is also consistent with continued tree fall observed by one of the authors (S. Eng) during the mid and late-afternoon of December 22nd in central Etobicoke area, again several hours after significant ice accretions had ceased.

It is hypothesized that continued damage may have been due to both continued light freezing and frozen precipitation which continued periodically at various locations through December 22nd and 23rd, and gradual loss of fiber strength from prolonged loading.

During the recovery effort, there were notable. increases in estimated restoration times as efforts progressed. Estimates in earlier press releases indicated restoration times of 12-16 hours were expected, while *eventual* restoration times, particularly for the remaining 10% of customers to be restored, were in excess of 5 days.

Total ice accretion amounts for areas surrounding the City of Toronto were likely much higher than those experienced in the downtown core and surrounding areas. In areas within Durham and York Regions, temperatures generally remained cold enough to maintain freezing rain ice accretions which began as early as the afternoon of December 20th. As one approached the downtown core of the City of Toronto, the event transitioned to one better characterized as a relatively short duration but fairly intense period of freezing rain, the majority of ice accretions and impacts occurring during the overnight and early morning hours between December 21st and 22nd, rather than multi-day ice accretions apparent in areas surrounding the city. These characteristics of the freezing rain event need to be understood when considering differences in both impacts and vulnerability of Toronto Hydro's distribution network when compared to LDCs in adjacent municipalities.

Press releases in the days following the event placed a clear emphasis on electrical stand pipe damage to individual homes in Toronto Hydro press releases. It is hypothesized that, as ice accretion amounts increase, more and more elements of the electrical system are damaged, hence repairs become exponentially more difficult to execute, as impacts progress from isolated large branches on lines to entire trees, and as a higher percentage of individual residences suffer damage, as indicated by the widespread damage to individual residential standpipes suffered in the Toronto Area. Similar impacts were noted during the January 1998 ice storm in Quebec, where all not only transmission corridors were severely damaged, but also individual residential lines, making recovery especially challenging due to numerous repairs on the individual customer level.

A lack of manned observations of precipitation type south and east of Pearson Airport was found to be frustrating to the investigation, particularly for **Toronto City Center** and **Island Airport** stations as well as **Oshawa Airport**. While useful findings were developed based on precipitation estimates and proxy analyses (e.g. use of temperatures to imply precipitation type), manned observations confirming precipitation type and accumulation rates would greatly assist with diagnoses of conditions in downtown Toronto as well as for Durham Region LDCs. Impacts data in the form of outage timelines and descriptions of damage could then be combined with more representative meteorological data to compare relative sensitivities of adjacent LDCs to ice storm conditions. A lack of any meteorological observations for East York and Scarborough were particularly frustrating, given apparent (and as of yet unexplained) boundaries in impact severity for these portions of the city.

Similar problems were encountered with TRCA data. While some locations provide precipitation data during the winter, all were well north and west of both Toronto's downtown core, as well as populations centers in Durham Region impacted by the storm. This indicates the need for improved monitoring of winter precipitation in populated areas of the GTA, since differences in impact severity between different municipalities is difficult without detailed observational data on precipitation characteristics.

A significant meteorological component of the event, especially for areas in and around Toronto's downtown core, appears to have been a particularly heavy episode of precipitation during the early morning hours of December 22nd associated with a small scale meteorological feature. This implies that for high impact winter events, even those associated with large scale processes, difficult to forecast smaller scale[4] meteorological phenomenon, perhaps only a few dozen kilometers in physical extent and affecting a given location for only a few hours, may still play an important role in generating impacts. This emphasizes the need for continued monitoring of weather forecasts and meteorological remote sensing data such as radar, since the onset of impacts from these types of phenomenon can be quite rapid and are akin to severe thunderstorm events during the warm season.

In addition to Toronto Hydro, several other LDCs also indicated marked differences in the severity and extent of impacts within individual municipalities. Enersource outage maps, for example, showed particularly severe impacts in the northwestern portion of Mississauga. Veridian indicated that southeastern portions of Ajax suffered more damage and were more difficult to restore, mainly due to aged trees characteristic of the area (Ajax News Adviser; Dec 23, 2013), and similar reports of particularly heavily affected areas were also noted for Pickering (DurhamRegion.com; Dec 24, 2014), although a specific cause for these difficulties was not given. More detailed studies of these localized disparities in impacts would be extremely informative. These would likely consist of surveys and could include a review of individual incident reports and the collection of visual materials, as well as an assessment of contributing factors such as tree species and canopy cover maps, infrastructure age and characteristics, and so on.

C.3.2 Other Winter Storms

For comparison to the December 2013 event, other ice storms were reviewed to determine if thresholds from previous research (Klaassen et al. 2003) were directly applicable to the City of Toronto and to also determine the severity of impacts from less severe and widespread storms. Klaassen et al. (2003) indicated that ice storms with as little as 15 mm of total ice accumulation have resulted in widespread power outages, mainly due to tree limb impacts, and while this agrees well with analyses from the December 2013 storm, other events should also be interrogated.

C.3.2.1 January 31st to February 4th, 2003: Complex Winter Event

The period between January 31st and February 4th, 2003 saw multiple types of precipitation and a variety of conditions impacting the Toronto Hydro distribution system, and resulted in over 50,000 customers being affected at various time by power outages (ITIS data). Some 160 incidents were reported in the ITIS database beginning on the evening of January 31st through to February 4th, including blown transformers and current limiting fuses, tracking problems, and some instances of galloping and tree contacts. On the night of February 3, 2003, “hundreds” of car accidents and numerous power outages were blamed on a combination of freezing rain and high winds, mainly across Scarborough and North York (Toronto Star, February 4, 2003). These impacts were the result of a complex weather event which involved two large scale low-pressure systems, several different types of precipitation, and significant associated temperature variations over the course of 5 days.

[4] In meteorology, these are termed “meso-scale” weather phenomenon, which tend to occur on spatial scales smaller than distances between important surface observation stations, and on sub-daily (less than 24 hour) temporal scales.

A low pressure system which had originated in Alberta impacted southern Ontario on January 31st and February 1st, followed by a second low pressure system which had originally formed over Texas and Oklahoma, impacting Toronto on February 3rd and 4th. In addition to impacts to Toronto Hydro's system, power outages were also reported in Richmond Hill and Markham (Toronto Star Feb 4, 2003).

Impacts on February 1st were almost exclusively restricted to 27.6 kV equipment (except for one report), and, save for a few downed wired and tree contacts, were generally characterized generally consisted of tracking, electrical shorts and blown fuses associated with ice accretions. Beginning at around 10:30 am on February 1st through to the morning of February 3rd, several reports of electrical shorts and salt covering equipment were received, likely associated with attempts at deicing following the January 31st-February 1st storm. On February 3rd, freezing rain related reports began anew at ~5 PM and continued until 6 AM one February 4th. For this episode of severe weather, winds had been forecast to reach 70 km/h on February 3rd; maximum gusts would eventually be measured at 78 km/h (Pearson Airport) and 85 km/h at (Toronto Island Airport) the following day.

Conditions at Pearson Airport indicate that for the entire period between January 31st and February 4th the atmosphere was near or at saturation, with fog and haze being reported in conjunction with and between bouts of freezing rain, drizzle or light snow, however a total of only four hours of freezing rain were reported at Pearson Airport during that period. Temperatures crossed the 0°C boundary no less than *eight* times during this time period (**Figure C.7**).

The types of impacts, where descriptions were available, were quite different than those indicated for the December 2013 ice storm. Reports during the first portion of the event, mainly on February 1st, involved blown current limiting fuses and tracking problems. During the "break" in precipitation between February 1st and 3rd, 14 instances of *salt* related problems were addressed. Following this, a second round of precipitation, including the only reported freezing rain at Pearson Airport, combined with increasingly strong winds into February 4th, brought the first reports of galloping (mainly in Etobicoke) and only 4 reported instances of tree contacts, in addition to more blown fuses and pole top fires from icing related electrical shorts.

A *separate* storm over the Atlantic coast during the same time period, impacting the Maritimes on February 2nd and 3rd and producing 40-60 mm of ice accretion knocking out power to over 63,000 customers and causing other *very* significant damage, including roof collapses of barns and other storage buildings (EC 2003). By February 5th, 27,000 customers remained without power in New Brunswick (Toronto Star, Feb 5, 2003). The majority of repairs to the electrical system lasted for 5 days, and several locations had to be repaired twice or three times due to continued falling of ice laden trees, which was further exasperated by winds of ~75 km/h following the freezing rain (EC 2003). Massive ice accretions associated with this storm were at least partially due to the proximity of the storm to its source of moisture. Hence, while it produced similar wind speeds to the February 3rd and 4th low pressure system that affected southern Ontario, ice accretion amounts were *far* greater.

C.3.2.2 Case Study Specific Findings for January 31st-Febraury 4th

Galloping was indicated during the second storm, mainly in Toronto's west end, from what were likely a combination of ice accretions of on the order of 10 mm or less, but with winds gusting to the 70 to 80 km/h range. This is fairly close to the "15mm + 70 km/h" wind threshold indicated in previous work (CSA 2010), but may have been associated with lower ice accretion values but higher wind speeds. Additional cases would be needed to understand if galloping due to combined ice-wind loads occur in a range of wind speed and ice accretion combinations, but this case does indicate the potential for forecasting such problems when combined with monitoring of ice accretion.

Additional ice accretion, from either drizzle or light snow, coupled with several hours of reported fog or haze, is also highly likely for this event, but additional date related to this event is needed to diagnose actual accretion amounts and their causes. One should also consider that heavier precipitation may have occurred further east in North York and Scarborough, where the majority of ice accretion related impacts were reported. Indeed, several ITIS damage reports from those locations indicated ongoing snow and/or freezing rain for times when conditions at Pearson did not indicate *any* ongoing precipitation (e.g. two reports of snow in North York on the night of January 31st correspond with reports of "haze" at Toronto Pearson for the same time period). High wind and galloping conditions are likely better captured by records at Pearson Airport, since many of those incidents were reported much closer in Etobicoke.

When considering the types of impacts reported for this even, it is suggested that fog ice accretion may have slightly different characteristics than freezing rain ice accretion, which may result in slightly different impacts; i.e. when ice accretes due to fog and light drizzle in a humid environment, does it coat equipment differently than more rapidly accreting freezing rain? Did this lead to more localized problems associated with shorts and arching, in contrast to failures associated with direct physical impacts from ice loading and tree contacts? The role temperature fluctuations during and following periods of precipitation should also be investigated further. The degree of temperature variability for this event was much greater for this even when compared to the December 2013 ice storm, which again may have affected the type and degree of impacts (see **Table C.3**).

C.3.3 Large Scale Wind Storms

Large scale wind storms were identified through the Toronto Hydro Outage data for the 2000-2006 period. The maximum wind gusts reported during these storms were then compared to the number of outage events reported in the ITIS database and were also compared to the cause description, mainly identifying whether or not tree contacts were mentioned. The results of this comparison are described in **Table C.4** and illustrated in **Figure C.8**. Large scale, long duration wind events associated with low pressure systems were chosen instead of summer severe wind events associated with severe thunderstorms, since wind measurements at Pearson and Island airports were more likely to be representative of wind conditions at the damage sites for the large scale storms.

For the majority of events, a threshold wind speed of around 90 km/h emerges. A recent event on November 1, 2013, described in Toronto Hydro press releases but not well captured in ITIS, bears this out, in which 3,500 customers lost power during a wind storm which produce gusts up to 91 km/h at Pearson Airport.

It is notable that one of the most significant events, September 19, 2003 with 99 damage reports, also had the lowest reported gust at 72 km/h and is a pronounced outlier on the graph (bottom bar in **Figure C.8**), and the only other event which occurred in September shows the 2nd lowest wind speed value at 78 km/h.

To further investigate this wind speed relationship, the month of November 2005 was "back checked" to see how well a threshold of ~90 km/h was able to predict impacts to the Toronto Hydro system (**Table C.5** and **Figure C.9**). A total of 53 outage incidents were reported in ITIS for this month, with the largest number reported on November 6th and into the early morning hours of November 7th (35 reports). As indicated in **Table C.4**, these correspond with gusts of up to 89 km/h. Incidents were reported on 6 other days, with the second greatest number occurring on November 9th (9 reports). That day saw snow during the morning hours, followed by severe thunderstorm activity which resulted in one tornado in the City of Hamilton. Damage from thunderstorms is expected to be localized and therefore low wind speeds measured at Pearson airport are not surprising. The day with the third greatest number of reports also shows the second highest gust reported that month.

There are a number of potential reasons for this apparent seasonal difference between wind speed thresholds, most likely the effects of deciduous trees being still in full leaf, but, other considerations, such ground softness due temperatures remaining above freezing, must be considered given the very small sample size present here. However, data do appear indicate that threshold winds for damage increased from ~70 km/h during early fall up to ~90 km/h for late fall and winter windstorm events, and the causes listed for these impacts hint at a relationship to tree contacts.

We should mention that spring low pressure systems are also capable of producing high winds, but these do not seem to be as significant as fall season large scale wind storms. Spring severe wind storms also tend to have embedded thunderstorms, which act to further localize winds and complicate efforts to determine the representativeness of measurements. Examples of this event type include the April 20 to 21, 2000 and April 12, 2001 storms. March 9-10, 2002 is the only significant spring wind storm in the 2000-2006 period, but this event was also accompanied by severe thunderstorm activity which produced much more significant impacts in other parts of Ontario, including the loss of multiple Hydro One electrical transmission towers.

C.3.3.1 Superstorm Sandy: October 29-30, 2012

So-called "Superstorm" Sandy, responsible for major devastation in several major east coast cities in the United States, also produced impacts in Canada, including one fatality from windblown debris. Toronto Hydro estimated about 60,000 customers had lost power during the storm (T.H. Press Releases, Toronto Star 2012). Adjacent LDE Enersource reported approximately 6,000 customers lost power during the event, with 6 crews beginning restoration efforts at around 6PM on October 29th (Mississauga News 2012). Causes for these outages included the loss of three hydro poles. ORNGE air crews had also been grounded at 2 pm October 29th due to high winds (Toronto Star 2012).

Toronto Hydro had been initially criticized for not immediately declaring Level 3 status for this event and beginning repairs; however, the vice president of grid management indicated attempting repairs during the storm would have been futile and dangerous for repair crews (Toronto Star 2012). "There's nothing we could have done between 2 am and 6 am." Press releases issued as early as 6 PM on October 29th warned customers that repairs may be impossible during high winds.

A map depicting impacts and rainfall measurements for the event is provided in **Figure C.10**. Unfortunately, outage incident data appears to be incomplete for this time period (the event having occurred after 2006), and media reports for the city of Toronto lack specific damage and failure location descriptions. This is in sharp contrast to media reports from the City of Mississauga (Mississauga News 2012), the source of all media damage reports indicated in **Figure C.10**.

With the exception of one incident, wind damage reports from ITIS all appear in the southern half of the City of Toronto, and these also correspond very well with media reports of wind damage in Mississauga, as well as the difference in measured severity between Pearson (80 km/h max gust) and Toronto Island (91 km/h). There are simply too few available rain related damage reports to determine if important thresholds were reached for direct overland flooding related damage, and a comparison between Buttonville and Pearson to determine if antecedent rainfall played an important role appears to be negative. Both areas experienced similar amounts of antecedent rainfall on October 28th, followed by wind gusts of similar magnitudes on October 29th; however, only areas located southwest and southeast of Pearson reported any notable wind damage.

Toronto Hydro press releases, including those issued as early as 9:30 PM on October 29th, before the peak of the storm, in indicated trees and tree limb contact with overhead wires as the main cause of the outages (T.H. 2012). The October 30th 10:39 PM press release specifically indicated, "Toronto Hydro estimates that more than 85 per cent of outages were caused by tree contacts with power line[s]" Further indicating that repairs are expected to exceed $1 million and that other jurisdictions, which have far less tree cover, were not expected to be as heavily impacted. On the evening of October 30th, the worst affected area was roughly bounded by "Talwood Drive (north), Eglinton Ave E (south), Bayview Ave (west) and Don Mills Rd (east)"

The preponderance of tree and tree related damage in the southern portions of Toronto and Peel, coupled with the transition from wind gust regimes from 80 km/h to 90 km/h, further supports the findings from the analysis of large scale wind storms indicating wind speed thresholds of 90 km/h, again likely related to tree contacts. Budget and time limitations prevent further analysis of this event (e.g. search for impacts in Durham region) for the time being, but further research is strongly indicated.

C.4 Severe Summer Thunderstorm Events

C.4.1 July 8, 2013 Extreme Rainfall Event

"Little India resident Kurt Krausewipz, said the 'thick heavy sheets of rain,' reminded him of monsoon season in Southeast Asia." (Toronto Star, July 9, 2013)

The flash flood event on July 8th, 2013 was responsible for the largest 24 hour rainfall amount ever reported at Pearson Airport. The event was notable for a number of important impacts, including the stranding hundreds of GO transit commuters for 5 hours on a flooded train in the Don Valley (Toronto

Star, July 9, 2013), as well as an eventual tally of nearly $1 billion in insured damages (CBC.ca 2014), mainly resulting from basement flooding. It also resulted in a significant power outage event for Toronto Hydro, with approximately 300,000 customers losing power for several hours[5] (Toronto Hydro Press Release, July 9, 2013). The outage event was mainly triggered by the failure of critical infrastructure located below grade[6] at two transformer stations linking Toronto's distribution system with Ontario's electrical transmission system.

To understand the magnitude of the event, and to assist with developing a threshold for this type of failure, maps depicting rainfall amounts across the city (Cole Engineering Group, 2013) were compared with media reports of damage, as well as the locations of the two transmission stations which suffered failures during the event (Hydro One, 2014). See **Figure C.11** for station locations relative to rainfall accumulation amounts.

The extreme rainfall event began around 4 PM and produced eventual failures at Manby and Richview transformer stations, with Hydro One declaring a "Level 2 Transmission Emergency" (Hydro One 2014). Both are located within and near the area of greatest rainfall accumulations recorded for the event, located roughly along and on either side of the Etobicoke-Mississauga border (Cole Engineering Group, 2013). A rainfall total of 126 mm was reported at Pearson International Airport, with a maximum 1 hour total of 74 mm (EC 2014); however, this was roughly within the western edge of what municipal rain gauge networks indicate as a "bull's-eye" centered slightly E of Pearson International, which contained accumulations of over *130 mm* of rain (Cole Engineering Group, 2013). Richview TS is located in the *immediate center* of this area of extreme precipitation. Manby TS is located several kilometers to the south and was subject to far less rainfall in its immediate vicinity, located nearly on and just north of the 80 mm rainfall contour. It is not clear how much additional flooding at Manby TS was the result of runoff from areas further north, or if the design and characteristics of Manby TS may have made it more vulnerable to flooding than other stations. Hydro One's system officially returned to "normal" status at 2:44 PM July 15th (Hydro One 2014).

"Level 2 remained in effect until 5:34 p.m. on July 12th as Hydro One worked to reinforce the system with restored transmission connections between Richview TS and its remote terminal stations: Trafalgar TS, Cherrywood TS, Parkway TS and Claireville TS. This provided redundant supplies and vastly improved network security." (Hydro One, 2014)

It is notable that stations located near a secondary maximum over downtown Toronto (particularly Leaside TS), did not suffer the same impacts as Richview and Manby. Rainfall in the core of the downtown maximum approaching 100 mm. Toronto's climate station at the U of T campus reported 96.8 mm of rain (EC 2014), but Leaside TS is located approximately 3-4 km to the NW of the core of this

[5] In contrast to the Dec 2013 ice storm, however, the nature of the failures allowed for ~90% restoration for distribution customers by the early hours of the following morning (TH Press Release, July 9, 2013).
[6] Interviews by RSI with practitioners at the OPA for the "sister" transmission case study indicated that placement of critical infrastructure in below grade locations may have also played a critical role in the failures experienced in this case.

much smaller maximum subject to an estimated 65-70 mm rainfall, and was also not "down-stream" from another maximum as was the case for Manby TS.

Rainfall data from Pearson International also indicate possible antecedent rainfall conditions, since 26.6 mm of rain were recorded on July 7th, the day prior to the event, and a total of 31.4 mm of rain was recorded in the full week prior to the rainfall event (EC 2014). Similarly, Toronto's downtown climate station reported 38.1 mm of rainfall on July 7th and a total of 48 mm during the week preceding the July 8th flood.

"Since June 1, downtown has seen 165 mm of rain, about double the average of 87 mm." (Toronto Star July 9, 2013)

As with the Superstorm Sandy case, outage data appeared to also be lacking in the ITIS data, with only one listing indicated for this event. However, the clear cause in this case was the direct impact to transmission infrastructure, reducing the need for similar analyses conducted for other cases in which outage causes were more local and directly related to physical impacts to the distribution system.

C.4.1.1 Case Specific Findings July 8th Flood

Rainfall in excess of 100 mm in less than 24 hours, and indeed within the span of only a few hours, appears to have been required to cause the types of failures experienced at the two western Toronto stations. Antecedent rainfall may have also played a role in the flooding, generating more runoff than would have otherwise occurred. Topography and associated runoff patterns may have also played a role, particularly for Manby TS, but conclusive evidence of this would require further investigation.

This may also be a case of extreme rainfall rates under the "sub-daily" category, given that both this case and August 19, 2005 saw the majority of rainfall occur within a few hours, with a majority of the total 24 hour rainfall occurring within approximately *one* (1) hour. Extreme rainfall rates should be directly correlated with runoff efficiency and design requirements (e.g. pumping rates for mitigation, flash flood peaks, etc.) and may be important in determining how such events generate severe impacts to these systems.

While the main infrastructure that failed was indeed owned by Hydro One, these findings have direct implications of great importance to Toronto Hydro Infrastructure. Toronto Hydro was still directly and severely impacted by the failure of 3rd party infrastructure. The PIEVC process includes 3rd party infrastructure among the needed elements for review and consideration, and this is particularly relevant for the highly interconnected electrical grid as a whole. While this was not the case in this particular event, similar infrastructure owned by Toronto Hydro may be susceptible to extreme rainfall conditions. These locations and infrastructure elements should be explicitly identified and evaluated for their vulnerability.

C.4.2 August 19, 2005 Finch Washout Event

A large "supercell" thunderstorm produced significant impacts across a swath of south-central Ontario on August 19, 2005. Perhaps the most well-known and publicized impacts from the event consisted of the complete washout of a section of Finch Avenue at Black Creek in North York. In addition to this, however, there were numerous reports of basement flooding in Toronto and York region, several vehicles being swept off of roads or submerged, in addition to several thousand homes in Toronto suffering power outages, mainly in Etobicoke and Scarborough areas (Toronto Star, August 20th, 2005). The specific causes for these outages were not provided by media reports, however ITIS incident reports, coupled with the location of reported damage, indicate that outages were mainly related to flooding. Preceding the impacts in the GTA, the supercell storm produced two large, F2 tornadoes west of the city in the Listowel and Fergus areas, severely impacting farming and cottage communities.

A map of reported impacts is provided in **Figure C.12**, combining ITIS and media damage reports with meteorological measurements for comparison. A fairly clear pattern emerges in which a corridor of extreme rainfall with embedded amounts in excess of 100 mm corresponds quite well with the majority of extreme rainfall related outage incidents, indicated by red and orange circles superimposed with an “X” in a band extending from central North York ESE to Scarborough. Extreme rainfall amounts to the immediate north of Toronto were also associated with significant basement flooding in York region. A second more isolated patch of extreme rainfall may be indicated in north Etobicoke, but could also be illusory due to the suspect reading (only 24.7 mm) located north of the Finch Washout.

Interestingly enough, tree contact and wind related damage reports are generally located south of the corridor of extreme precipitation; this is consistent with the storm type. While impacting Toronto and the GTA, the storm produced a swath flooding rainfall and large hail under as a core of heavy precipitation tracked across the city, while winds gusting to ~70 km/h or more were present *south* of this core and were responsible for several minor tree contact related damage reports[7]. A comparison between wind measurements at different locations, however, could not be conducted, as wind gust data are not available for this date for Toronto’s Island airport.

C.5 Extreme Heat Days

While it is generally common knowledge that during hot and humid days during the summer, air temperatures are much cooler along the shores of Lake Ontario than they are in other parts of the city, the potential impact this temperature difference may have on electrical system response is not often considered.

Table C.6 provides a comparison between three stations to determine temperature differences across the City of Toronto on days in which high heat impacts on the distribution system were indicated (see **Table C.2** for greater details). These stations are located on or very near the western, southern and northern boundaries of the City of Toronto and provide an excellent measure of the temperature differences experienced across the city. Temperature differences of between 2.6 and 5.7 degrees are evident, while the locations of impacts strongly indicate a preference for impacts to infrastructure in Etobicoke. The number of incident reports appear to be correlated to the maximum temperature, although sample size is extremely small. The average temperature difference between Pearson Airport

[7] Had the storm produced a tornado while over the city, it would have been located at the southern edge of the heavy precipitation core. Luckily, the storm changed characteristics when approaching the GTA and appears to have been no longer tornadic when impacting the area.

and Toronto Island Airport is 4.1 degrees for the four high heat days, and the difference between North York Climate Station and Toronto Island is slightly less at 3.1 degrees.

Figure C. 13 shows an example of a high heat day (July 16, 2006) in which impacts began to be reported in North York at two different transformer stations. Interestingly enough, two of the four reports are listed as “Adverse Weather/Tree Contacts”, and we are unsure of the nature of these reported causes. Either they have been mistakenly coded, or tree contacts may have occurred due to line sag, but details on the specific impact characteristics are lacking. The small number of reports indicated in North York for this date and the inter-comparison in **Table C.6**, coupled with results from the literature review and discussions with practitioners, provide additional evidence that negative impacts to the distribution system begin to appear as temperatures approach ~35°C.

This case, however, provides an excellent example of the temperature gradient often present across the City of Toronto during extreme heat days, with slightly higher temperatures occurring further from the lake. During the summer, the temperature difference between land and lake often result in the production of a lake breeze, in which cooler, heavier air over the lake flows inland, the leading edge of that air often acting as a miniature cold front. This can result in notable temperature gradients across the city, and can also trigger and/or enhance thunderstorm activity at the boundary between lake air and air further inland.

Although time and resources did not allow for more detailed assessment, a greater number of days in which extreme heat impacted the Toronto Hydro distribution system should be further investigated to help refine this threshold further. Further analysis is also needed to ensure that the impacts of other air mass boundaries (i.e. large scale fronts) are not skewing the results presented here, as similar temperature gradients can be produced through other mechanisms unrelated to the effects of the lake.

C.6 Final Conclusions

In summary, the forensic analyses resulted in the following conclusions:

- Although data sufficiency and time allotted to the project prevented the thorough investigation of many of the events identified through this forensic analysis, several avenues of future research were identified which could lead directly to improved operational maintenance and management measures, including improved forecasting of climatic impacts to assist in anticipation and preparation for significant events.
- In some cases, it was clear that Toronto Hydro operations and maintenance crews were making effective use of forecasts to help plan and optimize repair and response, such as allowing severe weather conditions to pass before full repair operations were initiated.
- In most cases, and particularly for those in which localized differences in impact severity were evident, further analysis was stymied by a lack of observational data. Even with the inclusion of additional observational data provided by TRCA (2014), spatial gaps in observations prevented the assessment and diagnosis of conditions in certain locations (e.g. December, 2013 ice storm

damage in Scarborough lacking ice accretion or temperature measures; August 19, 2005 severe thunderstorm wind speed measurements in southern portions of the city).

- The majority of power outage events identified in the 2000-2006 period were extended events lasting up to 48 hours, representing the need for sustained operational response, but the characteristics of these events differed depending on season:
    - Extended warm season events consisted of 2 or more acute weather events in quick succession, and were a combination of related hazards producing impacts (e.g. extreme heat followed by thunderstorm activity)
    - Cool season and shoulder season events tended to last several hours; when storms occurred in succession, they tended to be separated by periods of one or more days
    - The years with the greatest reported impacts to the distribution system were characterized by multiple moderate to major outage events occurring in different seasons (e.g. significant severe thunderstorm event during the summer followed by one or more wind storms during the fall season)
- Thresholds determined for wind speed and ice storm damage agree well with previous work and research, and these also appear to be *directly* related to tree contact related impacts rather than direct climatic loading of infrastructure through wind or ice accretion.
    - The 70 km/h threshold for wind gusts, originally provided by Toronto Hydro staff during Phase I, appears to be correlated with tree damage, particularly during the warm portions of the year when deciduous trees are in full leaf, resulting in secondary impacts to the distribution system; further research is needed to confirm this relationship
    - The 90 km/h threshold appears to be both related to the baseline climatic loading used in design of civil infrastructure components (see CSA 2010) as well as tree damage after deciduous trees have shed their leaves
    - The lower bound of 15 mm for freezing rain totals resulting in tree contacts with overhead systems agree well with the findings from Klaassen et al. (2003)
    - Freezing rain totals of less than 15 mm, however, may cause impacts when combined with high humidity environments near the 0°C boundary. This can specifically result in flashovers and other related impacts. While not as severe as direct damage to overhead lines and other equipment, these types of impacts can be numerous, widespread, and localized, presenting particular challenges for restoration efforts
- Overall, larger metropolitan LDCs appear to be more vulnerable to climatic events than smaller LDCs, particularly when considering overall restoration times; this is likely due a culmination of factors, not the least of which include the state and age of equipment, difficulty of access for system repair in an urban environment, and the relative proportion of staff available with respect to total number of customers and the size of a geographical area of responsibility.
- Certain regions within the city appear to be more susceptible to weather related power outages; potential regional differences in vulnerability should be investigated further. It is not clear at this time if these vulnerabilities are due to aging infrastructure, proximity to aged canopies, difficult to access infrastructure (e.g. back-lots) or some other combination of factors.

- There were several cases in which events tended to follow one-another in series, with either the restoration following a major event being hampered by subsequent smaller events, or several moderate events resulting in prolonged, multi-day outage cases where new damage occurred immediately following recovery from previous events
- Extreme rainfall impacts are worst with warm season severe thunderstorms. These were characterized by highly localized events impacting only a portion of the City, generating rainfall accumulations of over 100 mm, the majority of which (>50%) falling on during a period of *one hour*. Rainfall impacts with longer the longer duration, larger scale events investigated here (e.g. "Superstorm Sandy") appeared to be minor.
- Changes in tree health conditions such as disease and pests may also be playing a role in increasing sensitivity to damage, as suggested by analyses of the December 2013 ice storm. These represent very complex interactions, since the extent of certain disease and pests will also be affected by changing climate regimes, and their interaction with the structural integrity of trees and limbs is still unknown.
- Even for winter events, which are ostensibly much less localized in nature than warm season storms, localized differences in infrastructure impacts were evident, and without additional data, the causes for these disparities were not entirely clear. In one case (December 21-22, 2013) a small scale weather feature was explicitly identified as having very likely been a major contributor to the case overall, and similar findings are expected if similarly in-depth analyses are conducted of other high impact winter storms.
- Differences in impacts due to storm structure and other localized meteorological factors were evident in some cases (e.g. separation of precipitation and wind related impacts Aug 19, 2005). While these are to be expected, they may also assist in response to events when combined with remote sensing data, such that response crews may be better informed as to the type of impacts they may encounter following a severe storm.
- Events were not only characterized by impacts to the distribution system, but tended to consist of multiple, often severe impacts to other buildings and infrastructure, including transportation, and communication infrastructure. These impacts compounded effects on the distribution system by further complicating operational response.
- Smaller events which barely generated more than 20 damage reports, such as July 1, 2001 (lightning and rainfall) or April 28, 2002 (high winds), should be studied to understand where the lower damage thresholds may lie and/or which areas within the city or infrastructure types/categories are the *most* vulnerable
- The presence of Lake Ontario directly impacts the behaviour of certain weather hazards, generating differences in risk across the city; it generally moderates temperatures, warming areas adjacent to the lake during the cool season and cooling areas near the lake during the summer. This effect either mitigates or exacerbates the severity of hazards depending on the type of hazard (e.g. areas downtown are kept cooler during extreme heat days, but the leading edge of the lake breeze also plays a role in enhancing severe thunderstorm hazards for other portions of the city).

- The interconnectivity of Ontario's electrical grid is vital to understanding the potential impacts from atmospheric hazards; coordination between transmission providers and LDCs in risk assessment analyses may be *pivotal* in understanding and addressing these risks.

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Table C.1: Events subject to detailed investigation.

Date(s)	**Event Hazard Type(s)**
January 31st to February 4th, 2003	Multi-day ice accretion event; complex interactions
August 19, 2005	Flash flooding; lightning, some winds (tree contacts)
July 16, 2006	Extreme Heat; threshold/borderline event
October 29-30, 2012	Superstorm Sandy; winds, possible rainfall impacts
July 8, 2013	Flash Flooding; failure of 3rd party underground infrastructure
December 21-22, 2013	Ice Storm; mainly tree contacts

Table C.2: Toronto Hydro Events Outage Events 2000-2006 with *20 or more* incident reports.

Medium to High Impact Events T.H. Failure Database	Event Type	Number of Reports
February 23 to 25, 2000	rain and snow	49
February 3 to 4, 2000	freezing rain	37
February 16, 2000	snow and freezing rain	72
4/20/2000 and 4/21/2000	high winds and rainfall	42
May 12 to 13, 2000	wind, rain and lightning	157
6/14/2000 and 6/15/2000	lightning and "adverse weather"	58
14-Jul-00	lightning	121
7/17/2000 and 7/18/2000	lightning, some high winds, extreme heat	88
5-Jan-01	snow	28
12-Apr-01	high winds	33
1-Jul-01	rain and high wind	21
4-Jul-01	rain, lightning, and wind	21
7/22/2001 and 7/23/2001 and 7/24/2001	lightning	53
8/7/2001 to 8/9/2001	heat and humidity	72
25-Oct-01	high winds	20
1-Feb-02	high winds	29
March 9 to 10, 2002	"adverse weather"	78
28-Apr-02	high winds, rain	21
7/21/2002 to 7/22/2002	lightning, some heat and humidity	107
9/20/2002 to 9/21/2002	rain and lightning	23
1/31/2003 to 2/1/2003	snow and freezing rain	155
2/3/2003 to 2/4/2003	freezing rain	71
5/5/2003 and May 6, 2003	lightning	45
8/21/2003 and 8/22/2003	lightning, high winds and rain	58

19-Sep-03	high winds	**99**
10/15/2003 and 10/16/2003	high winds	**81**
11/12/2003 and 11/13/2003	high Winds	**80**
4-Jul-04	lightning, rain	**43**
23-Dec-04	Freezing rain	**27**
2/6/2005 and 02/07/2005	fog	**25**
6/13/2005 and 6/14/2005	lightning, some "tree contacts"	**42**
28-Jun-05	lightning	**30**
4-Jul-05	lightning, some wind and rain	**68**
July 11 to 12, 2005	heat and humidity	**39**
8/19/2005 and 8/20/2005	extreme rainfall, high winds and lightning; DETAILED ANALYSIS	**162**
29-Sep-05	high winds	**42**
6 to 7-Nov-05	high winds	**35**
2/17/2006 and 2/16/2006	high winds	**49**
31-May-06	lightning	**24**
6/28/2006 and 6/29/2006	lightning, rain extremes	**88**
10-Jul-06	rain, lightning	**24**
7/17/2006 & 7/18/2006	lightning, heat and humidity, some wind	**66**
8-Sep-06	rain, lightning	**24**
10/4/2006 and 10/3/2006	lightning and high winds	**30**
29-Oct-06	high winds	**28**

Table C.3: Comparison of ice accretion events with reported impacts.

Dates	Estimated Total Ice Accretion	Total # Hours **Freezing Rain** and Drizzle	Impacts
January 31-February 4, 2003	Est. ~10-12 mm (difficult given complex temperature regime and multiple	**Pearson: 4 hours (Feb 3rd);** no freezing drizzle reported, but snow, drizzle, fog and haze reported at various times	Most damage from shorted and blown fuses, tracking, few downed lines, galloping during high winds following 2nd period of precipitation; high humidity and multiple

	precipitation types)		temperature changes about 0°C
December 20-22, 2013	Est. <15 mm Downtown Toronto to 25-35 mm York and Durham Regions	**Pearson: 4, 16 and 6**, and 2, 5 and 10; **Buttonville: 8, 13 and 8**,and 1, 5 and 10; Total hours for December 20th, 21st, and 22nd, respectively	Mainly due to tree impacts, greater periods of temperatures above 0C and liquid precipitation for locations closer to downtown Toronto, significantly reducing ice accretion totals for full 3 day period

Table C.4: Comparison of highest wind gusts with large scale outage events.

Date	**Peak Measured Gusts (km/h)**	**Cause Description**[8]
25-Oct-01	Pearson: 91; Toronto Island: 82	Tree contacts 8/20
19-Sep-03	Pearson: 72; Toronto Island: 80	Tree contacts 32/99; other causes included “driving rain”, “auto reclose” of breaker due to high winds
15 to 16-Oct-03	Pearson: 91; Toronto Island: 89	Tree contacts 30/81; remainder mainly “high wind/adverse weather”, one report of “fuse fell open in high wind”
12 to 13-Nov-03	Pearson: 93; Toronto Island: 96	Tree contacts 16/64; remainder simply indicated as “high wind/adverse weather”, some lightning
29-Sep-05	Pearson: 78	Tree contacts 28/42, rest related to high winds, including broken insulator
6 to 7-Nov-05	Pearson: 89	Tree contacts 13/35
16 to 17-Feb-06	Pearson: 91	Tree contact: 8/13 (16th) & 12/34 (17th); also some freezing rain reported on both dates, remaining[9] were generally listed as high winds, incl. one broken insulator
29-Oct-06	Pearson: 96	Tree contact: 12/28 reports
1-Nov-13	Pearson: 91	Tree contacts: 3/7 reports

Table C.5: Comparison of *all* impact reports for November 2005 to maximum gust speed.

Date	Gust Speed (Pearson Airport)	**Number of Reports**; Notes
Nov 6th	89	**35**; 2 early morning Nov 7th, considered same event
Nov 9th	59	**9**; same day F1 Tornado, Hamilton, ON; morn report include

[8] Tree contacts were counted both when coded as cause, as well as cases where cause was coded as “adverse weather” but description of impacts indicated tree contacts were responsible.
[9] One report of a “temperature extreme” causing a failure at -3°C ambient temperatures appears to be a coding error.

		snow, thunderstorms mid-day and evening, wind caused limbs on wires 3 reports, lightning related outages 3 others
Nov 11th	35	**1**; rain indicated as cause
Nov 16th	83	**4**; three high wind reports, one "no cause", "switch fell open"
Nov 17th	59	**1**; large tree on line, rain indicated
Nov 24th	78	**2**; winds indicated as cause, possible duplicate report of one incident
Nov 25th	48	**1**; conditions indicated as "clear" no specific cause given

Table C.6: Comparison of maximum temperatures (°C) for high and extreme heat days.

Date	Impacts (# heat related reports)	Pearson Airport	Toronto Island Airport	North York Climate Station
July 17, 2000	Minor; only 2 in Etobicoke	28.6	24.4	27.0
Aug 8, 2001	33 total; 18 in Scarborough, 10 Etobicoke	37.9	34.7	37.5
July 11, 2005	19 total; 10 Etobicoke, 7 North York	35.5	29.8	34.0
July 12, 2005	18 total; 7 Etobicoke, 7 North York	34.7	31.4	34.5

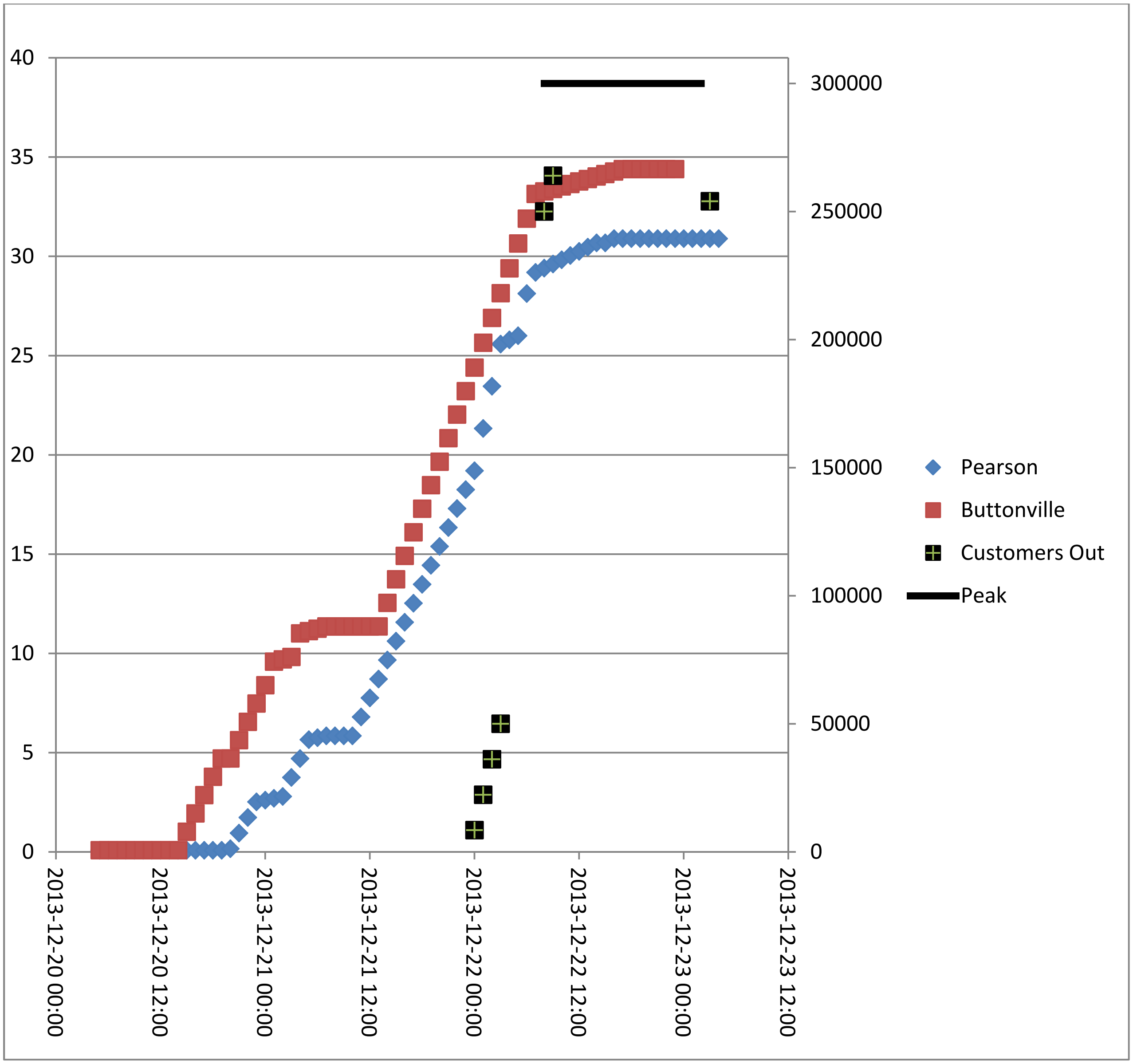


Figure C.1: Estimated ice accretion rates using observations at Pearson and Buttonville Airports. Peak outages (300,000 customers) is represented a long black bar since the exact time period in which this number of customers were without electrical service was not given and indeed may not be known.

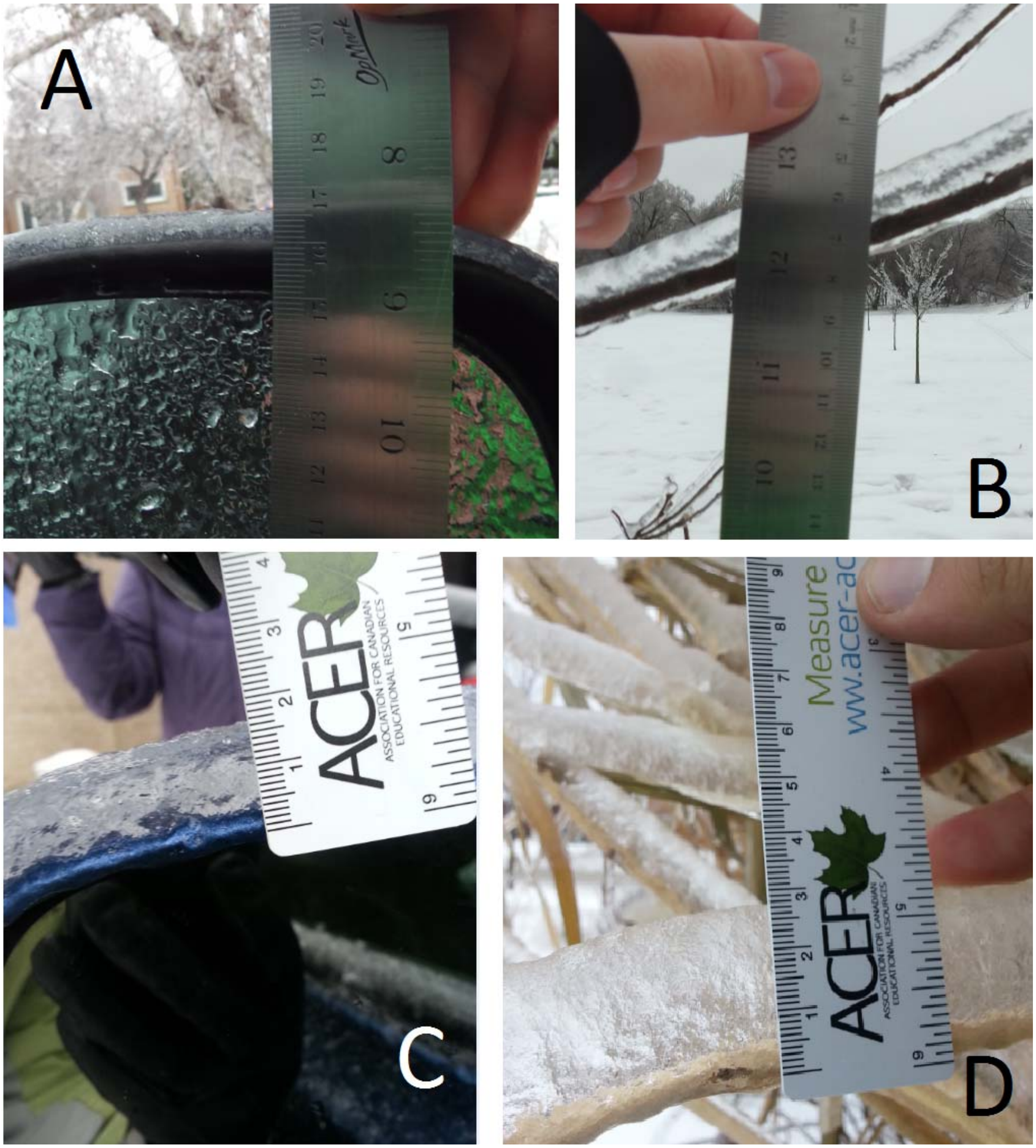


Figure C.2: Ice accretion measurements on similar objects are compared between locations in central Etobicoke (A and B), located ~5 km SE of Pearson airport, and Richmond Hill (C and D), ~9 km NW Buttonville Airport. Ice accretions on car side mirrors are measured at 6 and 15 mm and for branches of similar diameter at 10 and 23 mm, for Etobicoke and Richmond Hill locations, respectively. While measurements are not exactly equivalent in terms of exposure and accretion surface and shape characteristics, they do provide evidence that ice accretion amounts were appreciably higher for municipalities north of the City of Toronto in comparison to locations near Pearson Airport. Photos by RSI team members H. Auld (Thornhill) and S. Eng (Etobicoke).

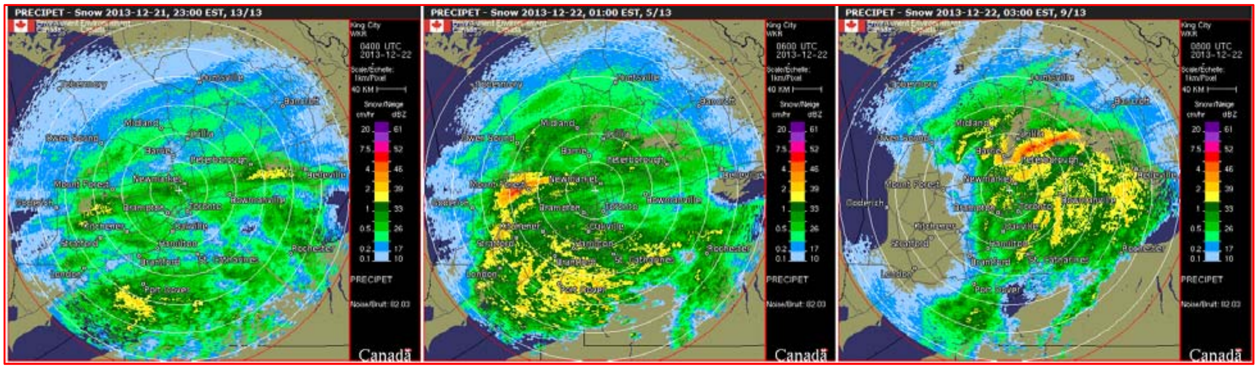


Figure C.3: King City radar imagery; panel times (left to right)correspond to 11 PM December 21st, 1 AM December 22nd and 3 AM, December 22nd, 2013. A small scale meteorological feature appears to have been responsible for an area of particularly heavy precipitation which tracked across the GTA in early morning hours, corresponding with the highest ice accretion rate estimates for the entire event.

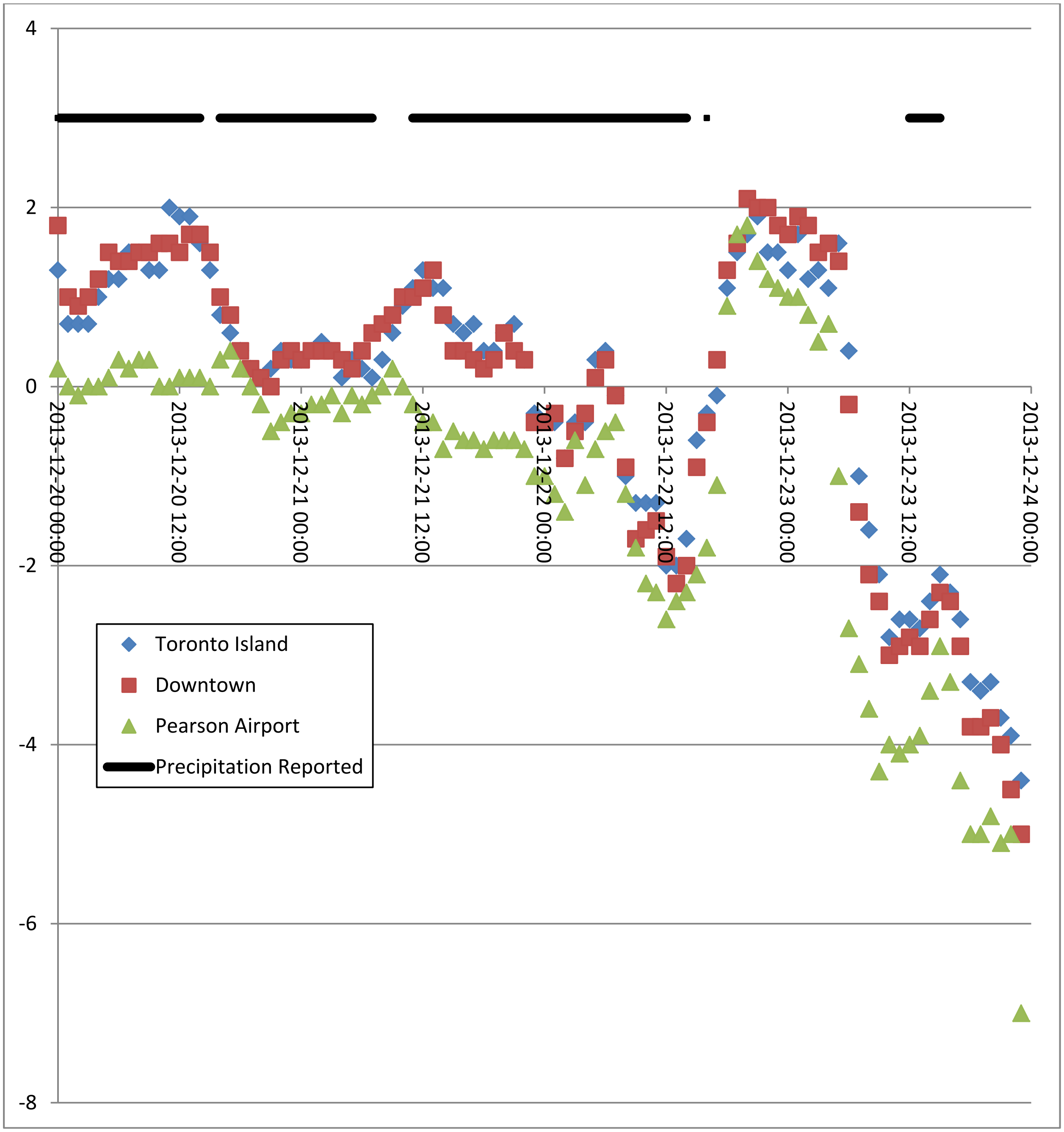


Figure C.4: Comparison of hourly temperatures between Pearson International Airport and stations located in downtown, accompanied by hours with reported precipitation. It is likely that precipitation occuring before 11 PM on December 21st did not contribute to any important ice accretion, but still resulted in significant impacts to many neighbourhoods in and around the downtown core.

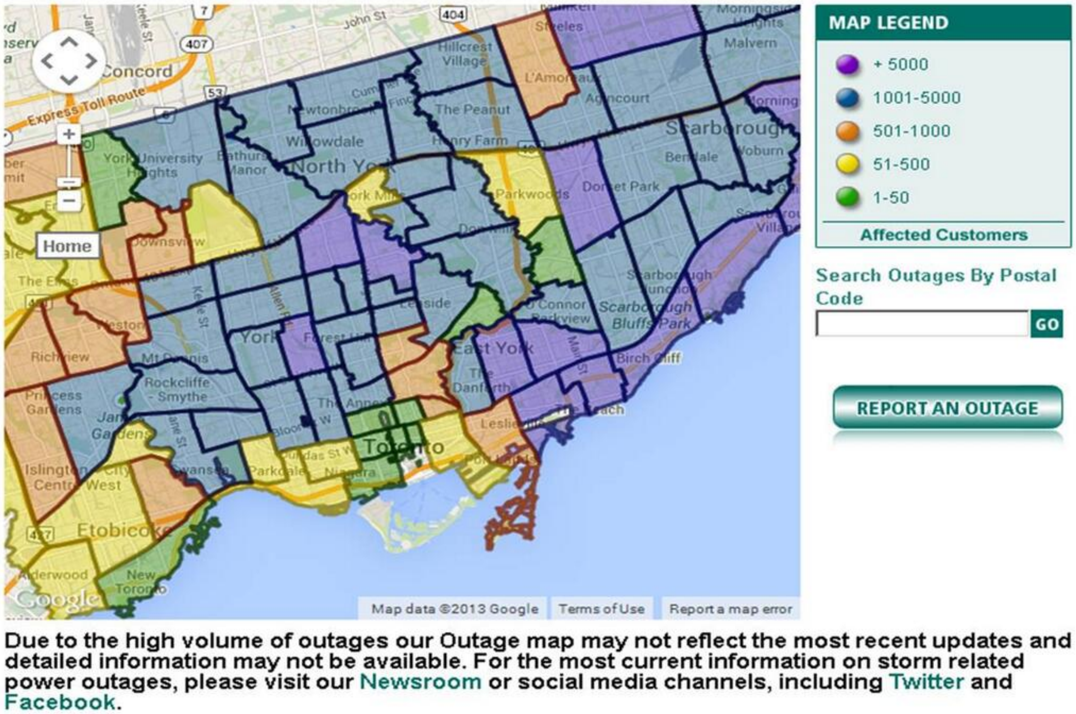


Figure C.5: Toronto Hydro outages map valid for 11 AM December 23rd. Note clear boundaries to north of Bloor and east of Woodbine/Don Valley. Unfortunately, both detailed impacts data and meteorological observations prevent better diagnoses of causes for these differences in system response to the event for areas like East York and Scarborough. Image retreived 11:50 AM December 23rd, 2013.

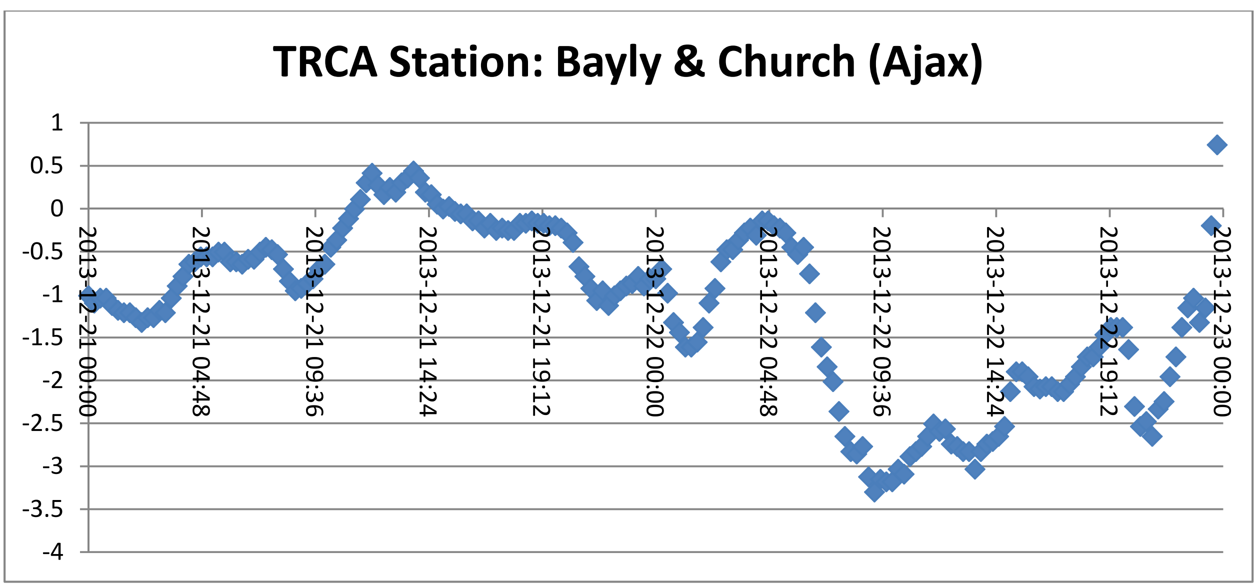


Figure C.6: Temperature Data from Bayly and Church in Ajax. When considered in conjunction with temperature and precipitation measurements from Oshawa Airport, these temerpatures indicate likelyhood that the majority of precipitation experienced between December 21st and December 23rd was in the form of freezing rain, suggesting ice accretions in Ajax were likely similar to other portions of Durham Region. Data courtesy of Toronto Region Conservation Authority.

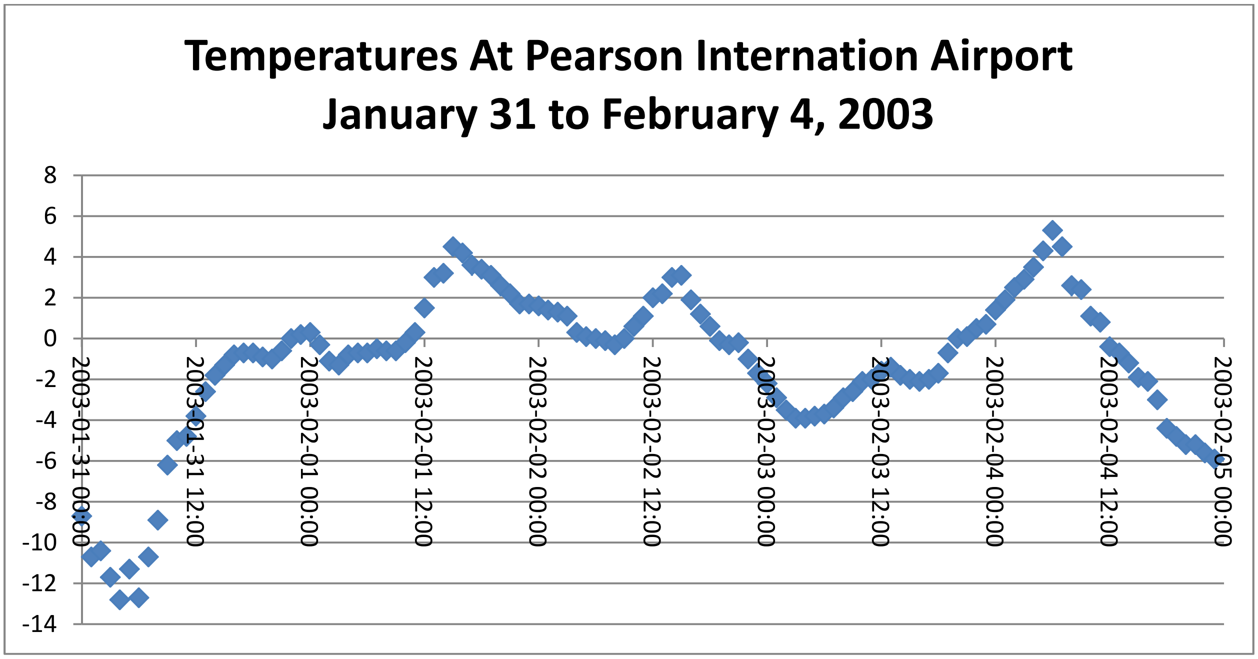


Figure C.7: Hourly temperatures at Pearson Airport between January 31st and Febraury 4th, 2003, corresponding with a complex winter event that produced a total of 160 incident reports as well as outages for over 50,000 Toronto Hydro customers. Temperatures "crossed" the 0°C line no less than 8 times during the 5 day period of unsettled weather.

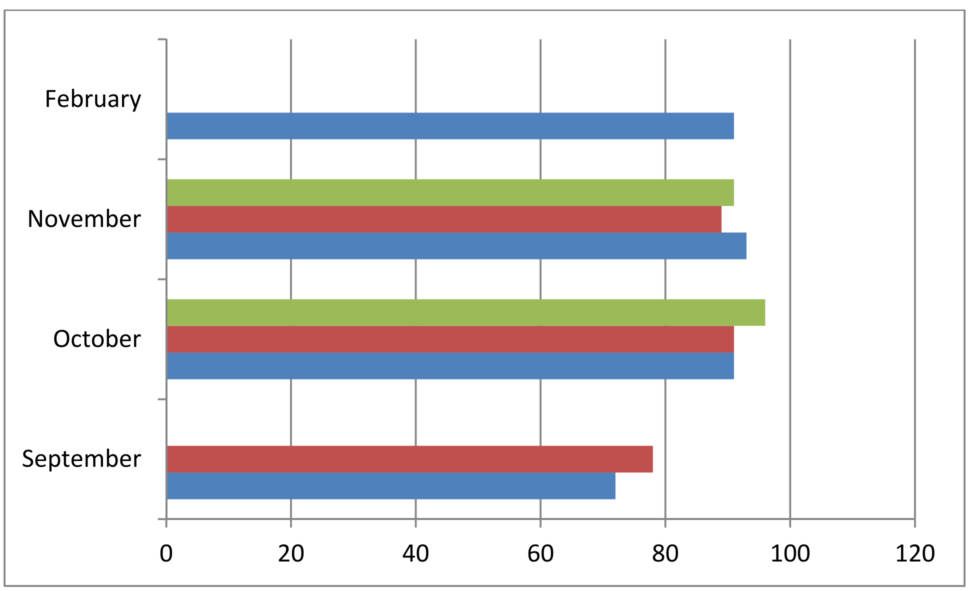


Figure C.8: Max gusts for outage events plotted by month indicate a potential relationship which deserves further study.

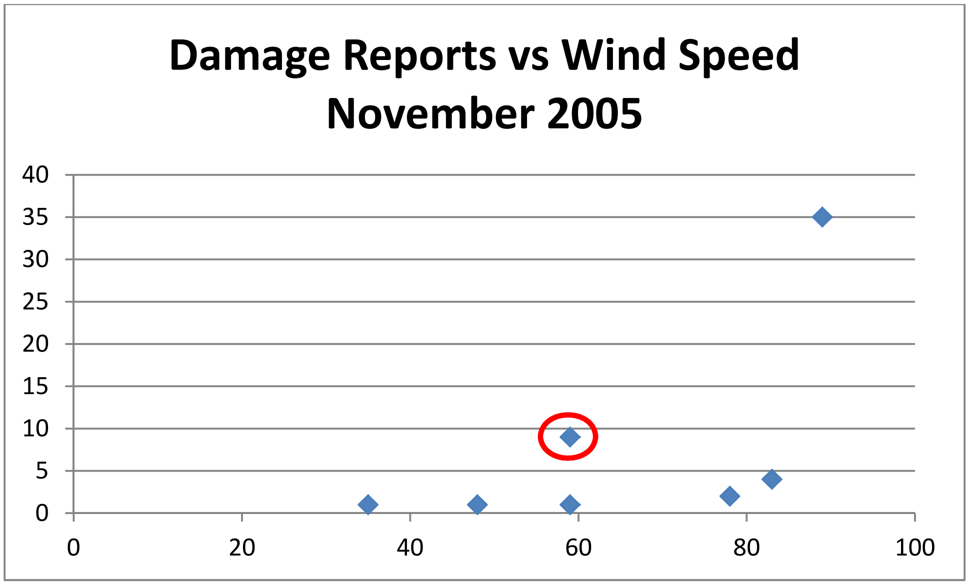


Figure C.9: Number of reports versus max gust reported for November 2005. Note the one apparent outlier, circled in **red**, is November 9th, in which localized impacts are expected and conditions at Pearson Airport are expected to be less representative of conditions producing impacts at a given site.

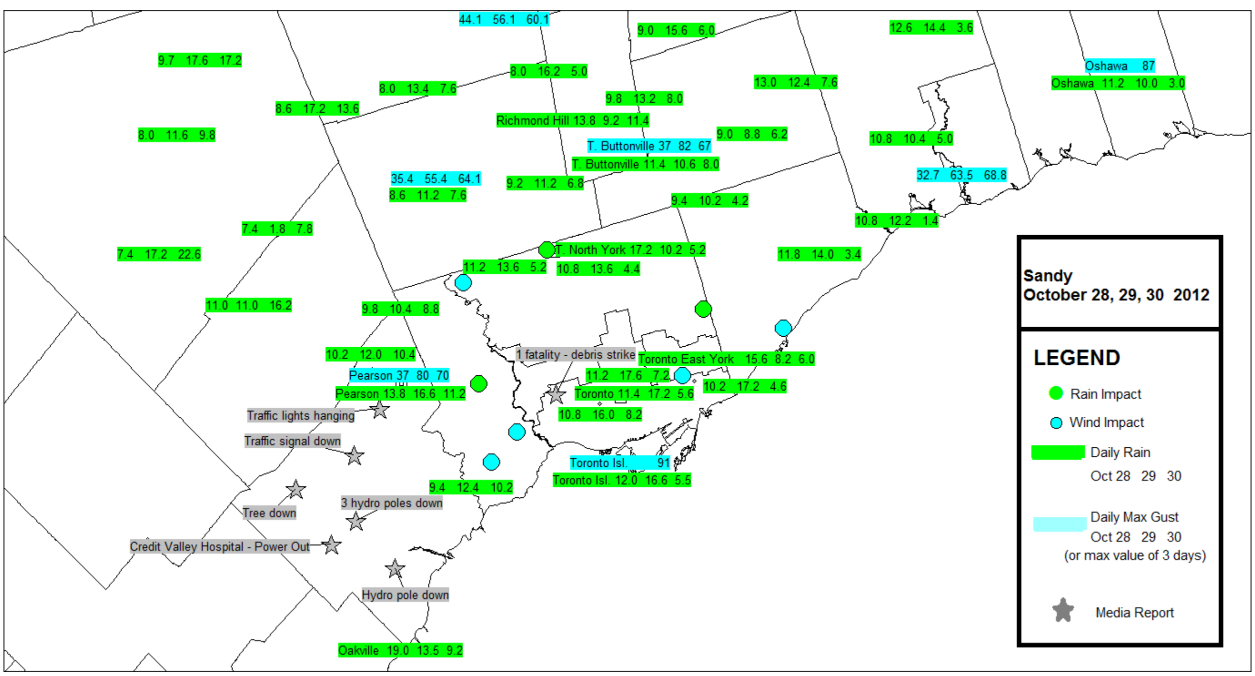


Figure C.10: Map comparing reported impacts with meteorological data for "Superstorm" Sandy. Meteorological data are for October 28th, 29th and 30th and help illustrate the progression of events. Precipitation and wind values are a combination of both EC and TRCA (2014) observational data.

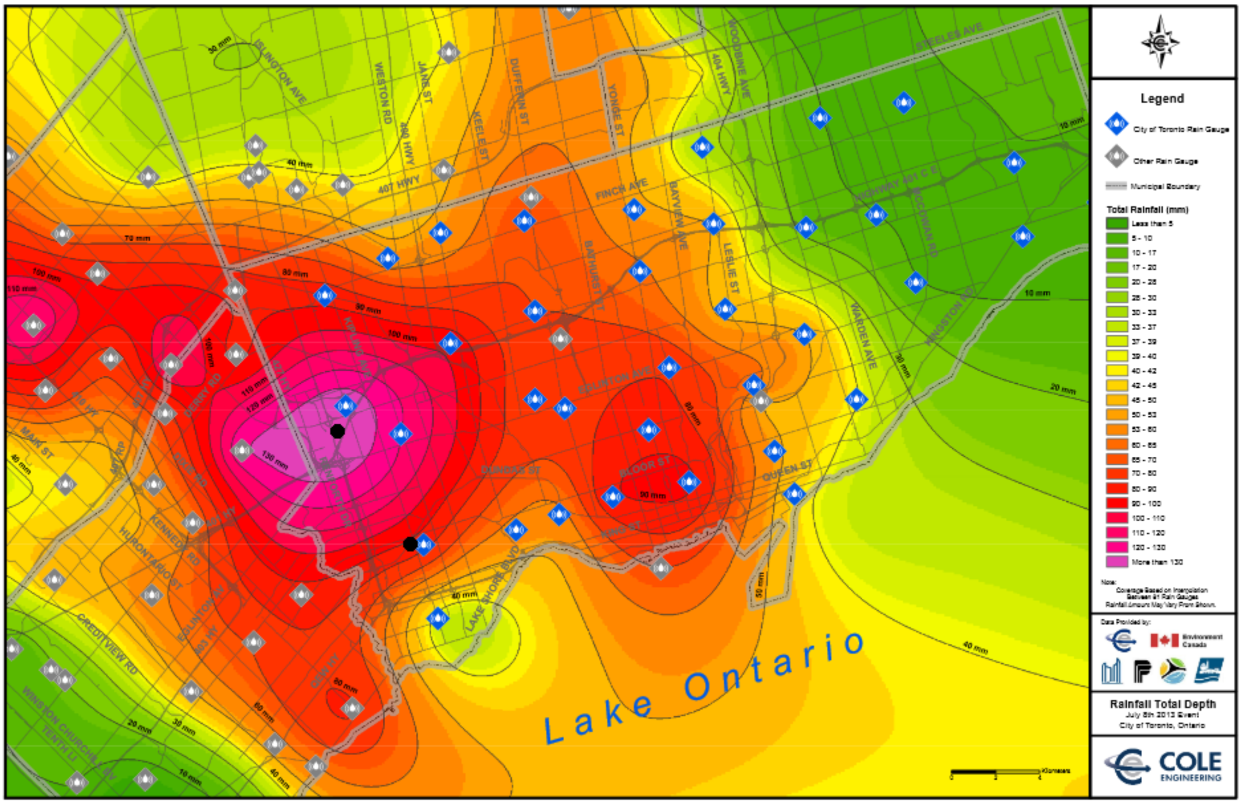


Figure C.11: Contoured 24 hour rainfall totals for the City of Toronto with the locations of Richview and Manby TS superimposed (black dots) added. High resolution PDF map of rainfall totals is available online: http://coleengineering.ca/wordpress/wp-content/themes/Evolution/pdf/2013-articles/rainfall-map.pdf (Cole Engineering Group, 2013)

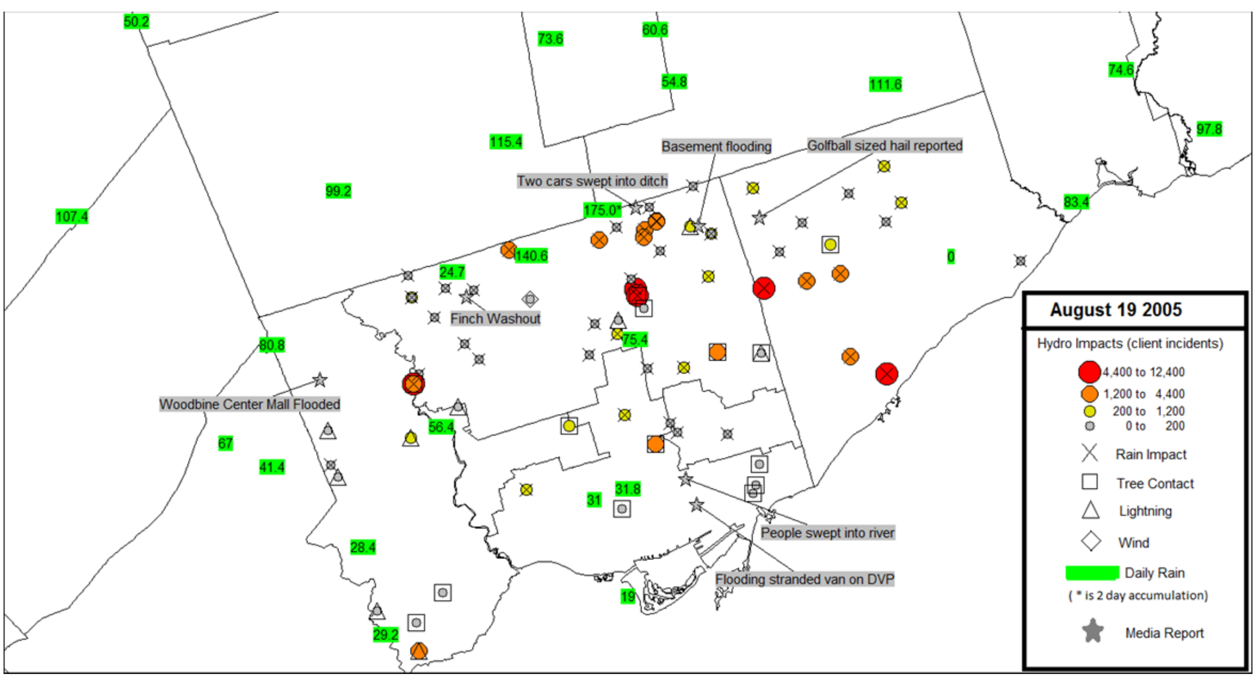


Figure C.12: August 19, 2005 severe thunderstorm event. Map of impacts combining impact types from ITIS and media reports with meteorological data.

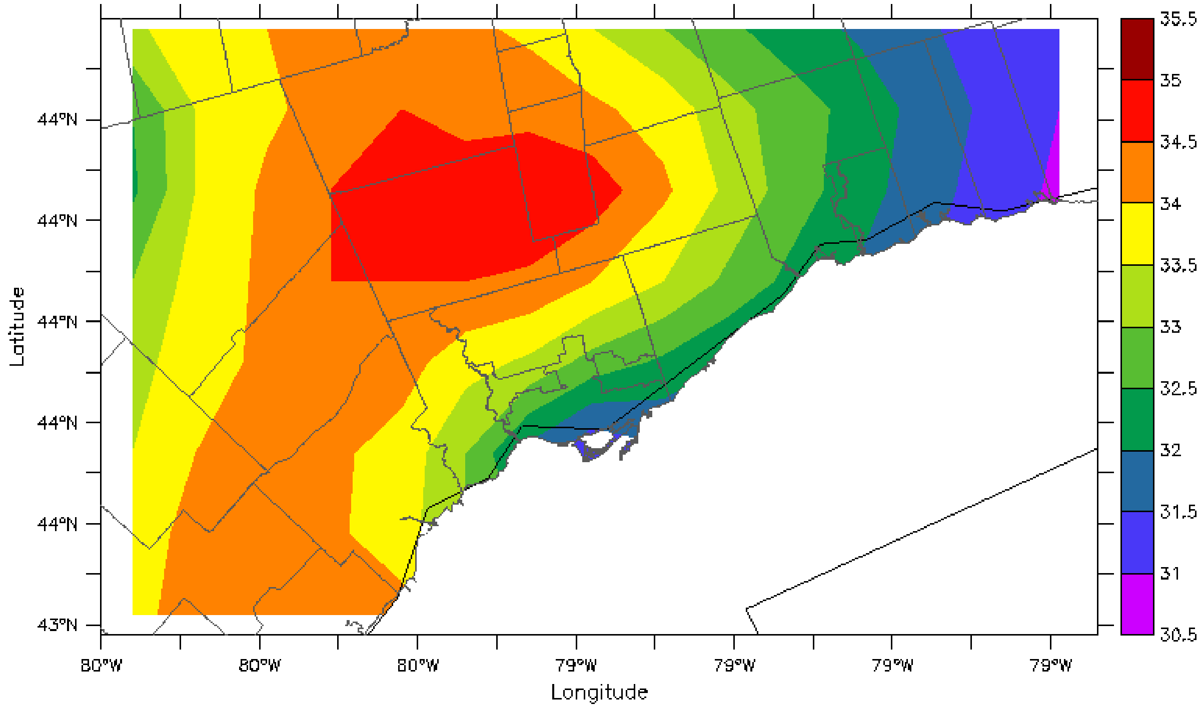


Figure C.13: July 16, 2006, maximum surface temperature (°C) for Toronto and surrounding areas. Data from Cangrd gridded data set.

Appendix D
Risk Assessment Matrix

Study Period	Evaluation	Other Comment	1	High Temperature					2	High Temperature					3	High Temperature				
	Load Projections/ Capacity / Redundancy		Maximum temp above 25 °C						Maximum temp above 30 °C						Maximum temp above 35 °C					
Infrastructure Class or Category			Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
1 Transmission Step-down to Municipal																				
1.1 Former Toronto																				
1.1.1 Downtown core stations	Station capacity by 2050 : Low	Stations are indoors	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.1.2 Downtown outer stations w/o a station	Station capacity by 2050 : Low	Stations are indoors	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.1.3 Station (13.8 kV)	Station capacity by 2050 : Low	Outdoor station	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.2 Horseshoe Area																				
1.2.1 Station	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.2.2 Station	Station capacity by 2050 : Good	Stations are outdoor stations	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Power transformer : Overload	3	3	21
1.2.3 East stations	Station capacity by 2050 : Good	Stations are outdoor stations	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Power transformer : Overload	3	3	21
1.2.4 Station	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.2.5 Station (27.6 kV)	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.2.6 Station	Station capacity by 2050 : Good	Stations are outdoor stations	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Power transformer : Overload	3	3	21
1.2.7 Northwest stations	Station capacity by 2050 : Good	Stations are outdoor stations	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Power transformer : Overload	3	3	21
1.2.8 2 Stations	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.2.9 Southwest stations	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
2 Municipal Stations (divided by geography)																				
2.1 Toronto Hydro to Toronto Hydro & Private owner Ship																				
2.1.1 Former Toronto (indoor/outdoor)	Low	Most stations are located indoors in buildings	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
2.1.2 Horseshoe Area (indoor/outdoor)	Good	Most stations are located outdoors	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Power transformer : Overload	3	3	21
2.1.3 Toronto Hydro to Private owner ship	n/a - no transfer possible	Stations are indoors	N	7			2	-1	N	7				-1	Y	7	Power transformer : Overload	3+	4	28
3 Feeder Configuration : Underground (divided by																				
3.1 Horseshoe Area: Dual Radial System (underground) &																				
3.1.1 Submersible type	moderate / usually serves multiple customers		N	7				-1	N	7	Ability to access service (see human resources)			-1	Y	7	High demand: Stressed cables and transformers	2	2	14
3.1.2 Vault type:																				
- Above ground	moderate / usually serves 1 customer		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2	2	14
- Below ground	moderate / usually serves 1 customer		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2	2	14
3.1.3 Padmount station	moderate / usually serves multiple customers		N	7				-1	N	7	idem			-1	Y	7	Pad mount transformers overheating, cables stressed	2	2	14
3.2 Former Toronto : Dual Radial System (underground) &																				
3.2.1 Submersible type	low/ usually serves multiple customers		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2+	3	21
3.2.2 Vault type:																				
- Above ground	low / usually serves 1 customer		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2+	3	21
- Below ground	low / usually serves 1 customer		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2+	3	21
3.2.3 Padmount station	low / usually serves multiple customers		N	7				-1	N	7	idem			-1	Y	7	Pad mount transformers overheating, cables stressed	2+	3	21
3.3 Compact Loop Design (underground)																				
3.3.1 Former Toronto: Subway type	Moderate to good		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2	2	14
3.4 13.8 kV Network																				
3.4.1 Former Toronto	Best		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2	2	14
3 Feeder Configuration : Overhead (divided by																				
3.5 Overhead																				
Radial																				
3.5.1 4.16 kV	Low / less affected		N	7				-1	N	7				-1	Y	7	Onan power transformers, conductors	2+	3	21
3.5.2 13.8 kV	Low / more affected		N	7				-1	N	7				-1	Y	7	Onan power transformers, conductors	2+	3	21
3.5.3 27.6 kV	Low / more affected		N	7				-1	N	7				-1	Y	7	Onan power transformers, conductors	2+	3	21
Loop																				
3.5.4 4.16 kV	Good / less affected		N	7				-1	N	7				-1	Y	7	Onan power transformers, conductors	2	2	14
3.5.5 13.8 kV	Good / more affected		N	7				-1	N	7				-1	Y	7	Onan power transformers, conductors	2	2	14
3.5.6 27.6 kV	Good / more affected		N	7				-1	N	7				-1	Y	7	Onan power transformers, conductors	2	2	14
4 Communications (divided by types)																				
4.1 Protection and control systems			Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14
4.2 SCADA + Wireless network	N/A		N	7				-1	N	7				-1	N	7				-1
5 Civil Structures (divided by categories)																				
5.1 Transmission & Municipal Stations																				
Outdoor																				
5.1.1 Equipment support			N	7				-1	N	7				-1	N	7				-1
5.1.2 Gantry			N	7				-1	N	7				-1	N	7				-1
5.2 Underground feeders : Former Toronto																				
5.2.1 Reinforced concrete cable chambers	Low		N	7				-1	N	7				-1	N	7				-1
5.2.2 Concrete vaults (reinforced)	Low		N	7				-1	N	7				-1	N	7				-1
5.2.3 Underground cable ducts	Low		N	7				-1	N	7				-1	N	7				-1
5.3 Underground feeders : Horseshoe Area																				
5.3.1 Reinforced concrete cable chambers	moderate		N	7				-1	N	7				-1	N	7				-1
5.3.2 Concrete vaults (reinforced)	moderate		N	7				-1	N	7				-1	N	7				-1
5.3.3 Underground cable ducts	moderate		N	7				-1	N	7				-1	N	7				-1
6 Human Resources																				
6.1 Emergency Response			N	7				-1	Y	7		2-3	3	21	Y	7		4	4	28

Study Period	4	High Temperature					5	Average temperature >30°C					6	Heat Wave				
	Maximum temp above 40 °C						Average temp. Over 30°C on a 24h basis						3 days with max temp. above 30 °C					
Infrastructure Class or Category	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
1 Transmission Step-down to Municipal																		
1.1 Former Toronto																		
1.1.1 Downtown core stations	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.1.2 Downtown outer stations w/o a station	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.1.3 Station (13.8 kV)	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.2 Horseshoe Area																		
1.2.1 Station	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.2.2 Station	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	4	4	28
1.2.3 East stations	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	4	4	28
1.2.4 Station	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.2.5 Station (27.6 kV)	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.2.6 Station	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	4	4	28
1.2.7 Northwest stations	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	4	4	28
1.2.8 2 Stations	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.2.9 Southwest stations	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
2 Municipal Stations (divided by geography)																		
2.1 Toronto Hydro to Toronto Hydro & Private owner Ship																		
2.1.1 Former Toronto (indoor/outdoor)	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
2.1.2 Horseshoe Area (indoor/outdoor)	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	4	4	28
2.1.3 Toronto Hydro to Private owner ship	Y	7	Power transformer : Overload	5+	6	42	Y	7	Power transformer: Overload	5+	6	42	Y	7	Power transformer: Overload	3+	4	28
3 Feeder Configuration : Underground (divided by																		
3.1 Horseshoe Area: Dual Radial System (underground) &																		
3.1.1 Submersible type	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21
3.1.2 Vault type:																		
- Above ground	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21
- Below ground	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21
3.1.3 Padmount station	Y	7	Pad mount transformers overheating	3	3	21	Y	7	Pad mount transformers overheating	3	3	21	Y	7	Pad mount transformers overheating	3	3	21
3.2 Former Toronto : Dual Radial System (underground) &																		
3.2.1 Submersible type	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	7	High demand: Stressed cables and transformers	2+	3	21	Y	7	High demand: Stressed cables and transformers	3+	4	28
3.2.2 Vault type:																		
- Above ground	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	7	High demand: Stressed cables and transformers	2+	3	21	Y	7	High demand: Stressed cables and transformers	3+	4	28
- Below ground	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	7	High demand: Stressed cables and transformers	2+	3	21	Y	7	High demand: Stressed cables and transformers	3+	4	28
3.2.3 Padmount station	Y	7	Pad mount transformers overheating, cables stressed	3+	4	28	Y	7	Pad mount transformers overheating, cables stressed	3+	4	28	Y	7	Pad mount transformers overheating, cables stressed	3+	4	28
3.3 Compact Loop Design (underground)																		
3.3.1 Former Toronto: Subway type	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21
3.4 13.8 kV Network																		
3.4.1 Former Toronto	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21
3 Feeder Configuration : Overhead (divided by																		
3.5 Overhead																		
Radial																		
3.5.1 4.16 kV	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	3+	4	28
3.5.2 13.8 kV	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	3+	4	28
3.5.3 27.6 kV	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	3+	4	28
Loop																		
3.5.4 4.16 kV	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	3	3	21
3.5.5 13.8 kV	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	3	3	21
3.5.6 27.6 kV	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	3	3	21
4 Communications (divided by types)																		
4.1 Protection and control systems	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14
4.2 SCADA + Wireless network	Y	7	Interrupters: Unusual conditions with temp over 40°C	1	1	7	N	7				-1	N	7				-1
5 Civil Structures (divided by categories)																		
5.1 Transmission & Municipal Stations																		
Outdoor																		
5.1.1 Equipment support	N	7				-1	N	7				-1	N	7				-1
5.1.2 Gantry	N	7				-1	N	7				-1	N	7				-1
5.2 Underground feeders : Former Toronto																		
5.2.1 Reinforced concrete cable chambers	N	7				-1	N	7				-1	N	7				-1
5.2.2 Concrete vaults (reinforced)	N	7				-1	N	7				-1	N	7				-1
5.2.3 Underground cable ducts	N	7				-1	N	7				-1	N	7				-1
5.3 Underground feeders : Horseshoe Area																		
5.3.1 Reinforced concrete cable chambers	N	7				-1	N	7				-1	N	7				-1
5.3.2 Concrete vaults (reinforced)	N	7				-1	N	7				-1	N	7				-1
5.3.3 Underground cable ducts	N	7				-1	N	7				-1	N	7				-1
6 Human Resources																		
6.1 Emergency Response	Y	7	health issue	5	5	35	Y	7	health issue	4	4	28	Y	7	health issue	4	4	28

Study Period	7	High Nighttime Temperatures					8	Extreme Rainfall					9	Freezing Rain/Ice Storm				
	Min temp ≥ 23°C						100 mm <1 day + antecedent						15 mm (tree branches)					
Infrastructure Class or Category	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
1 Transmission Step-down to Municipal																		
1.1 Former Toronto																		
1.1.1 Downtown core stations	Y	7	Power transformer: Overload - Load shedding	3+	4	28	Y	2	Probability of flood is low due to sump pumps in stations, 5 stations have batteries/switchgear in basement, but batteries will be moved by 2030s. Some stations will still have switchgear in basement	1+	2	4	N	7				-1
1.1.2 Downtown outer stations w/o a station	Y	7	Power transformer: Overload - Load shedding	3+	4	28	Y	2		1+	2	4	N	7				-1
1.1.3 Station (13.8 kV)	Y	7	Power transformer: Overload - Load shedding	3+	4	28	Y	2		1+	2	4	Y	7	Access to station equipment	1	1	7
1.2 Horseshoe Area																		
1.2.1 Station	Y	7	Power transformer: Overload - Load shedding	3+	4	28	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.2 Station	Y	7	Power transformer: Overload - Load shedding	3	3	21	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.3 East stations	Y	7	Power transformer: Overload - Load shedding	3	3	21	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.4 Station	Y	7	Power transformer: Overload - Load shedding	3+	4	28	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.5 Station (27.6 kV)	Y	7	Power transformer: Overload - Load shedding	3+	4	28	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.6 Station	Y	7	Power transformer: Overload - Load shedding	3	3	21	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.7 Northwest stations	Y	7	Power transformer: Overload - Load shedding	3	3	21	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.8 2 Stations	Y	7	Power transformer: Overload - Load shedding	3+	4	28	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.9 Southwest stations	Y	7	Power transformer: Overload - Load shedding	3+	4	28	N	6				-1	Y	7	Access to station equipment	1	1	7
2 Municipal Stations (divided by geography)																		
2.1 Toronto Hydro to Toronto Hydro & Private owner Ship																		
2.1.1 Former Toronto (indoor/outdoor)	Y	7	Power transformer: Overload - Load shedding	3+	4	28	N	6	No batteries in basement by 2030s	6	6	-1	N	7				-1
2.1.2 Horseshoe Area (indoor/outdoor)	Y	7	Power transformer: Overload - Load shedding	3	3	21	N	6	No batteries in basement by 2030s	6	6	-1	Y	7	Access to station equipment	0	0	0
2.1.3 Toronto Hydro to Private owner ship	Y	7	Power transformer: Overload	3+	4	28	N	6				-1	N	7				-1
3 Feeder Configuration : Underground (divided by																		
3.1 Horseshoe Area: Dual Radial System (underground) &																		
3.1.1 Submersible type	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	6	Water treeing, flooding, reduced dielectric strength	3	3	18	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3.1.2 Vault type:																		
- Above ground	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	6	Access	1	1	6	N	7				-1
- Below ground	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	6	All electrical components (not submersible), + 2 if pumps fails	5	5	30	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3.1.3 Padmount station	Y	7	Pad mount transformers overheating	3	3	21	Y	6	Access	1	1	6	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3.2 Former Toronto : Dual Radial System (underground) &																		
3.2.1 Submersible type	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	6	Water treeing, flooding, reduced dielectric strength	3+	4	24	Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14
3.2.2 Vault type:																		
- Above ground	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	6	Access	1+	2	12	N	7				-1
- Below ground	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	6	All electrical components (not submersible), + 2 if pumps fails	5+	6	36	Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14
3.2.3 Padmount station	Y	7	Pad mount transformers overheating, cables stressed	3+	4	28	Y	6	Access	1+	2	12	Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14
3.3 Compact Loop Design (underground)																		
3.3.1 Former Toronto: Subway type	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	6	Water treeing, flooding, reduced dielectric strength	3	3	18	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3.4 13.8 kV Network																		
3.4.1 Former Toronto	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	6	Old N/W protectors are not submersible	5	5	30	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3 Feeder Configuration : Overhead (divided by																		
3.5 Overhead																		
Radial																		
3.5.1 4.16 kV	Y	7	Onan power transformers	1+	2	14	N	6	Note: severity score for light rainfall. Mist + humidity = Visibility.	1+	2	-1	Y	7	Conductors (tree contacts)	5+	6	42
3.5.2 13.8 kV	Y	7	Onan power transformers	1+	2	14	N	6	Severity score for light rainfall. Mist + humidity = Visibility. Light rainfall + dirt = flash over	3+	4	-1	Y	7	Conductors (tree contacts)	5+	6	42
3.5.3 27.6 kV	Y	7	Onan power transformers	1+	2	14	N	6	idem.	3+	4	-1	Y	7	Conductors (tree contacts)	5+	6	42
Loop																		
3.5.4 4.16 kV	Y	7	Onan power transformers	1	1	7	N	6	Note: severity score for light rainfall. Mist + humidity = Visibility.	1	1	-1	Y	7	Conductors (tree contacts)	5	5	35
3.5.5 13.8 kV	Y	7	Onan power transformers	1	1	7	N	6	Severity score for light rainfall. Mist + humidity = Visibility. Light rainfall + dirt = flash over	3	3	-1	Y	7	Conductors (tree contacts)	5	5	35
3.5.6 27.6 kV	Y	7	Onan power transformers	1	1	7	N	6	idem	3	3	-1	Y	7	Conductors (tree contacts)	5	5	35
4 Communications (divided by types)																		
4.1 Protection and control systems	Y	7	Batteries: lifespan	2	2	14	N	6	Batteries will be moved to ground floor by 2030s	6	6	-1	N	7				-1
4.2 SCADA + Wireless network	N	7				-1	N	6				-1	N	7				-1
5 Civil Structures (divided by categories)																		
5.1 Transmission & Municipal Stations																		
Outdoor																		
5.1.1 Equipment support	N	7				-1	Y	6	Corrosion	0	0	0	N	7				-1
5.1.2 Gantry	N	7				-1	Y	6	Corrosion	0	0	0	N	7				-1
5.2 Underground feeders : Former Toronto																		
5.2.1 Reinforced concrete cable chambers	N	7				-1	Y	6	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	12	Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14
5.2.2 Concrete vaults (reinforced)	N	7				-1	Y	6	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	12	Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14
5.2.3 Underground cable ducts	N	7				-1	N	6				-1	N	7				-1
5.3 Underground feeders : Horseshoe Area																		
5.3.1 Reinforced concrete cable chambers	N	7				-1	Y	6	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	6	Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7
5.3.2 Concrete vaults (reinforced)	N	7				-1	Y	6	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	6	Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7
5.3.3 Underground cable ducts	N	7				-1	N	6				-1	N	7				-1
6 Human Resources																		
6.1 Emergency Response	Y	7		0	0	0	Y	6	access to site, delays, rain to stop	2-3	3	18	Y	7	safe access to site	4	4	28

10	Freezing Rain/Ice Storm					11	Freezing Rain/Ice Storm					12	High Winds					13	High Winds				
	25 mm (design threshold)						60 mm(major outages)						70 km/h+ (tree branches)						90 km/h (min design value; TH higher??)				
Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
N	7				-1	N	4				-1	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Exit lines	6	6	42	Y	4	Exit lines: overhead	7	7	28	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				-1	N	7				-1
N	7				-1	N	4				-1		7				0	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4		7				0	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				-1	N	7				-1
Y	7	Poles & conductors downed, Salt+Contamination	6+	7	49	Y	4	Poles & conductors downed, Salt+Contamination	6+	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49
Y	7	Poles & conductors downed, Salt+Contamination	6	6	42	Y	4	Poles & conductors downed, Salt+Contamination	6	6	24	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Access	1	1	7	Y	4	Access	1	1	4	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	1	1	7	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	8	N	7				-1	N	7				-1
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	8	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	4	N	7				-1	N	7				-1
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	4	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	safe access to site	6	6	42	Y	4	safe access to site	6	6	24	Y	7	access, location has to be declare safe	2	2	14	Y	7	access, location has to be declare safe	2	2	14

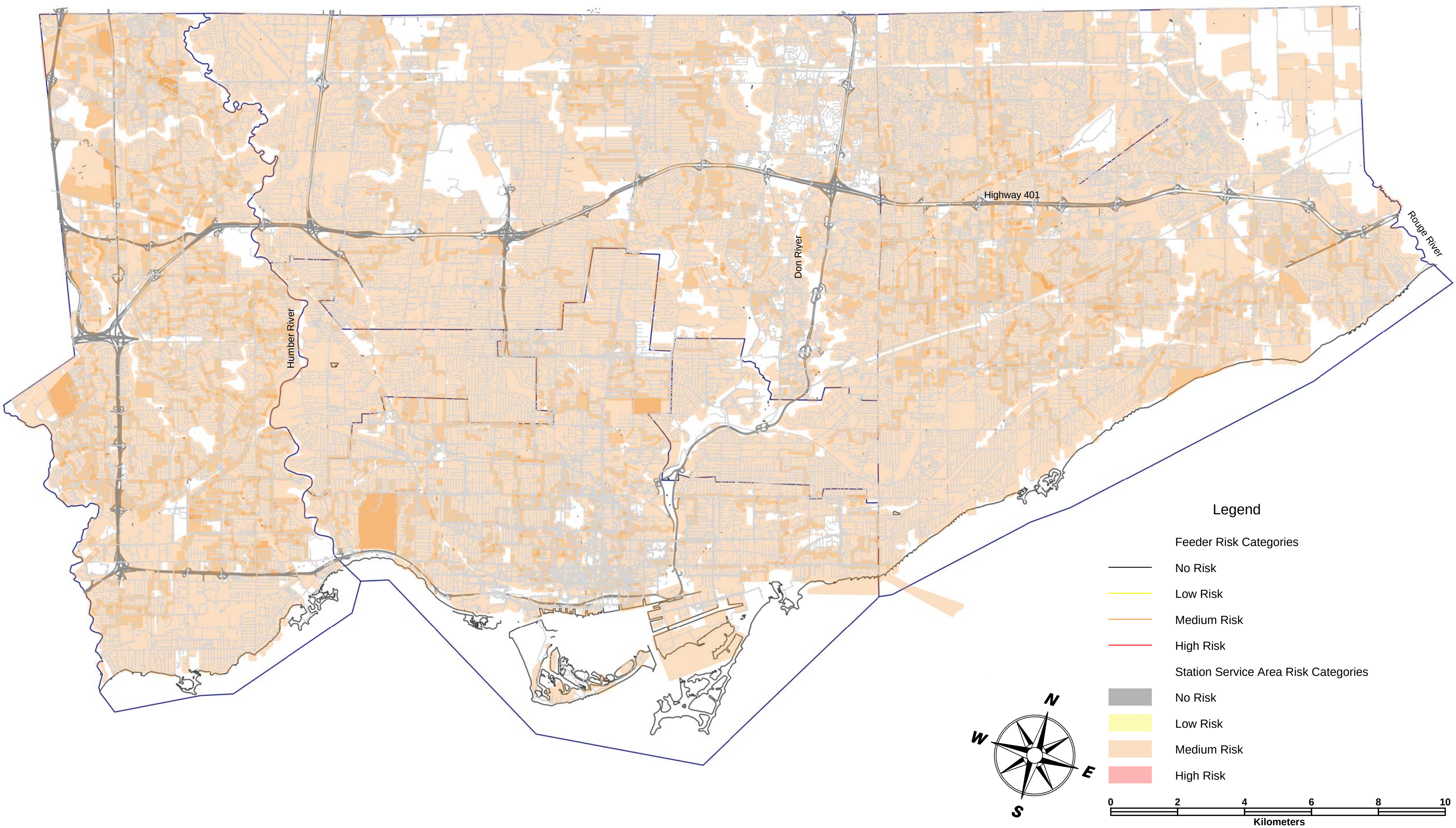
14	High Winds					15	Tornadoes					16	Tornadoes				
	120 km/h						EF1+						EF2+ (concrete poles, permanent structures)				
Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
N	7				-1	Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0
N	7				-1	Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	Building and equipment can be damaged	7	7	0
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0
N	7				-1	Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0
Y	7	Exit lines, and flying debris could impact the equipement	6	6	42	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0
N	7				-1	N	1				-1	N	0				-1
N	7				-1	N	1				-1	N	0				-1
N	7				-1	N	1				-1	N	0				-1
N	7				-1	N	1				-1	N	0				-1
Y	7	Debris could impact the equipement	1	1	7	Y	1	Pad mount equipment can be damaged	2	2	2	Y	0	Pad mount equipment can be damaged	2	2	0
N	7				-1	N	1				-1	N	0				-1
N	7				-1	N	1				-1	N	0				-1
N	7				-1	N	1				-1	N	0				-1
Y	7	Debris could impact the equipement	1+	2	14	Y	1	Pad mount equipment can be damaged	2+	3	3	Y	0	Pad mount equipment can be damaged	2+	3	0
N	7				-1	N	1				-1	N	0				-1
N	7				-1	N	1				-1	N	0				-1
Y																	
Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0
Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0
Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0
Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0
Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0
Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0
N	7				-1	N	1				-1	N	0				-1
N	7				-1	N	1				-1	N	0				-1
Y	7	TC & CVT structures			0	Y	1	All supports	7	7	7	Y	0	All supports	7	7	0
N	7				-1	Y	1	Gantry	7	7	7	Y	0	Gantry	7	7	0
N	7				-1	N	1				-1	N	0				-1
N	7				-1	N	1				-1	N	0				-1
N	7				-1	N	1				-1	N	0				-1
N	7				-1	N	1				-1	N	0				-1
N	7				-1	N	1				-1	N	0				-1
N	7				-1	N	1				-1	N	0				-1
Y	7	access, location has to be declare safe	2	2	14	Y	1	access, location has to be declare safe	2	2	2	Y	0	access, location has to be declare safe	2	2	0

17	Lightning					18	Snow					19	Snow					20	Frost (ground)				
							Days with > 5 cm						Days with > 10 cm						Extreme cold weather				
Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
N	6				-1	N	7				-1	N	7				-1	N	7				-1
N	6				-1	N	7				-1	N	7				-1	N	7				-1
Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
N	6				-1	N	7				-1	N	7				-1	N	7				-1
Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
N	6				-1	N	7				-1	N	7				-1	N	7				-1
N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
N	6				-1	N	7				-1	N	7				-1	N	7				-1
N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7				-1
											0						0						
N	6				-1	N	7				-1	N	7				-1	N	7				-1
N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7				-1
N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7				-1
N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
Y	6	If arresters don't work, a localize outage can occur	4+	5	30	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	6	If arresters don't work, a localize outage can occur	4+	5	30	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	6	If arresters don't work, a localize outage can occur	4+	5	30	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	6	If arresters don't work, a localize outage can occur	4	4	24	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
Y	6	If arresters don't work, a localize outage can occur	4	4	24	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
Y	6	If arresters don't work, a localize outage can occur	4	4	24	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
N	6				-1	N	7				-1	N	7				-1	N	7				-1
Y	6	Equipment could fail if protection won't work	3	3	18	N	7				-1	N	7				-1	N	7				-1
N	6				-1	N	7				-1	N	7				-1	Y	7	Foundations, frost heave	2	2	14
N	6				-1	N	7				-1	N	7				-1	Y	7	Foundations, frost heave	2	2	14
N	6				-1	Y	7	Salt corrosion - concrete and steel	1+	2	14	Y	7	Salt corrosion - concrete and steel, access	1+	2	14	Y	7	Foundations, frost heave	1+	2	14
N	6				-1	Y	7	Salt corrosion - concrete and steel	1+	2	14	Y	7	Salt corrosion - concrete and steel, access	1+	2	14	Y	7	Foundations, frost heave	1+	2	14
N	6				-1	N	7				-1	N	7				-1	Y	7	Foundations, frost heave	1+	2	14
N	6				-1	Y	7	Salt corrosion - concrete and steel	1	1	7	Y	7	Salt corrosion - concrete and steel, access	1	1	7	Y	7	Foundations, frost heave	1	1	7
N	6				-1	Y	7	Salt corrosion - concrete and steel	1	1	7	Y	7	Salt corrosion - concrete and steel, access	1	1	7	Y	7	Foundations, frost heave	1	1	7
N	6				-1	N	7				-1	N	7				-1	Y	7	Foundations, frost heave	1	1	7
Y	6	staff security	3-4	4	24	Y	7	Access, staff security	1-2	2	14	Y	7	Access, staff security	3	3	21	N	7				

Appendix E
Risk Maps

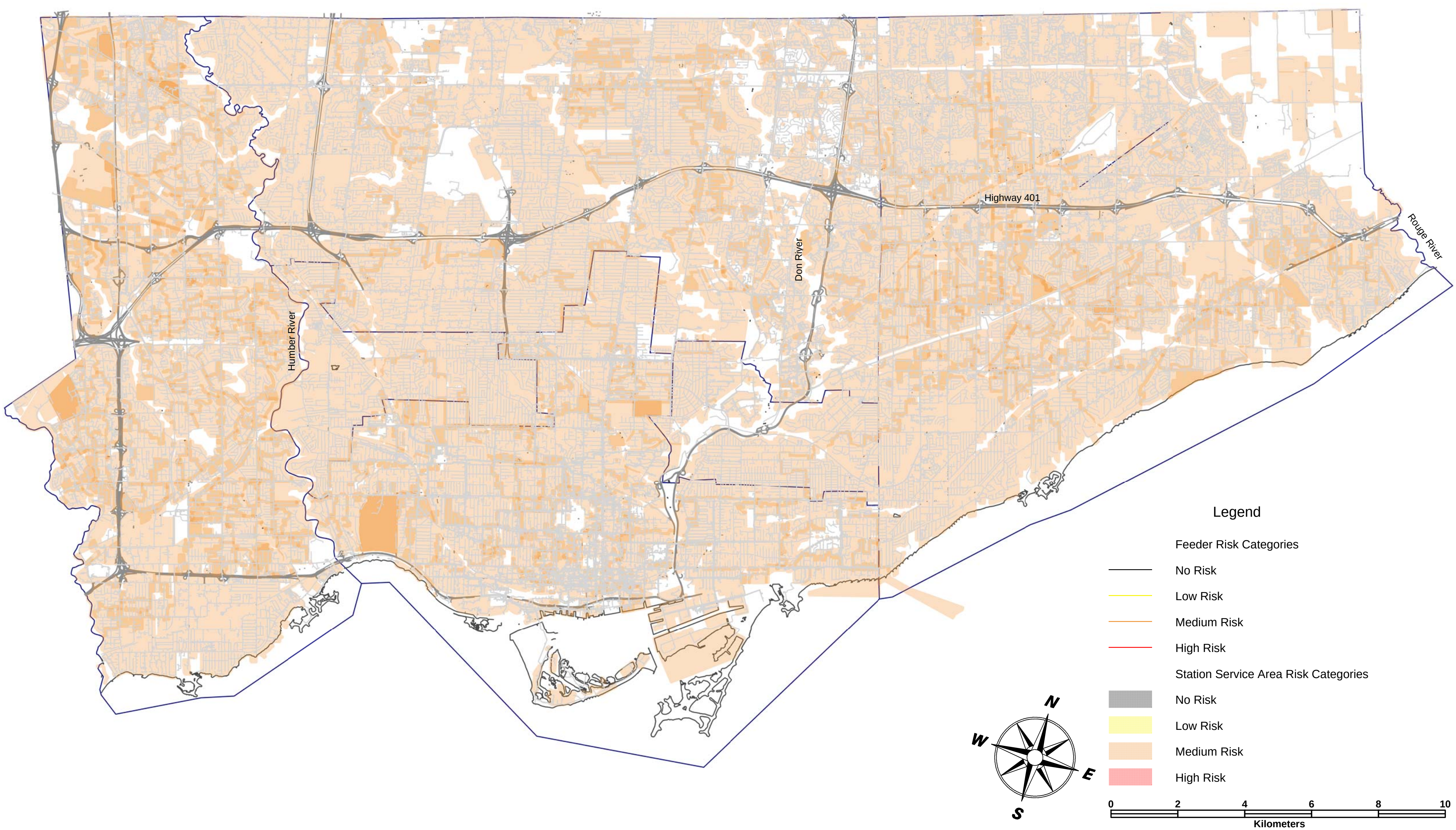
PIEVC Phase 2 Climate Change Risk Map by 2050

1. High Temperature Maximum Above 25 C



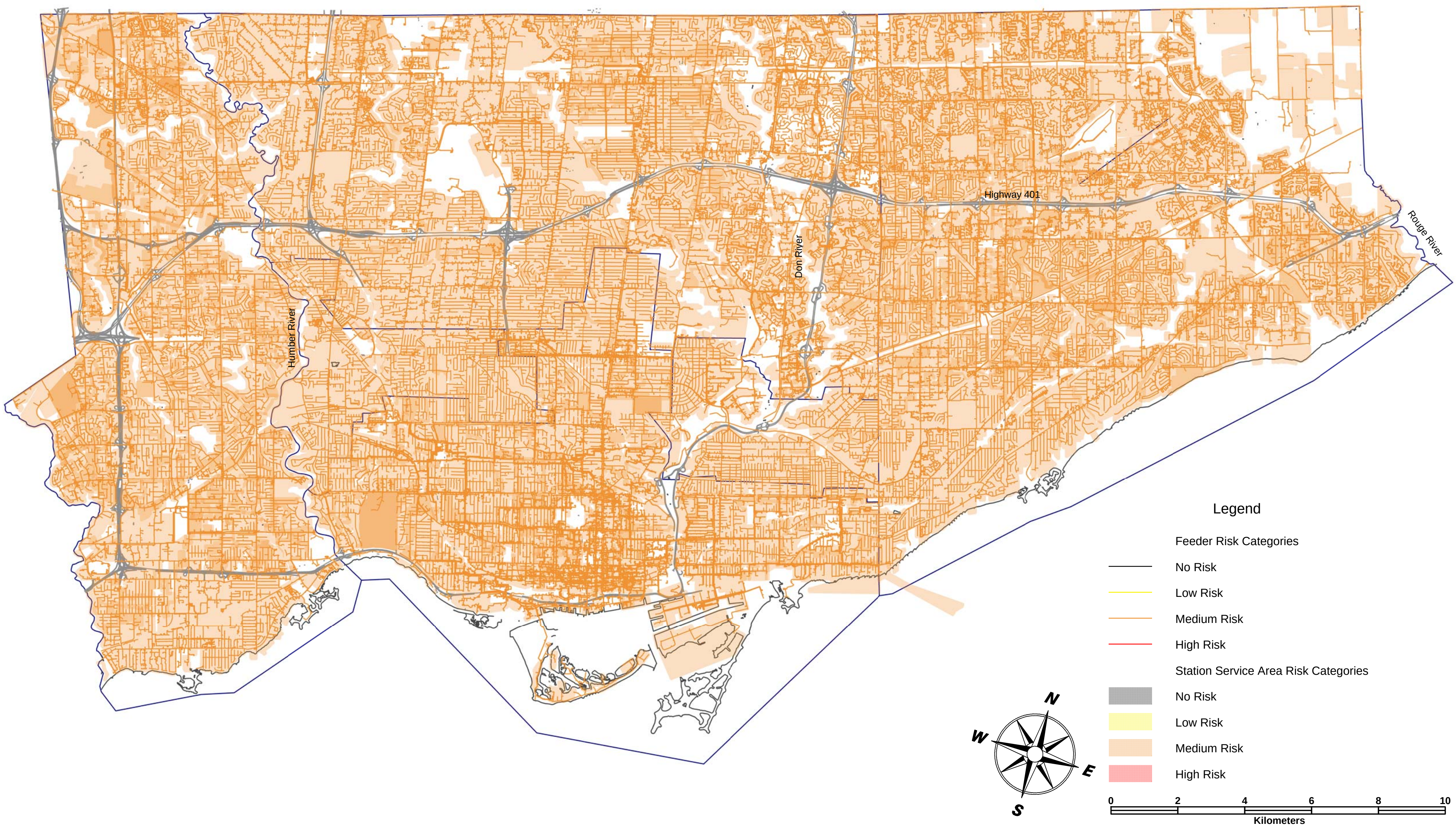
PIEVC Phase 2 Climate Change Risk Map by 2050

2. High Temperature Maximum Above 30 C



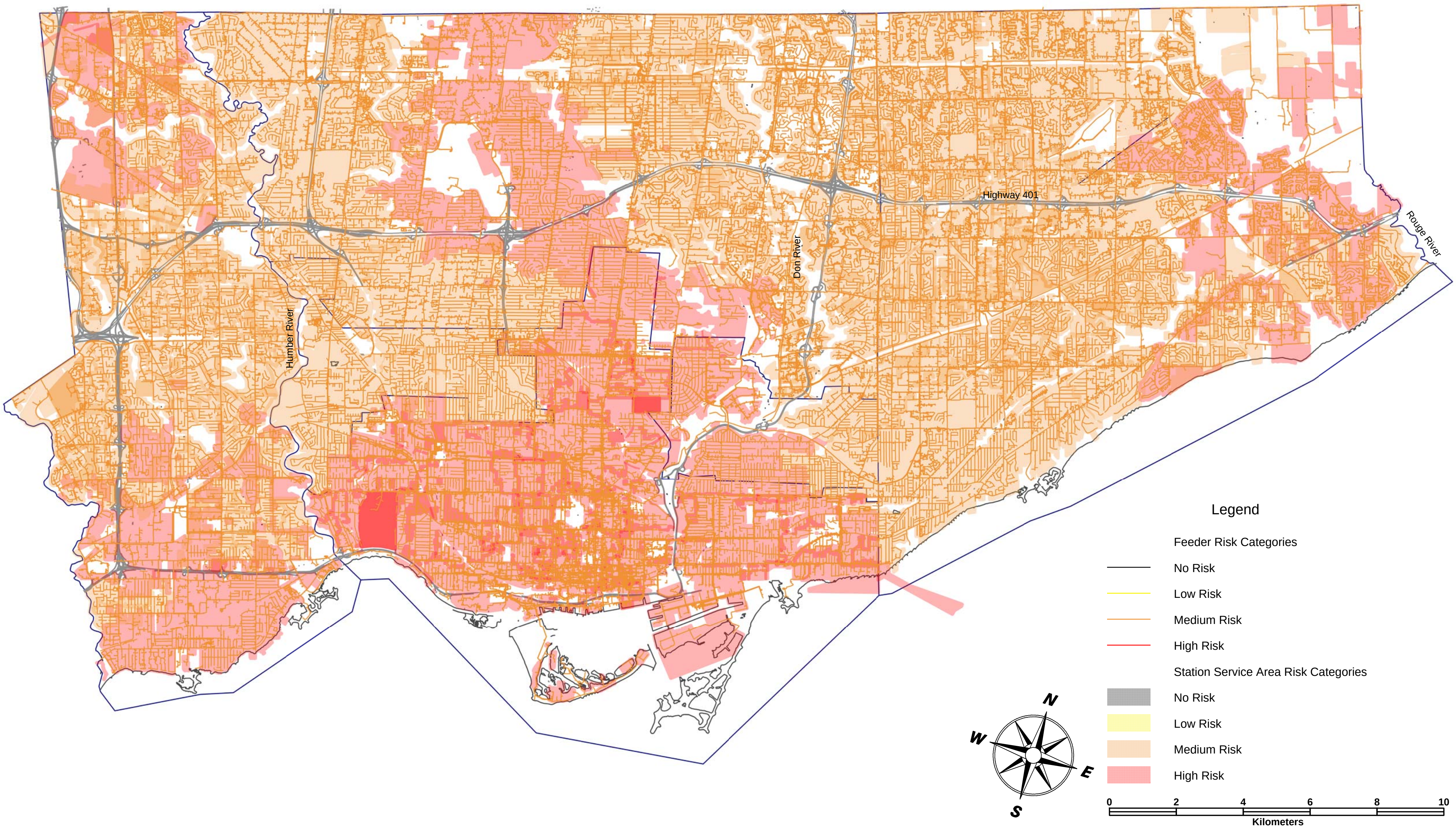
PIEVC Phase 2 Climate Change Risk Map by 2050

3. High Temperature Maximum Above 35 C



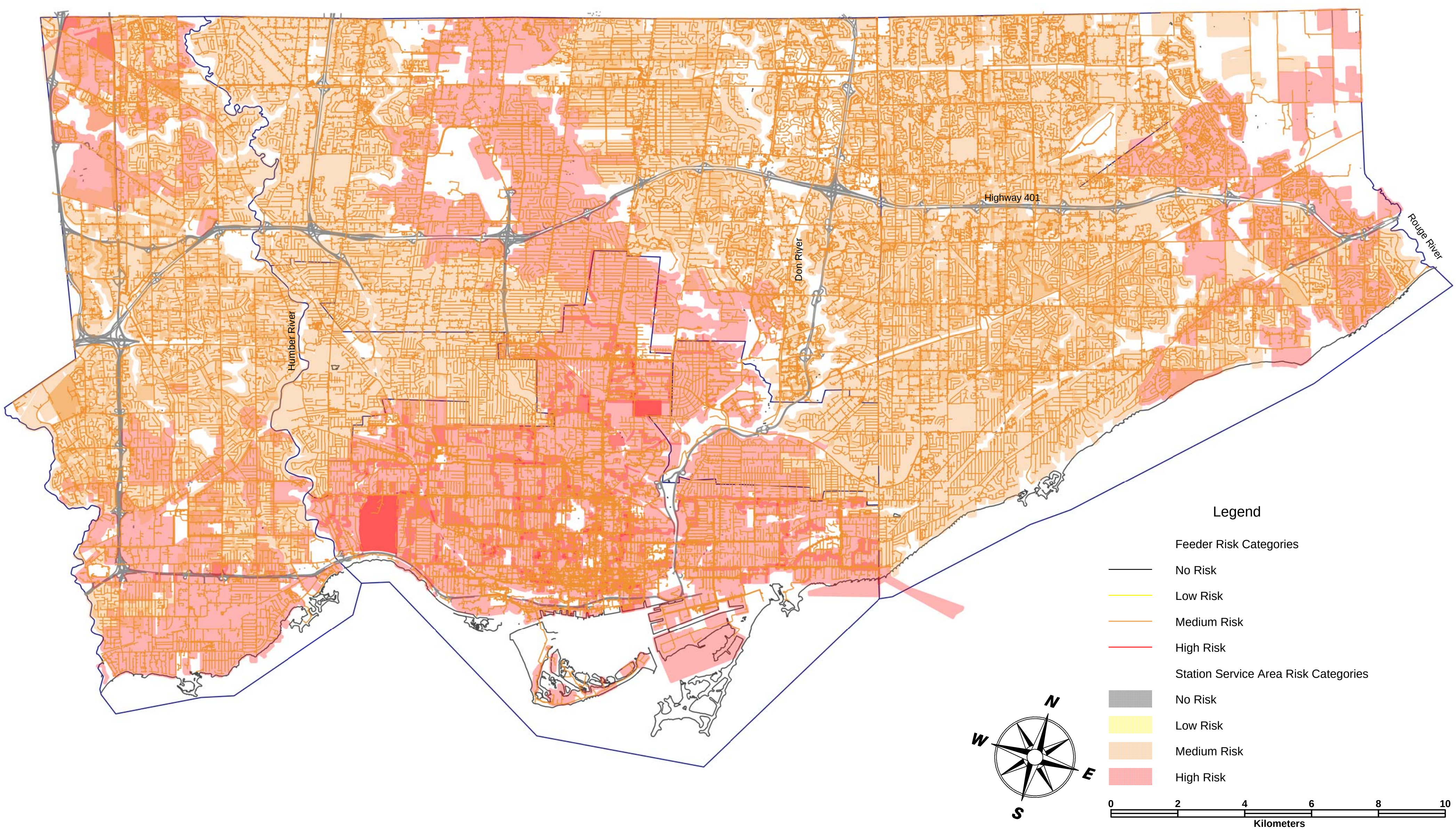
PIEVC Phase 2 Climate Change Risk Map by 2050

4. High Temperature Maximum Above 40 C



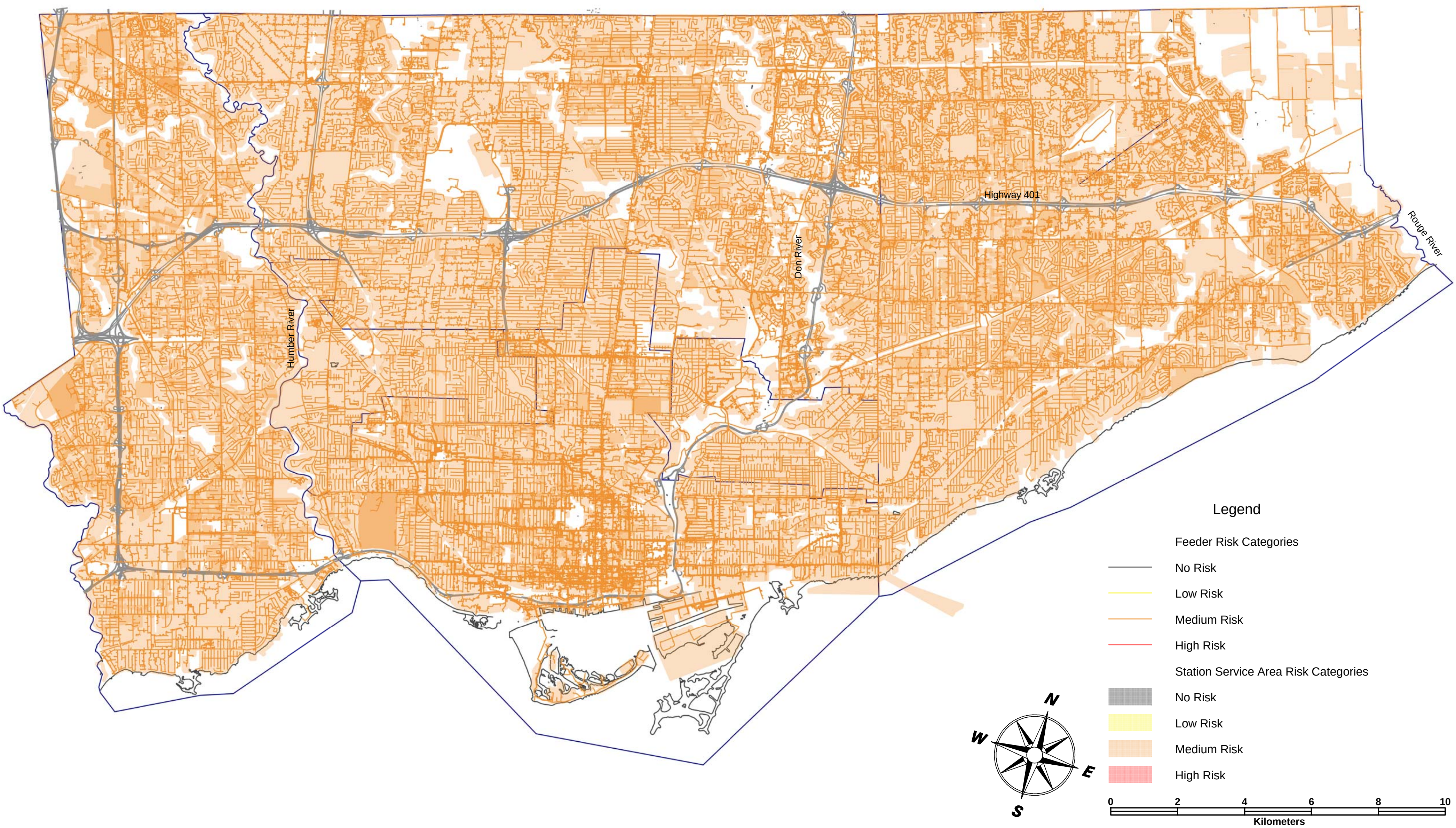
PIEVC Phase 2 Climate Change Risk Map by 2050

5. Average Temperature Above 30 C for 24 Hours



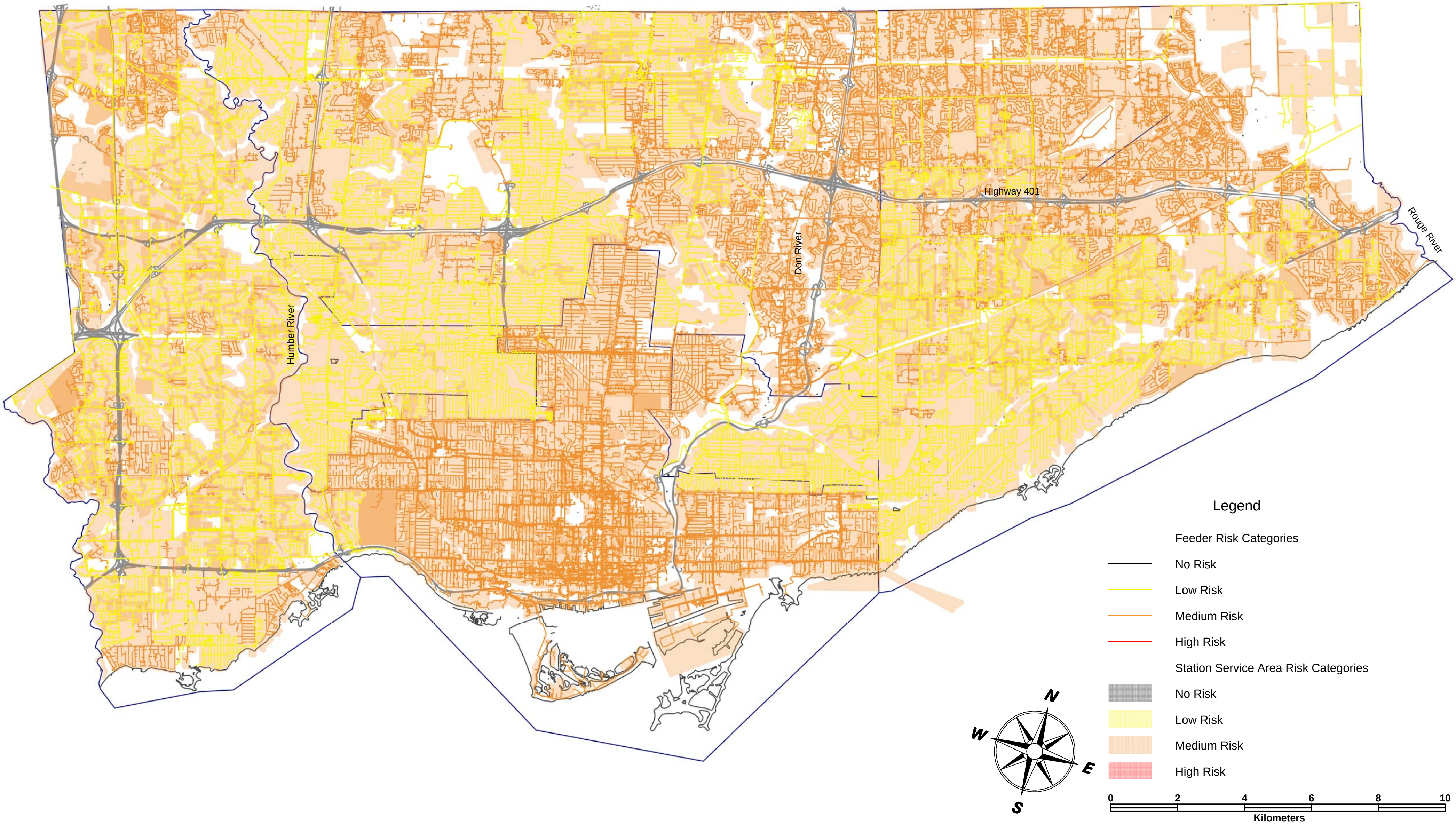
PIEVC Phase 2 Climate Change Risk Map by 2050

6. Heat Wave 3 Day with Maximum Temperature Above 30 C



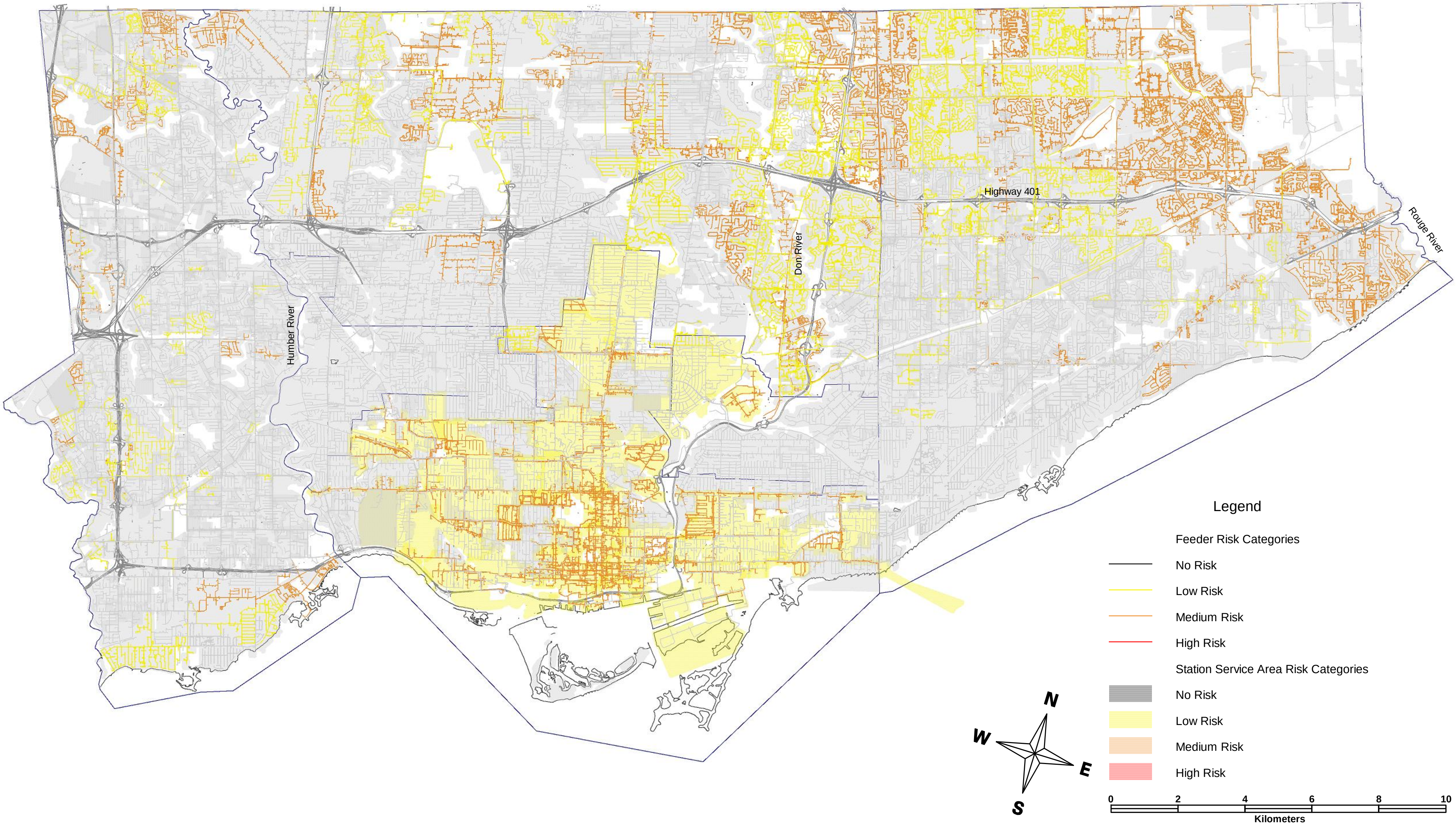
PIEVC Phase 2 Climate Change Risk Map by 2050

7. High Night Time Temperature Minimum Above 23 C



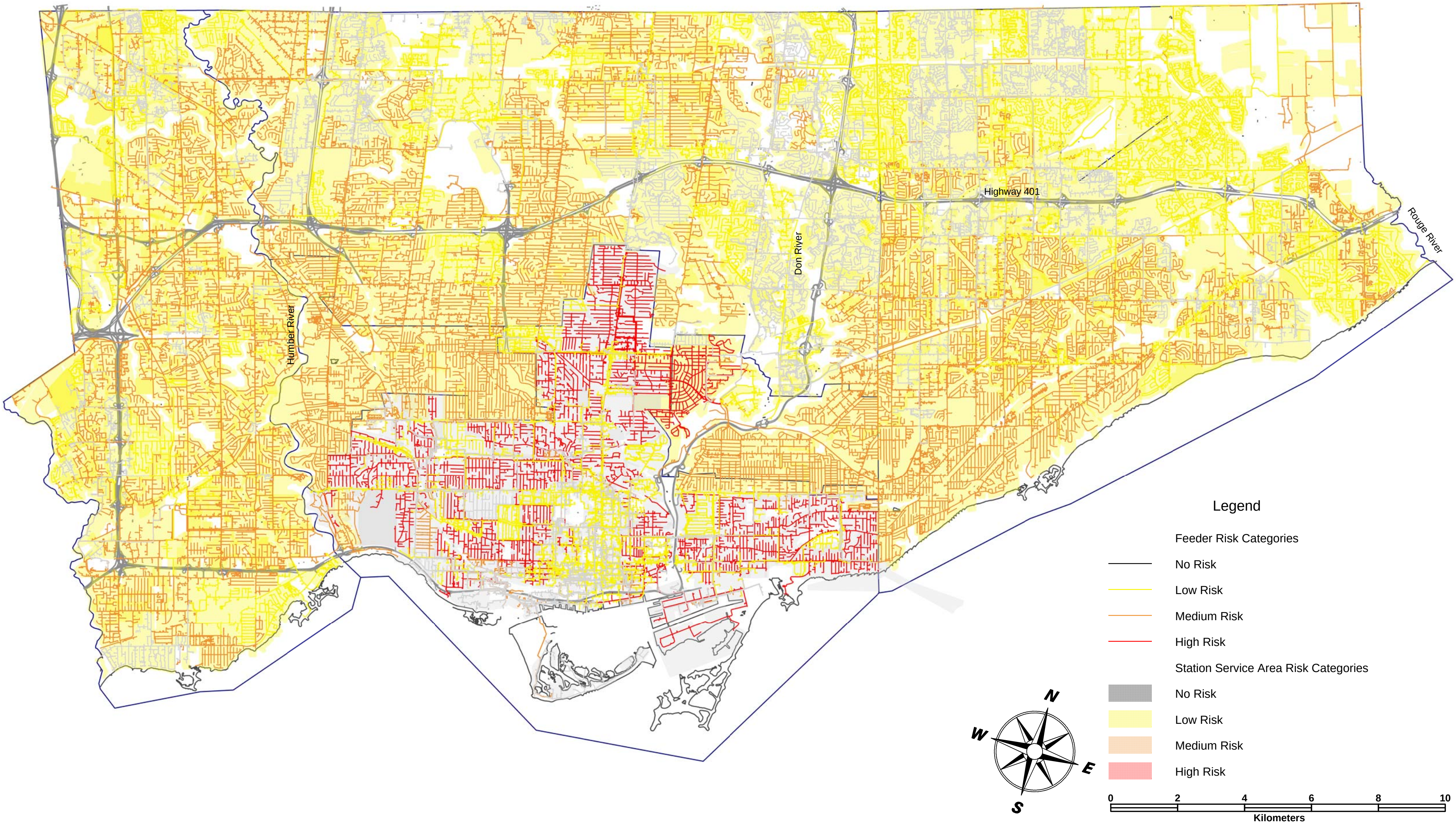
PIEVC Phase 2 Climate Change Risk Map by 2050

8. Extreme Rainfall 100mm in Less than 24 Hours



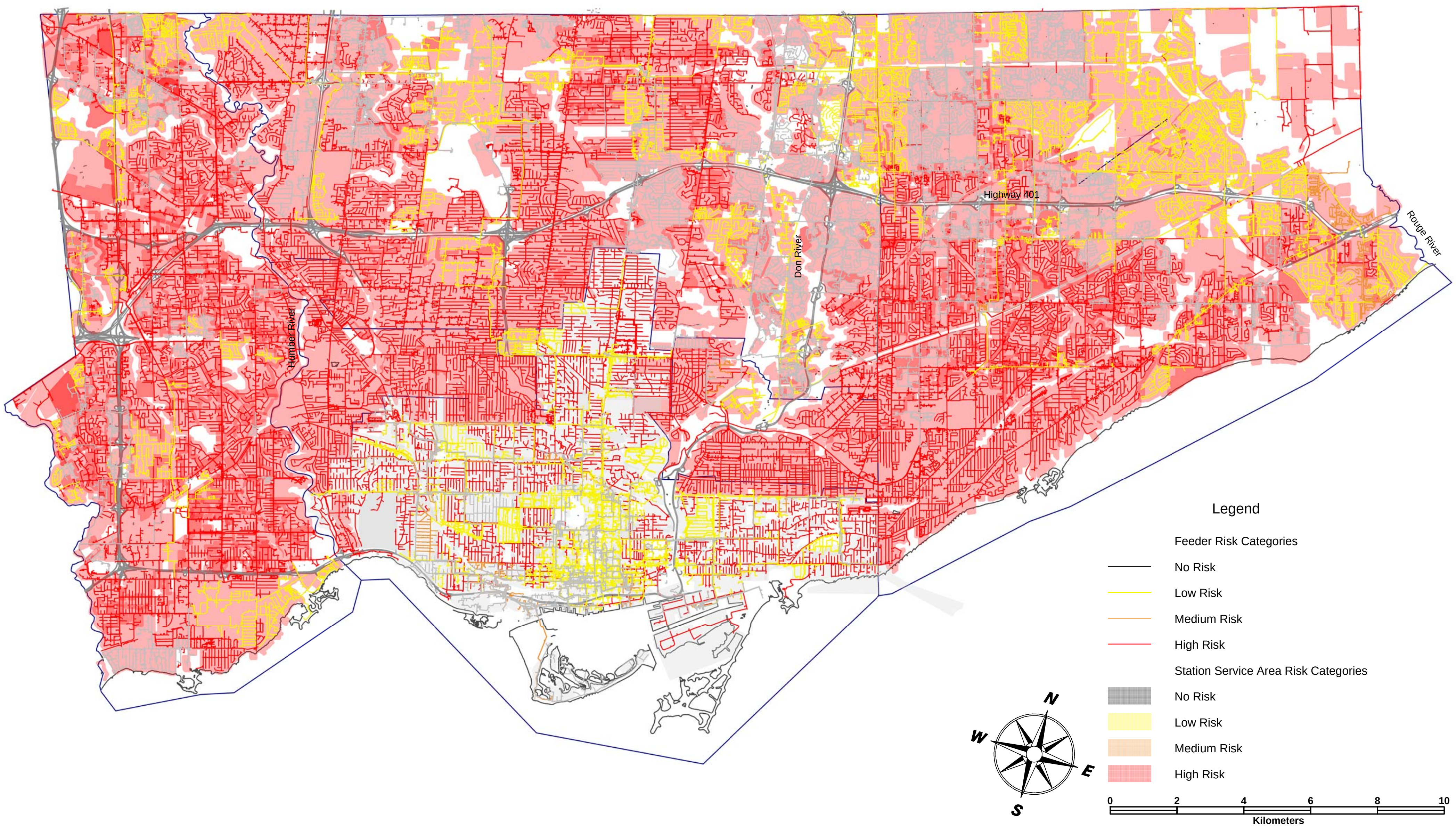
PIEVC Phase 2 Climate Change Risk Map by 2050

9. 15mm Freezing Rain/Ice Storm



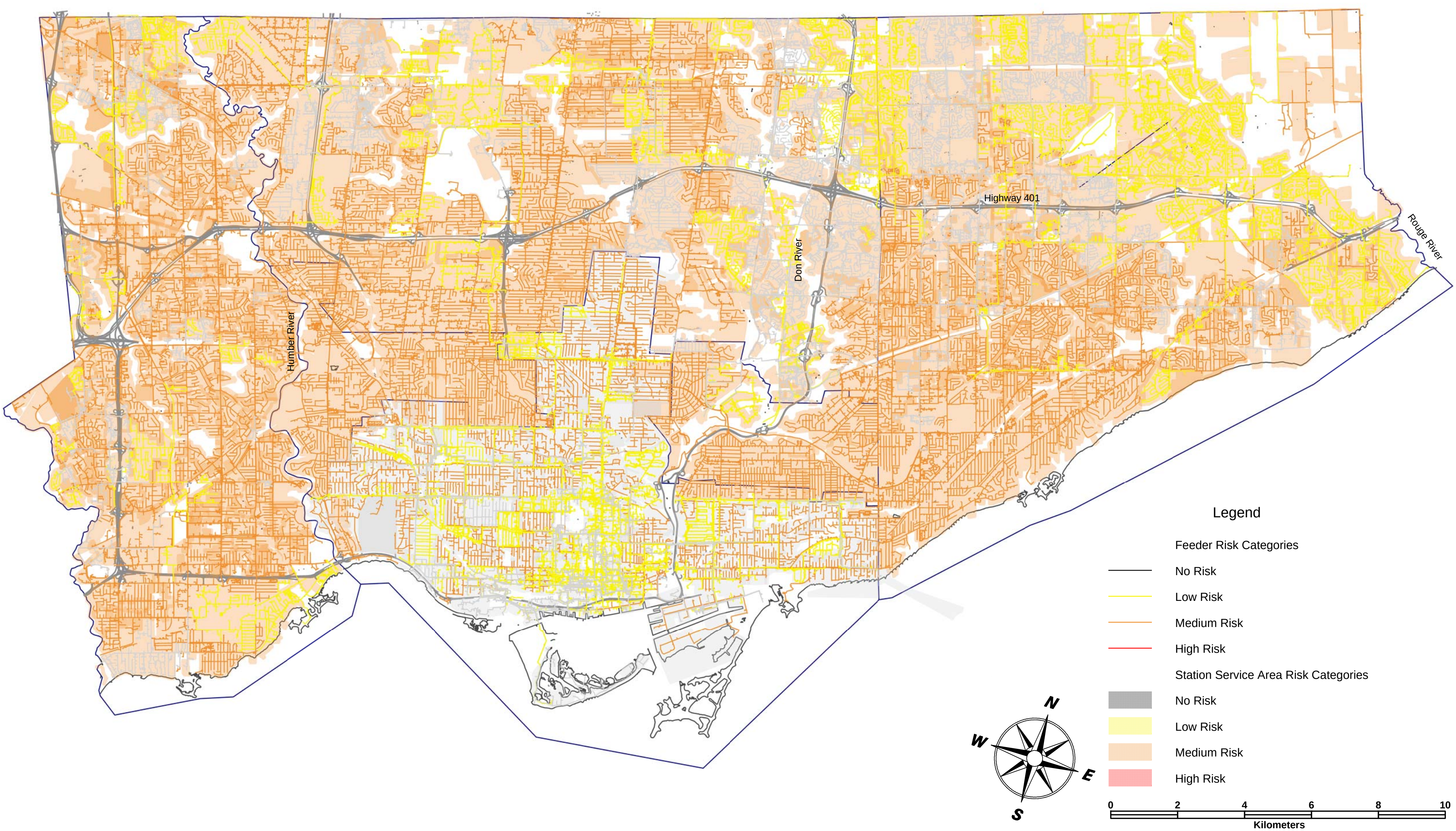
PIEVC Phase 2 Climate Change Risk Map by 2050

10. 25mm Freezing Rain/Ice Storm



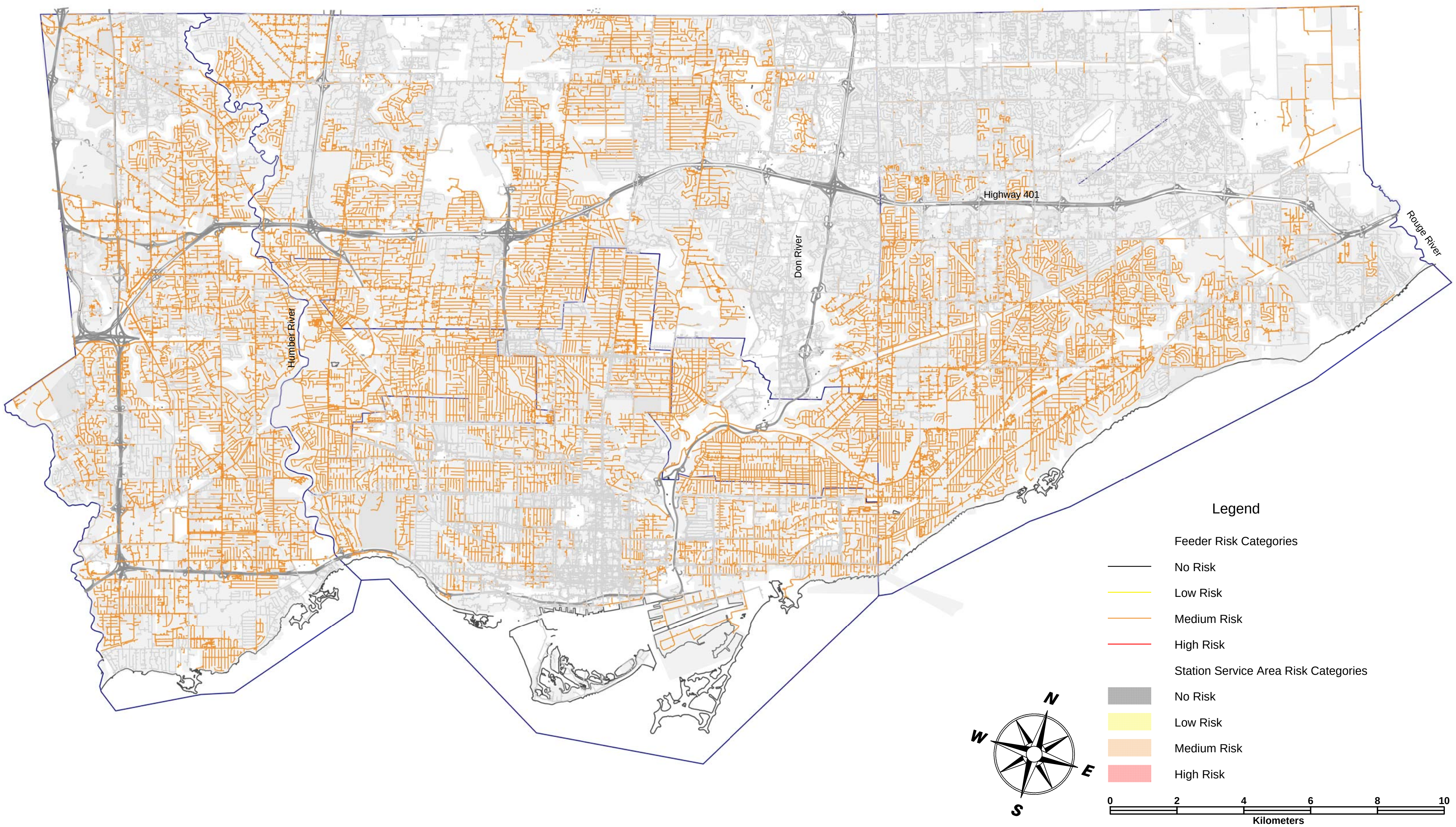
PIEVC Phase 2 Climate Change Risk Map by 2050

11. 60mm Freezing Rain/Ice Storm



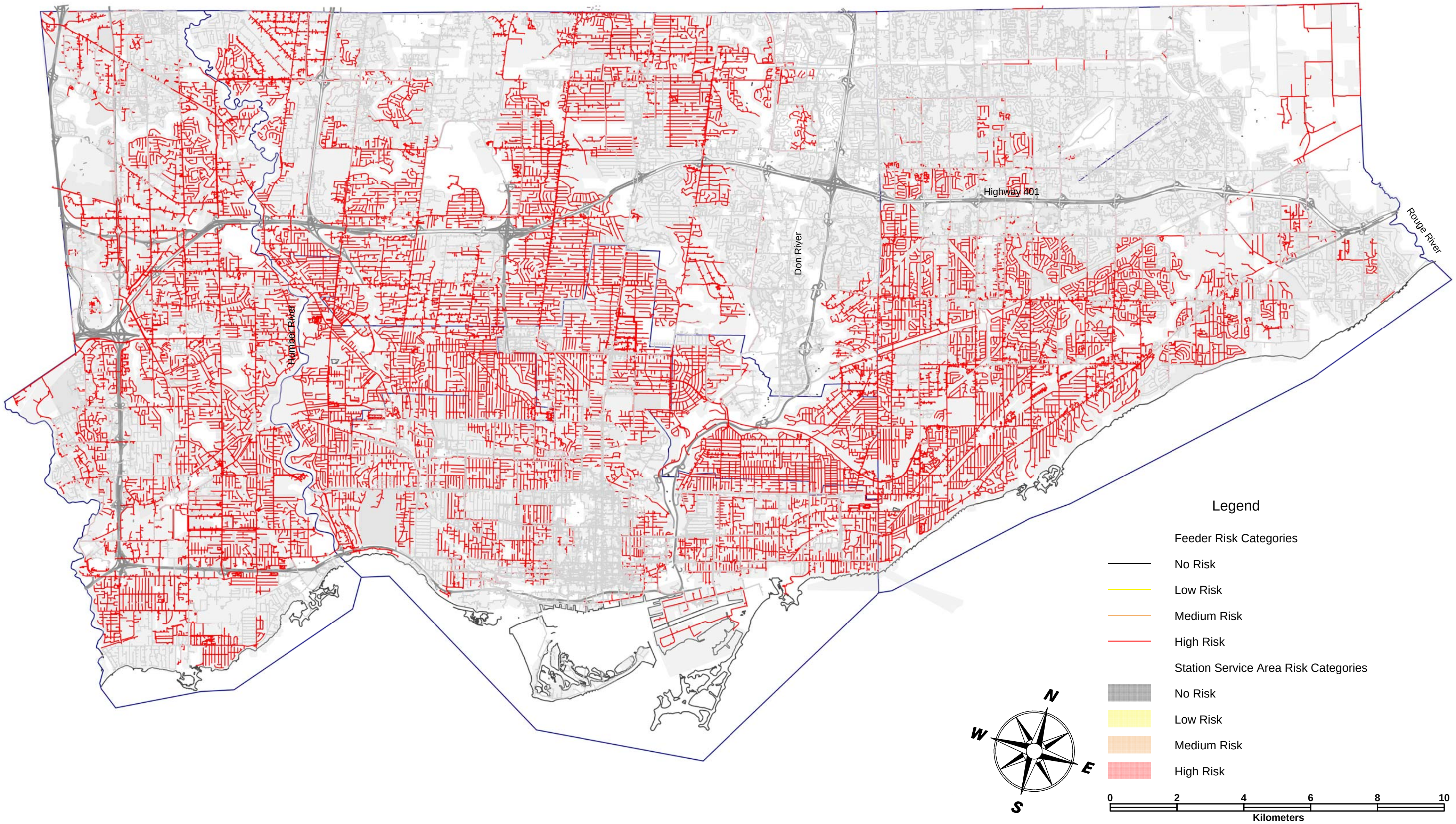
PIEVC Phase 2 Climate Change Risk Map by 2050

12. High Winds Greater Than 70km/h



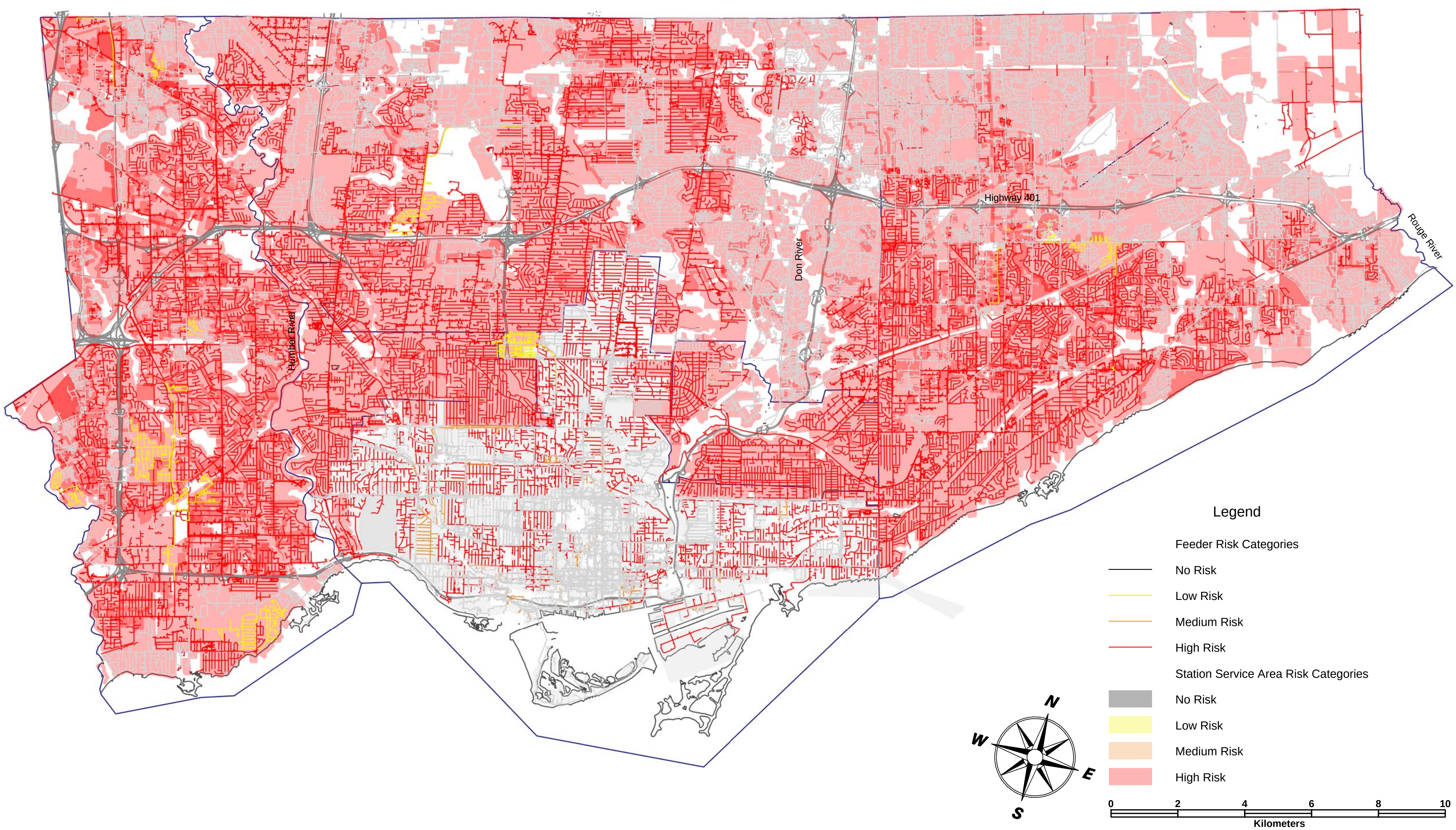
PIEVC Phase 2 Climate Change Risk Map by 2050

13. High Winds Greater Than 90km/h



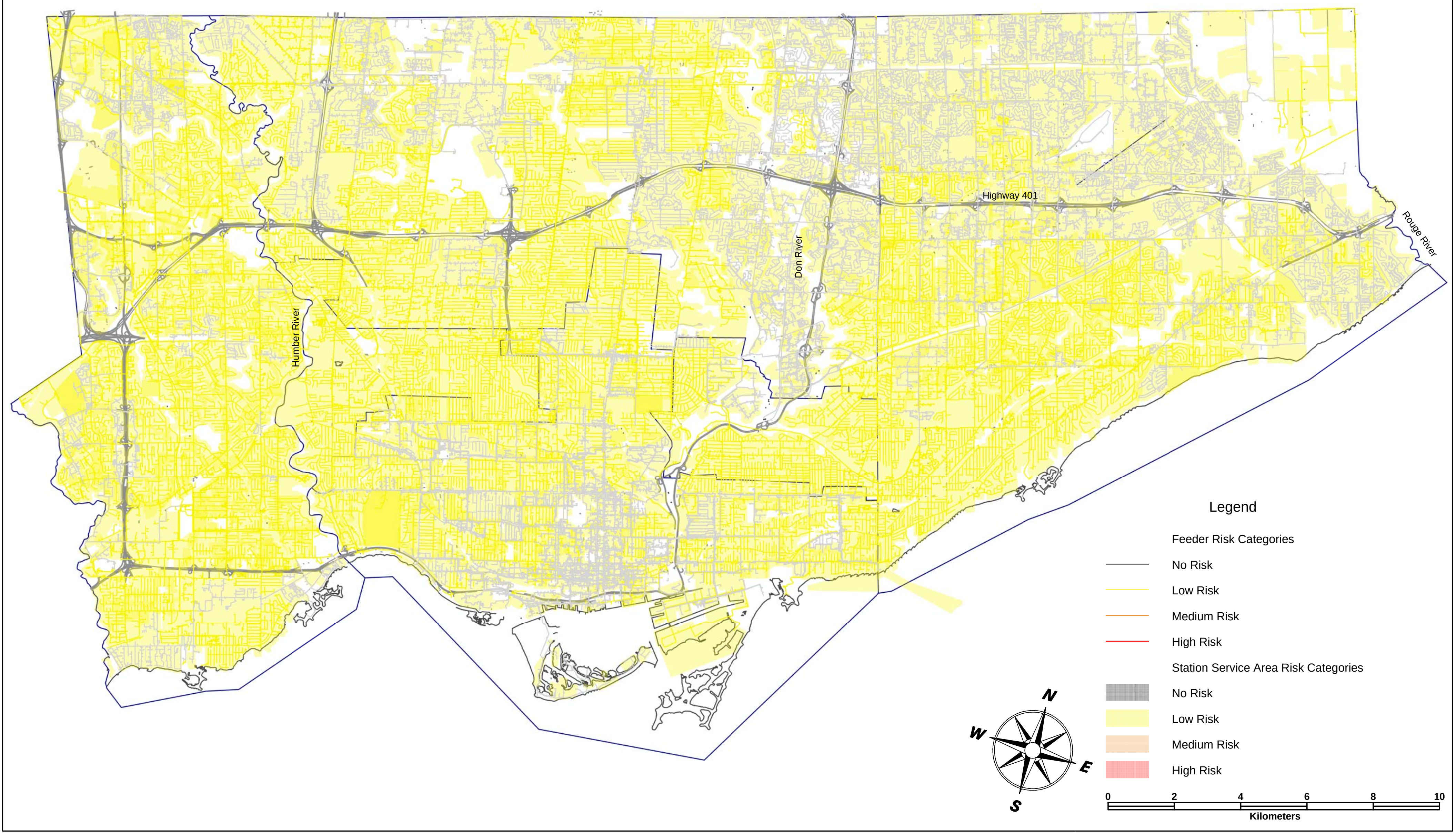
PIEVC Phase 2 Climate Change Risk Map by 2050

14. High Winds Greater Than 120km/h



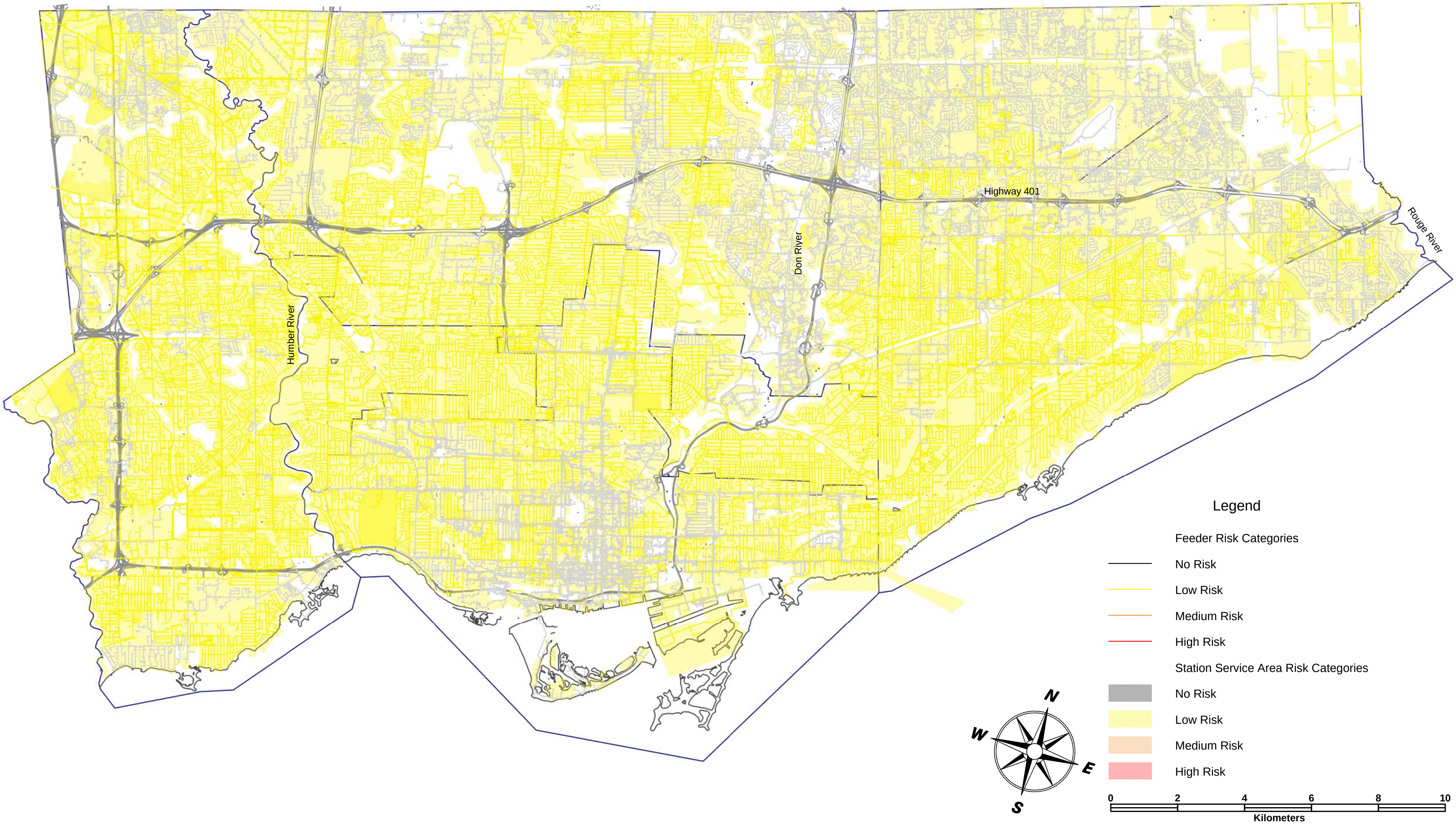
PIEVC Phase 2 Climate Change Risk Map by 2050

15. Tornadoes EF1+



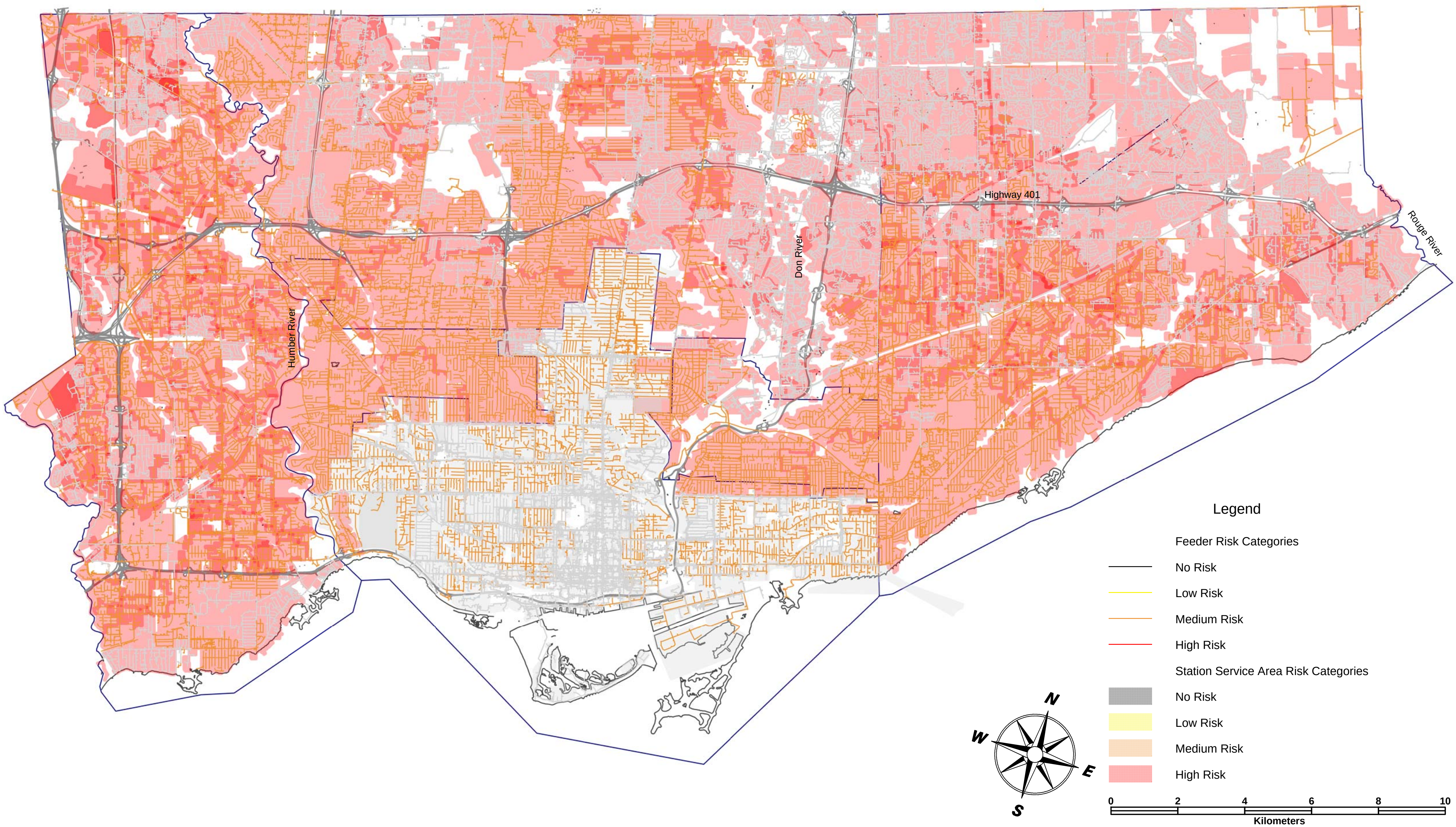
PIEVC Phase 2 Climate Change Risk Map by 2050

16. Tornadoes EF2+



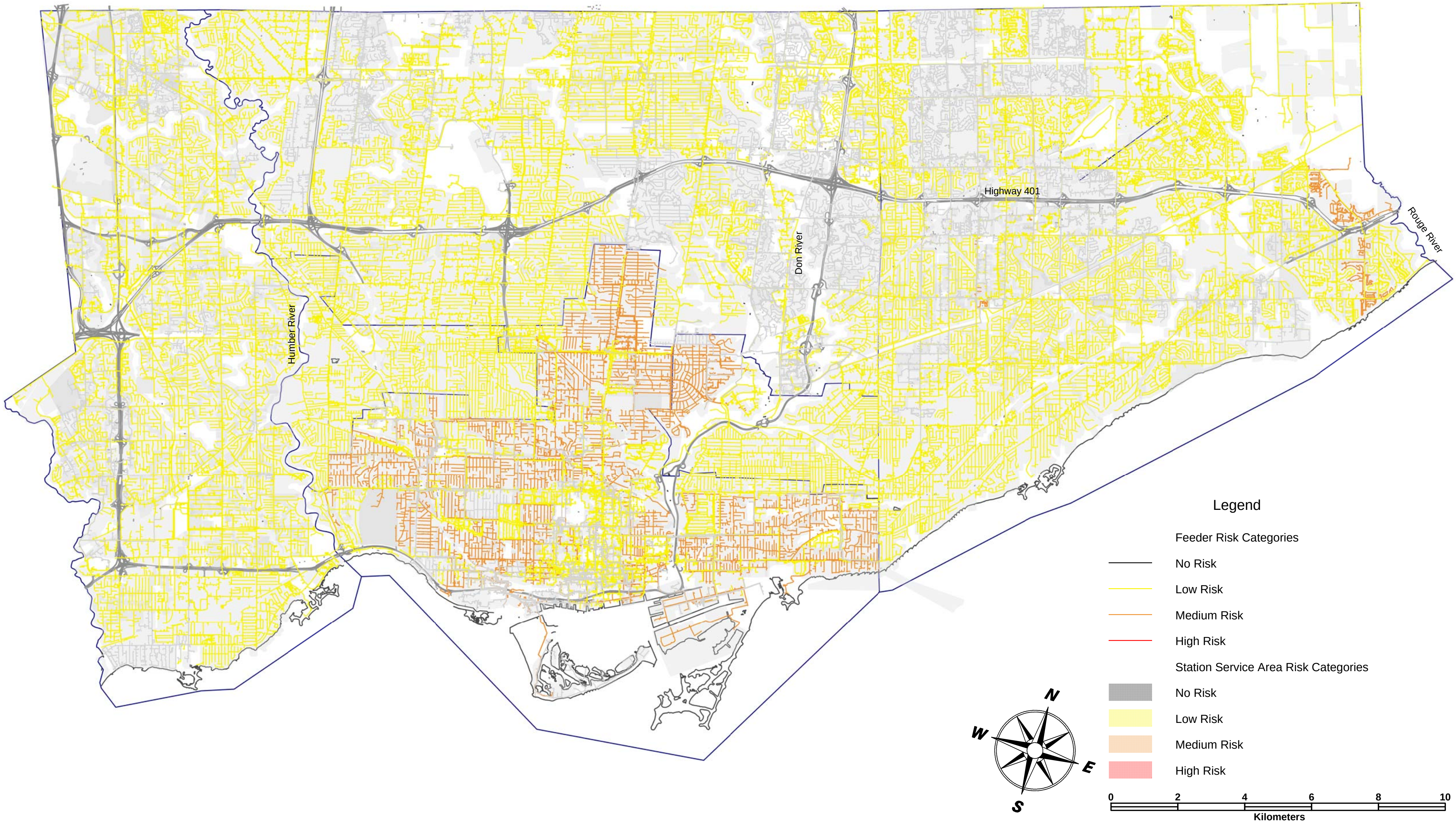
PIEVC Phase 2 Climate Change Risk Map by 2050

17. Lightning



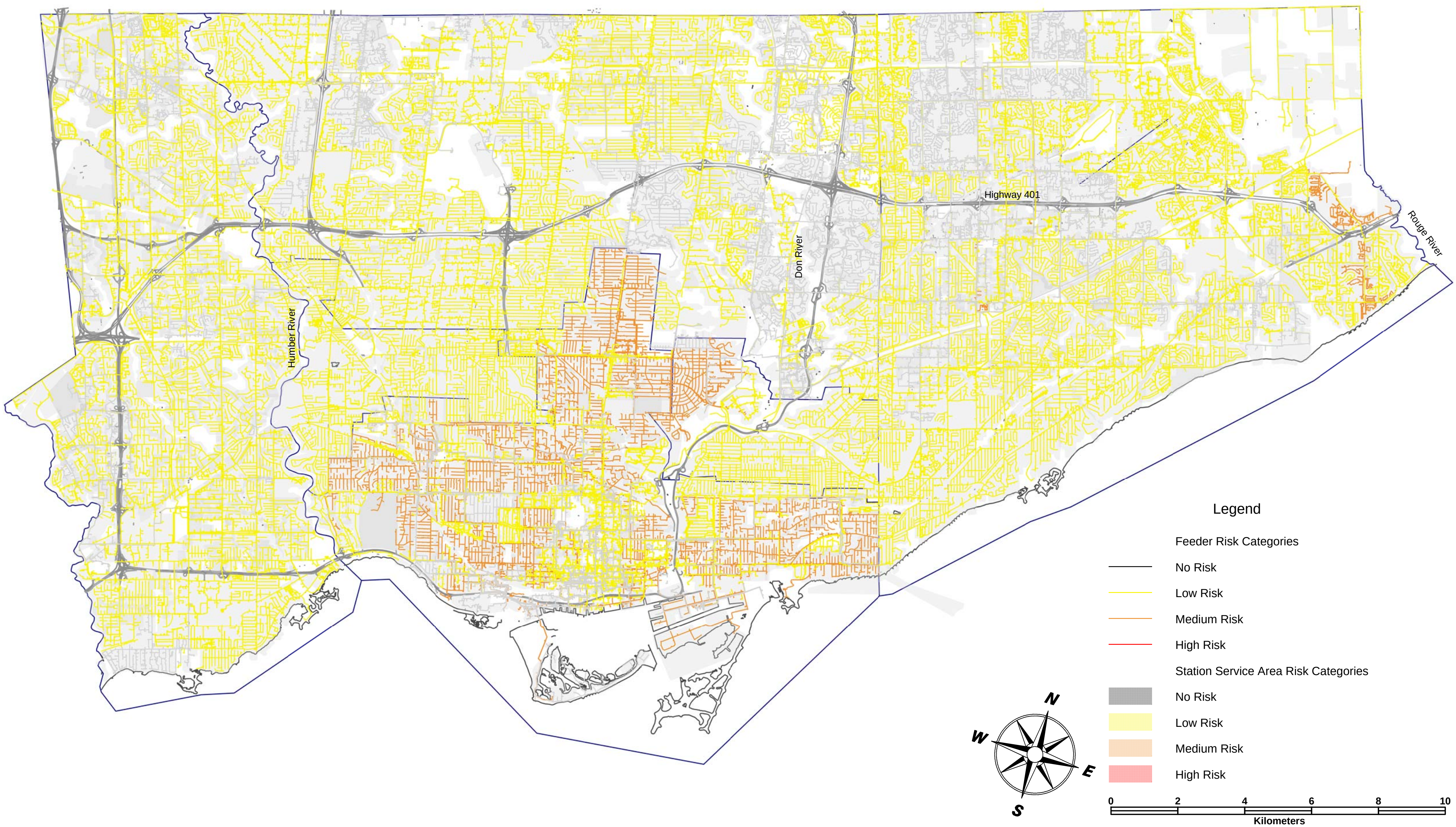
PIEVC Phase 2 Climate Change Risk Map by 2050

18. Snow >5cm



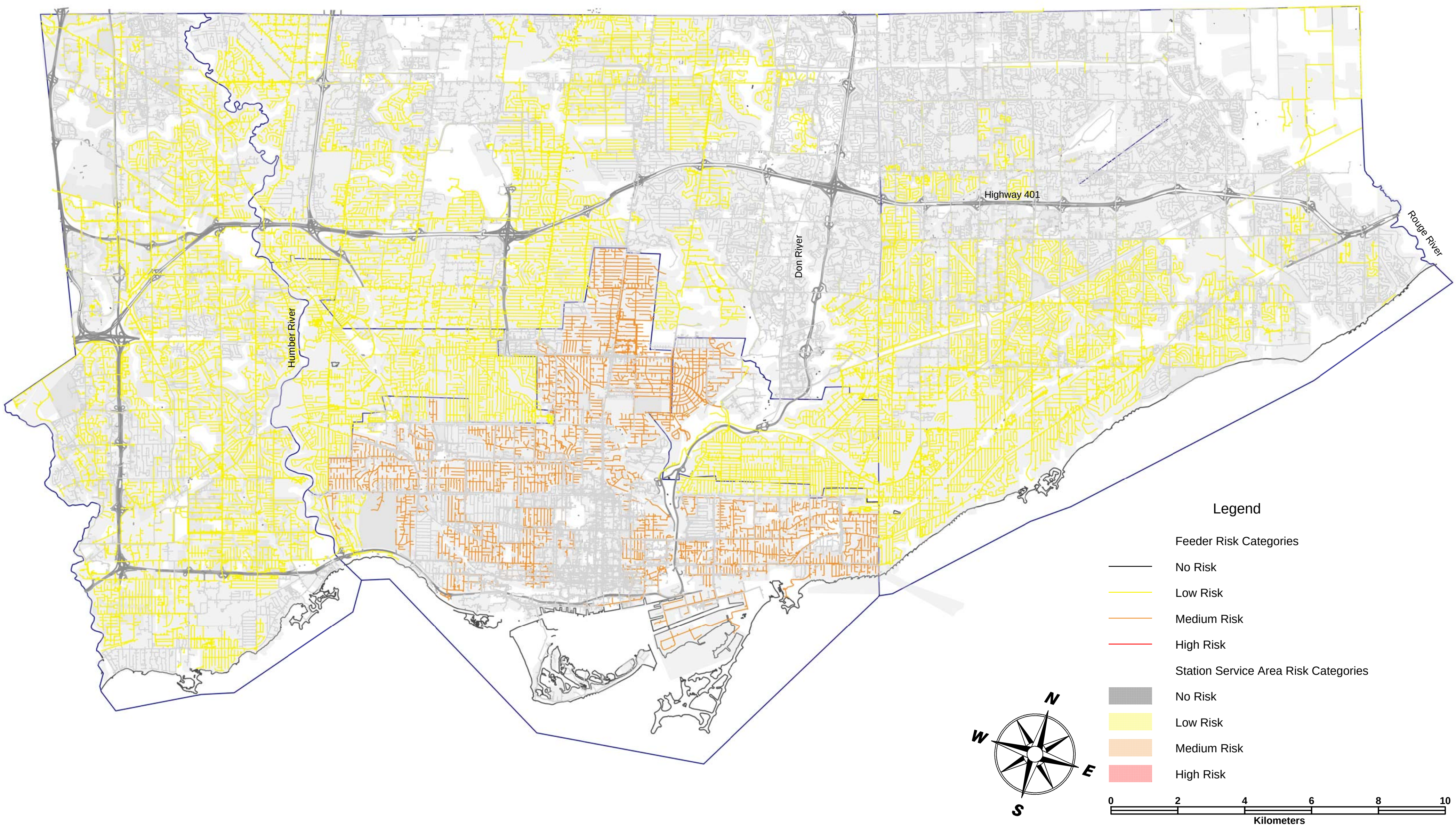
PIEVC Phase 2 Climate Change Risk Map by 2050

19. Snow >10cm



PIEVC Phase 2 Climate Change Risk Map by 2050

20. Extreme Cold Weather



Appendix F
Load Projection Methodology – Toronto Hydro

This information has been removed from the public version of this report

Appendix G
Engineering Analysis

Worksheet 4

The following appendix provides details about the estimation and calculation of the various load and capacity factors used in the Engineering Assessment of medium risk climate/infrastructure interactions. AECOM has elected to present this material in the following section in lieu of worksheet 4 template of the PIEVC Protocol.

1.1 Engineering Analysis Method

The engineering analysis is presented according to the following structure:

1. # Climate parameter / infrastructure system or component

Results and consequences: a recapitulation of the risk scoring results (scores range from 1 to 49) and consequences from Protocol Step 3, risk assessment activity

Task 1: Total Load: The total projected load, $\mathbf{L_T}$, is the sum of three load parameters, $\mathbf{L_E + L_C + L_O}$

$\mathbf{L_E}$ **=** Existing load.

$\mathbf{L_C}$ **=** Changing climate load placed on the infrastructure components for the project time horizon (2030 – 2050).

$\mathbf{L_o}$ **=** Other projected change loads.

Task 2: Capacity: The total projected capacity, $\mathbf{C_T}$ is the sum of three parameters, $\mathbf{C_E - C_{\Delta E} + C_A}$

$\mathbf{C_E}$ **=** Existing capacity.

$\mathbf{C_{\Delta E}}$ **=** Projected change (loss) in capacity arising from aging and normal wear and tear of the infrastructure components

$\mathbf{C_A}$ **=** Other projected additional capacity

Task 3: Vulnerability ratio: When possible, the vulnerability ratio is calculated

$$V_R = \frac{L_T}{C_T}$$

→ When $V_R > 1$, the infrastructure component is vulnerable

→ When $V_R < 1$, the infrastructure component has adaptive capacity

Task 4: Capacity Deficit: When the infrastructure is considered vulnerable, the projected capacity deficit, $\mathbf{C_D}$ is calculated, where possible. $\mathbf{C_D = L_T – C_T = L_T – (C_E + C_{\Delta E} + C_A)}$

Task 5: Conclusions from the Engineering Analysis: A statement is made as to whether the climate parameter-infrastructure interaction should be passed to Step 5 of the Protocol (i.e. making a recommendation to mitigate a vulnerability) or need not be considered further due to resilience to climate change.

When the engineering analysis cannot be completed, data gaps and possible types of additional studies are described that would facilitate the assessment of infrastructure vulnerability.

1.2 Resiliency or Vulnerability Evaluation

1. High temperature above 25°C and above 30°C / Transmission and Municipal stations and all Temperatures / Protection and Control systems

- **Results and consequences**: Risk scores of 14 and 21 depending on station excess capacity rating. Batteries lifespan is reduced. They are vital components because they are used as back-up power in case of power outages and emergencies and supplied DC current to many equipment in the stations.

- **Load**

$\mathbf{L_E}$ = Continuous loads (e.g. lighting) + Noncontinuous loads (e.g. fire protection systems) + Momentary loads (e.g. switchgear operations). A margin of 10-15% can be applied by the designer. Also the battery's rated capacity should be at least 125% (1.25 aging factor) of the load expected of its service life (IEEE-Std-485, 1997).

$\mathbf{L_C}$: Same loads will apply. Ventilation may be a little bit higher because of higher temperatures but the load will not change drastically.

$\mathbf{L_o}$: No other load to consider

$L_T = L_E + L_C + L_O = L_E + xL_E + 0$, where x is very small. Approximation: $L_T = L_E$

- **Capacity**

$\mathbf{C_E}$: The batteries are designed to operate at a temperature of 25°C. They are not installed in a temperature controlled room.

$\mathbf{C_E}$ capacity at 25°C = 100%. Expected service life = 25 years
The end of life of a battery is considered to be at 80% of its capacity (IEEE 485).

$\mathbf{C_{\Delta E}}$: Battery capacity at higher temperatures will actually increase if the cells are designed for a capacity of 100% at 25°C. From IEEE (IEEE-Std-485, 1997), "If the lowest expected electrolyte temperature is above 25 °C (77 °F), it is a conservative practice to select a cell size to match the required capacity at the standard temperature and to recognize the resulting increase in available capacity as part of the overall design margin". However, sustained high ambient temperatures result in reduced battery lifetimes.

$\mathbf{C_{\Delta E}}$ capacity over 25°C: more than 100%. Expected Service life will be less than 25 years. From Toronto Hydro's experience, some batteries have only lasted 10 years when they were expected to last 25 years.

$\mathbf{C_A}$: Battery designs are maintained at 100% capacity at 25°C.

$C_T = C_E - C_{\Delta E} + C_A = C_E - (-xC_E) + 0 = (1+ x)\, C_E$, but expected lifetime decrease.

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{Le}{(1+x)Ce} < 1 \; but \; life \; expenctancy \; decrease$$

- **Conclusion: Yes. Further action recommended.** Under higher temperatures, batteries will continue to be able to supply the necessary power to operate equipment (e.g. lighting, fire protection systems, switchgears). However, battery life may continue to be shorter than expected. Toronto Hydro has already encountered this problem, as batteries with a lifespan of 25 years are being replaced after 10 years.

2. High temperature above 35°C / Transmission stations

- **Results and consequences**: Risk scores of 21 and 28 depending of station excess capacity rating. Power transformers may be overloaded.

- **Load**

$\mathbf{L_E}$ = Maximum coincident load (year of design) + % of contingency at ambient temperature of 30°C
The actual peak load of the area is around 5 000 MVA.

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase caused to higher consumption of clients = bL_E

$\mathbf{L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E}$

- **Capacity**

$\mathbf{C_E}$: Horseshoe area station power transformer capacity is considered maximum with 100% of its total capacity at 30°C average ambient, and hottest point within power transformers not exceeding 110 °C. For Former Toronto area, the station capacity is restricted to no more than 95% of its total capacity because there are no station ties among transformer stations.
Expected service life = 20.55 years (180 000 hours).
Toronto Area transmission stations installed capacity is around 7 550 MVA.

$\mathbf{C_{\Delta E}}$: x%, where x is less than 100. According to IEEE (IEEE-Std_C57.91, 2012) the associated maximum air temperature should not be more than 10°C above the average ambient air temperature for air-cooled transformers (40°C). Station capacity at higher temperatures (e.g. 35°C) will be lower than at design temperature (30°C ambient) because the hottest point within power transformers has to be maintained below 110°C. Same expected service life if the load is adjusted (i.e. decreased) to meet these temperature restrictions. There x% at maximum temperatures above 35°C will not be large.

$\mathbf{C_A}$: Additional capacity will depend on the station. Some transmission stations will have added capacity by the end of the study period due to planned or anticipated upgrades, while others will not. The added capacity was evaluated within the risk assessment. “Good” rating mean that the transmission stations will have a greater future capacity margin, while “moderate” and “low” ratings mean stations will have less of a future capacity margin. From an overall systems standpoint, the worst case scenario is equivalent to no additional capacity added.

$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + 0 = (1 - x)\, C_E}$ **= Approximation** $\mathbf{C_T \approx C_E}$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a+b)Le}{Ce} = \frac{Load\ growth\ rate\ \times 5000\ MVA}{7550\ MVA}$$

Value of (1+ a + b) = Toronto Hydro could estimate a mean load growth rate for the study period.

- **Capacity deficit**

$\mathbf{C_D = L_T - C_T = (1 + a + b)\, L_E - (1\text{-}x)\, C_E}$.

The capacity deficit can’t be calculated because the load growth rate for the study period is not known.

- **Conclusion: Additional study recommended, conclusions for high temperature and power transformers also apply (see Chapter 7).** Transmission station designers will need to take into account the significant increase in days with maximum temperatures above 35°C, which reduces station capacity while, on the other hand, experiences an increased load demand. At the moment, no load growth rate for the period of this study was estimated. This could be calculated in further studies. The recommendations given in Chapter 7 for transmission stations and maximum temperature above 40°C / average temp above 30°C apply to this interaction.

3. High temperature above 40°C and Average temperature > 30°C / Transmission stations

- **Results and consequences**: risk score of 35 for transmission stations which have good future capacity (excess capacity) in the Horseshoe Area. Transmission stations with low future capacity ratings scored a high risk. Power transformers will be overloaded.

- **Vulnerability Ratio:** Refer to parameter #2.

- **Conclusion: Further action recommended**. Most of the transmission stations considered in this study were judged to be vulnerable (high risk rating) to high temperatures. The stations in the Horseshoe received a medium-high risk score (35) due to the application of the concept of excess capacity, which is qualitative and notional (refer to the **Appendix F**). As such, it is recommended that transmission stations receiving a medium-high risk score be considered vulnerable to extreme high temperatures as part of a consistent pattern of risk. This will also help Toronto Hydro to adopt a consistent approach in the design, operations and maintenance of stations.

4. Heat wave (+30°C) and High nighttime temperatures (+23°C) / Transmission stations

- **Results and consequences**: risk rating of 21, 28 and 35 depending of station capacity rating by 2050. Power transformers may be overloaded.

- **Load**

$\mathbf{L_E}$ = Maximum coincident Load (year of design) + % of contingency at ambient temperature of 30°C

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase caused to higher consumption of clients = bL_E

$\mathbf{L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E}$

- **Capacity**

$\mathbf{C_E}$: Horseshoe area station power transformer capacity is considered maximum with 100% of its total capacity. For Former Toronto area, the station capacity is restricted to no more than 95% of its total capacity because there are no station ties among transformer stations.
Expected service life = 20.55 years (180 000 hours).

$\mathbf{C_{\Delta E}}$: x%, where x is lower than 100. Power transformers can operate at temperature above 30°C, but long periods of high temperature can affect the equipment, such as when night time temperatures are high. The power transformer has no time to cool.

$\mathbf{C_A}$: Additional capacity will depend on the station. Some transmission stations will have added capacity by the end of the study period due to planned or anticipated upgrades, while others will not. The future capacity was evaluated within the risk assessment. “Good” rating mean that the transmission stations will have a greater future capacity margin, while “low” rating means stations will have less of a future capacity margin. From an overall systems standpoint, the worst case scenario is equivalent to no additional capacity added.

$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + 0 = (1 - x)\ C_E}$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a+b)Le}{(1-x)Ce} = \frac{Load\ growth\ rate\ \times 5000\ MVA}{(1-x)7550\ MVA}$$

Value of (1+ a + b) = Toronto Hydro could estimate a mean load growth rate for the study period.

Value of (1-x) = The loss of capacity is highly variable. It will not only depend of the maximum temperatures but also of the minimum temperatures. If the minimum temperature stays high during many days the power transformers will have no time to cool and its capacity will have to be reduced. High nighttime is important in that sense.

- **Capacity deficit**

$C_D = L_T – C_T = (1 + a + b) L_E – (1-x) C_E.$

The capacity deficit cannot be calculated because the load growth and the loss of capacity are not known.

- **Conclusion: Additional study recommended, conclusions for high temperature and power transformers also apply (see Chapter 7).** Consecutive days with high temperatures and high night time will increase over the study period. For example, high nighttime temperatures will go from 0.7 day/year to 7 days/year in 2030 to 16 days/year in 2050. Power transformers are vital equipment in the distribution of electricity and high temperatures have a significant impact on the capacity of the transformers. For these reasons, the conclusion of this report for temperature above 40°C and for high daily average temperature>30°C are also relevant to the heat wave and high nighttime temperature parameters. A load growth rate could be calculated for a better evaluation of impacts.

5. Freezing Rain/Ice Storm 60 mm ≈ 30 mm radial (major outages) / Transmission stations and Municipal stations

- **Results and consequences**: risk rating 28
  Outgoing lines (overhead) could fall down

- **Load**

L_E = Actual load is equal to the actual number of days of freezing rain

L_C = The load due to the freezing rain will slightly increase, $L_C = aL_E$, where ''a'' is a % of increase (small)

L_o = N/A

$L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E \rightarrow L_T > L_E$

- **Capacity**

C_E: The overhead power lines in the Toronto area are designed based on the CSA standard 22.3. Loads and load combinations correspond to so-called "Heavy Loading" specified in Table 30 of the CSA standard: wind of 400 Pa, 12.5 mm ice, -20°C temperatures.

$C_{\Delta E}$: It is assumed that the capacity will remain the same if the design criteria are not changing. $C_{\Delta E} = 0$

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A = C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{Ce} > 1\text{, the infrastructure is vulnerable}$$

- **Capacity deficit**

$C_D = L_T – C_T = (1 + a) L_E – C_E.$

- **Conclusion: Further action recommended.** The probability of occurrence of a heavy freezing rain event of 60 mm is relatively low in the future (8 – 25% probability of occurrence over the 35 year study period). However, this this interaction is part of a similar pattern of vulnerability as 25 mm freezing rain events (design capacity). Therefore, solutions for 25 mm events also relevant to mitigating heavy freezing rain events of ~ 60 mm.

6. High temperature (+35°C,+ 40°C, average temperature > 30°C, heat wave, high nighttime temperatures) / Municipal stations

- **Results and consequences**: 21, 28, 35. Medium to high medium risks.
  Consequences: Power transformers may overload.

- **Load & Capacity:** Same assumptions as for the power transformers in the transmission stations.
  The load will increase because of warmer temperatures. The capacity will decrease because of power transformers low ability to withstand hot temperatures for extended periods.
  Added capacity: Many Toronto Hydro to Toronto Hydro stations which interconnect the 4.16 kV power lines, will progressively be replaced by converted lines at 13.8 kV. Most of the municipal stations will then be to interconnect voltage levels from 27.6 kV to 13.8 kV. It is assumed that added capacity during the study period will be low for the 27.6-13.8 kV / 4.16 kV stations. More capacity can be added to the 27.6 kV/13.8 kV stations and will be variable depending on the stations need.
  For Toronto Hydro to Private owner ship, added capacity is possible and will be very variable depending on Client's need.

  $L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E$
  $C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + yC_A$ where x is variable and y is small and variable$\rightarrow C_T < C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a+b)Le}{\mathrm{CE} - (\mathrm{xCE}) + \mathrm{yCA}} < 1$$

- **Conclusion: Further action recommended**. High temperature and combinations of high temperature, high average temperature, high nighttime temperature and high load demand will have consequences on the capacity of the power transformers and the cables. For Toronto Hydro to Private ownership stations, a case by case evaluation is recommended.

1.2.1 Underground and Overhead feeders

7. High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime / Underground feeders

- **Results and consequences**: risk ratings 14, 21 and 28. The high demand stresses cables and power transformers. More capacity was available in the horseshoe area giving slightly lower results.

- **Load**

$\mathbf{L_E}$ = Actual demand + % of contingency

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase because of higher electrical consumption of clients (more electronic devices) = bL_E

$\mathbf{L_T = L_E + L_C + L_O}$

- **Capacity**

$\mathbf{C_E}$: Actual design of cables and power transformers is based on the actual load plus a margin. For underground feeders in the dual radial system, feeder capacity equals 50% of load for two parallel feeders. IEC 60287 base maximum ambient temperature at 35°C and maximum ground temperature at 20°C (IEC-60287))

$\mathbf{C_{\Delta E}}$: XLPE cables have an expected life of 40 years (for concrete duct installations) and for PILC cables 75 years. These cables are today reaching their expected life because they were installed during the early 1900s (for PILC) and 1950s (for XLPE). They will be changed through testing or from failure, because even if the cables are old they could be still being in good conditions (Toronto Hydro - OM&A, 2014). However, with climate changes (higher temperature), these cables will be stressed more often. Aging processes will accelerate and reduce capacity. This is a highly variable factor and cannot easily be calculated.

$\mathbf{C_A}$: Added capacity will be done by Toronto Hydro. Underground planning group could estimate the projected capacity for the study period.

$\mathbf{C_T = C_E - C_{\Delta E} ? + C_A}$

- **Conclusion: Further action recommended.** The vulnerability ratio and the capacity deficit cannot be calculated because the projected load on cables is not known. However, it is projected that climate change related high temperatures could create higher demand for cooling, and may place greater stress on cables and lead to increasing occurrences of cable failures. Therefore, high heat impacts on cable was deemed to be a vulnerability.

8. Extreme rainfall / Underground feeders

- **Results and consequences**: risk rating of 12, 18, 24, 30
    a. Feeders: Water treeing of the cables, flooding (18-24);
    b. Nun-submersible equipment failure in vault type stations below ground (30 Horseshoe Area, 36 Former Toronto);
    c. Above ground stations, access could be limited (12);
    d. Network feeders: old N/W protectors are not submersible (30).

a. <u>Feeders: Water treeing of the cables, flooding (18 Horseshoe Area, 24 Former Toronto)</u>

<u>Water treeing refers to a partially conductive structure that may form, in the presence of water, within the polyethylene dielectric used in buried high voltage cables. […] Water trees begin as a microscopic region near a defect.</u> They then grow under the continued presence of a high electrical field and water. Water trees may eventually grow to the point where they bridge the outer ground layer to the center high voltage conductor, leading to complete electrical failure at that point (Wikipedia).

- **Load**

$\mathbf{L_E}$ = Actual demand + % of contingency

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase due to higher electrical consumption by clients (more electronic devices)= bL_E

$\mathbf{L_T = L_E + L_C + L_O}$

- **Capacity**

$\mathbf{C_E}$: Actual design of cables is based on the actual load plus margin. For the underground feeders in the dual radial systems, each feeder capacity is equal to the load x 2.

$\mathbf{C_{\Delta E}}$: Flooding and heavy soil moisture tends to reduce the dielectric strength of cables. This cannot be calculated as it is highly variable. *The aging mechanism of underground cables depends on factors that involve the cable characteristics, accessory characteristics, and operating conditions, different power cable systems will age in different ways*. *In fact, aging degradation, and failure mechanisms are statistical in nature.* (NEETRAC, 2010)

$\mathbf{C_A}$: Toronto Hydro shall have a planning procedure for increasing the capacity of their underground system in line with load growth.

- **Conclusion: Further action recommended.** The load can be calculated by Toronto Hydro's estimates. However, the capacity is very hard to define, as aging degradation depends on many factors. Nonetheless, in combination with high heat events, extreme rainfall impacts on underground cables was deemed a vulnerability.

b. Non-submersible equipment failure in vault type stations below ground in the Horseshoe Area (30) (Former Toronto has a high risk result)

- **Load**

$\mathbf{L_E}$ = 0.04 flood per year (over 100 mm + short duration).

$\mathbf{L_C}$ = 0, flood intensity is considered to be the same for a given event (100 mm rainfall), but it will occur with greater frequency. Another complicating factor is how local drainage conditions (area topography, sewer system changes, land use changes) may or may not change flood characteristics in below ground vaults. At the scale of the current study, site specific flooding characteristics are not considered.

$\mathbf{L_o}$ = N/A

$\mathbf{L_T = L_E + L_C + L_O}$ = L_E.

- **Capacity**

$\mathbf{C_E}$: Cannot work when flooded. Most of the vaults have pumps when they are deeper than the city sewers. Small shallow single phase vaults drain naturally to the sewers. Pumps usually work well. There is no specific information available on the capacity of the pumps, but they are assumed to function correctly, as there are no indications that pump capacity needs to increase.

$\mathbf{C_{\Delta E}}$: same as today. $C_{\Delta E} = C_{E1} - C_{E2} = 0$.

$\mathbf{C_A}$: No additional capacity required.

$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E}$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{Le}{Ce} = 1$$

Conclusion: Further action recommended. Without replacement of non-submersible equipment by submersible equipment, the performance of electrical equipment in below grade vaults will not change over time (i.e. non-functional when flooded) The planned conversion of non-submersible equipment to submersible types in flood prone areas will help reduce vulnerability. While Toronto Hydro is gradually replacing vault type non-submersible equipment with submersible versions, non-submersible vault type equipment is likely to remain in the system over the study period, and hence remain a vulnerability for Toronto Hydro.

c. Above ground stations, access to the station and to the station equipment could be limited due to localized flooding of streets around the station, or at the station itself

- **Results and consequences** Low –medium risk.

- **Conclusion: No further action required.** This impact does not relate to station load or capacity. The consequence is that the access to the vault stations or the stations equipment could be temporarily impeded. Impact is localized and temporary, and was not judged to warrant further action beyond current practices.

d. Network feeders: old N/W protectors are not submersible (30)

- **Conclusion: Additional Study Recommended.** The old N/W protector may not operate properly if flooded. A network protector automatically connects and disconnects its power transformer from the network when the protector relay detects that power starts flowing in a reverse direction, preventing back feed, which is a potential safety hazard. However a failure of the N/W protector will not mean an interruption to the customer, since network systems are highly redundant. Network protectors are overhauled on a three-year cycle.

  Installations of new N/W protectors are submersible but there are still many old N/W protectors in the systems, particularly in downtown. Further study could be undertaken to evaluate the cost of replacing old network protectors prior to the end of their expected lifecycle against the frequency and impact of old N/W protectors being flooded.

9. High winds (120 km/h) / Padmount stations on distribution network (Former Toronto)

- **Results and consequences**: risk rating 14. Flying debris could impact the equipment.

- **Vulnerability Ratio:** The consequence of high winds and structural loads from flying debris are difficult to establish in terms of the load and the capacity of padmount stations. It's an independent impact based on a statistical probability.

- **Conclusion: No further action required.** The damaged equipment will result in an overall or some loss of service capacity and function. However, it is judged that flying debris is too much of a random occurrence to warrant further action.

10. High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave / Overhead power lines (radial and loop)

- **Results and consequences**: risk ratings of 14, 21, 28, 35
  These 4 climate parameters have the same consequences: Overload of the ONAN power transformers and the overhead conductors.

- **Load**

$\mathbf{L_E}$ = Max load + % of contingency

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase because of load growth due to population growth = bL_E

$$\mathbf{L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E}$$

- **Capacity (ONAN power transformers)**

$\mathbf{C_E}$: 100% at 30°C average ambient + hottest point within transformer not exceeding 110 °C.

$\mathbf{C_{\Delta E}}$: x%, where x is lower than 100. Capacity at higher temperature will decrease, because the hottest point has to be kept under 110°C.[1]

$\mathbf{C_A}$: Additional capacity can be added by adding more power transformers on the lines.

$$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + C_A = (1 - x)\, C_E + C_A}$$

- **Capacity (overhead conductors)**

[1] For example: temperature of 40°C during 10 hours, the average load should not excess 80-85% of the nominal kVA.

C_E: 100% at 75°C for ACSR conductors and 25°C ambient (manufacturers' limits).
Effects of high temperature can results in the annealing[2] of aluminum used within ACSR and AAC conductors. This effect begins at 93°C for these types of conductors, and is a function of the magnitude of the temperature and the duration of the application (electrical power flow).

$C_{\Delta E}$: x%, where x is lower than 100. The added combination of high temperature and higher current flow will significantly reduce the capacity of the conductors.
Other impacts: loss of strength due to annealing, increase in sag.

C_A: Capacity can be added by using other or larger types of conductors. However, in some place it could be difficult to do so as it would means to redesign the existing lines and may result, for example, in the replacement of existing poles by stronger ones generating high costs.

$$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + C_A = (1 - x)\, C_E + C_A.}$$

The reduction of the capacity is difficult to calculate because of the great diversity of operating circumstances and loading of the entire system. However, calculations for critical areas, where added capacity can be difficult to do, should be done.

- **Vulnerability Ratio:** Cannot be calculated because too many variables are not known.

- **Conclusion: Further action recommended.** Higher temperatures will have impacts on the overall capacity of the power lines. In the downtown area, there are critical, constrained areas (i.e. built up zone) where added conductor/transformer capacity may be difficult to implement.

11. High nighttime temperatures / Overhead power lines (radial)

- **Results and consequences:** risk rating 14
  Overload of the ONAN power transformers

- **Load and Capacity:**
  Refer to the previous evaluation. However, the capacity of the power transformers will not be reduced as much as for higher daily maximum temperature. Therefore, $C_E = xC_E$, with x as a small value.

  High nighttime temperatures have consequences on the capacity of the power transformer to cool enough before being loaded the next day. Climate projections show a significant increase in the number of days with low night time temperatures ≥ 23°C. The actual design of power transformers can support this temperature limit. As such, this impact was judged as low.

- **Conclusion: No further action required.** Night time temperatures with minimum ≥ 23°C will not have big impacts on the delivery of electricity. However, it is important to note that combination events of high daily temperature and high night time temperature are a concern. This is taken into account under the parameter, average temperature over 30°C on a 24 h basis.

12. Freezing Rain - Ice Storm 15 mm and high winds 70 km/h / Overhead Feeders in Loop Configuration

- **Results and consequences**: risk ratings of 28, 35 Conductors (tree contacts).

- **Load:**

[2] Annealing is the metallurgical process where applied temperature softens hardened metal resulting in loss of strength. For overhead conductors, annealing can degrade the strength of aluminum wires used in ACSR and AAC conductors (PJM Overhead conductor Ad Hoc Committee, 2010)

L_E = the actual load is based on tree branches that usually start to break with a 15 mm of freezing rain.

L_C = freezing rain of 15 mm will happen a little bit more often for the study period (from 0.11/year to 0.12/year to 0.16/year). Hypothesis $L_C = L_E$

L_o = N/A

$L_T = L_E + L_C + L_O = L_E$.

- **Capacity :**

C_E: Actual overall ''capacity'' of the tree canopy in Toronto.

$C_{\Delta E}$: $C_{\Delta E} = C_{future} < C_E$. The future overall ''capacity'' will decrease (or vulnerability to damage will increase) because of new or exacerbated disease and pest conditions and possibly, because of the tree faster growth (extended growing season, more branches).

C_A: N/A

$C_T = C_E - C_{\Delta E}$

- **Vulnerability Ratio**
  - $VR = \frac{Lt}{Ct} = \frac{Le}{Ce - C\Delta E}, where\ \frac{Le}{Ce} = 1, as\ Ce - C\Delta E$ is smaller, V_R will be >1

- **Capacity deficit**

$C_D = L_T - C_T$ = It cannot be calculated because the future capacity of the trees is not known.

- **Conclusion: Further action recommended.** The risk assessment completed in step 3 for radial systems resulted in a high risk rating for this interaction. In overhead loop systems, it was hypothesized that their more redundant configuration would reduce customer interruptions, affect fewer clients or cause outages of shorter durations, thus yielding a high-medium risk rating of 35. However, freezing rain events are expected to occur slightly more often than it does currently by the end of the study horizon. The tree canopy may also be affected by new or increased disease threats and extended growing season. Conductors will also sag more due to more extreme weather (ice, warm weather, etc.) leading to more contacts with the tree branches. According to THESL (Toronto Hydro - OM&A 2014): "*Vegetation interference is one of the most common causes of power interruption*". Finally, freezing rain events tend to be widespread, and there is no reason to believe that both branches of an overhead loop circuit might not be equally susceptible to damage. For all of these reasons, all overhead power lines, irrespective of electrical configuration, were deemed as vulnerable.

13. Freezing Rain/Ice Storm 60 mm ≈ 30 mm radial (major outages) / Overhead lines (radial and loop)

- **Results and consequences**: risk rating 24, 28
  Overhead lines could fall down, salt contamination

- **Load**

L_E = Actual load is equal to the actual number of days of freezing rain

L_C = The load due to the freezing rain will slightly increase, $L_C = aL_E$, where ''a'' is a % of increase (small)

L_o = N/A

$L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E \rightarrow L_T > L_E$

- **Capacity**

C_E: The overhead power lines in the Toronto area are designed based on the CSA standard 22.3. Loads and load combinations correspond to so-called "Heavy Loading" specified in Table 30 of the CSA standard: wind of 400 Pa, 12.5 mm ice, -20°C temperatures.

$C_{\Delta E}$: It is assumed that the capacity will remain the same if the design criteria are not changing. **$C_{\Delta E}$ = 0**

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A = C_E$

- **Vulnerability Ratio**

$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{Ce} > 1$, the infrastructure is vulnerable

- **Capacity deficit**

$C_D = L_T - C_T = (1 + a)\, L_E - C_E$.

- **Conclusion: Further action recommended.** See explanation for freezing rain and stations (item 5 above).

14. Lightning / Overhead power lines (radial and open loop) and SCADA system

- **Results and consequences**: risk rating of 18, 24, 30, failure of equipment (localized).

- **Vulnerability Ratio:** In this case, the impact comes from a direct or indirect strikes and has no consequences on the load and capacity of the infrastructure.

- **Conclusion: Further action recommended.** It is difficult to predict the increase of lightning strikes for the study period; however it is interesting to note that the probability of a lightning strike in an area of 0,015 km^2 anywhere within the City of Toronto is very high for the study period. At the moment, the number of arrestors/km, lightning strike intensity and arrestor performance are not monitored by Toronto Hydro. In the absence of this information, and since lightning strikes are currently a frequent source of outages, lightning strikes were judged to be a continued vulnerability. Further studies could evaluate if the actual protection of overhead power lines is sufficient, or if investments for more protection needs to be made. Direct strike impacts can be studied with software (e.g EMTP), while indirect strikes can be calculated numerically.

15. Snow > 5 cm and Snow > 10 cm / Overhead power lines (radial)

- **Results and consequences**: risk ratings of 14, salt deposited on the roads can also accumulate on insulators from water evaporation and transport through the air, and can create a failure (reduce the effective insulation levels and can lead to insulator tracking, flashover and potential pole fires or switch with porcelain insulator failure).

- **Vulnerability Ratio:** In that case, the impact is indirect and has no consequences on the load and capacity of the infrastructure.

- **Conclusion: No further action required.** The number of snow days is highly variable. The trend seems to be decreasing, but snow days will still occur annually. During the workshop, Toronto Hydro mentioned having problems regarding insulator tracking leading to pole fires especially at higher voltages (13.8 kV and 27.6 kV) and switch failures. However, Toronto Hydro is already monitoring and dealing with this issue. From THESL's report (Toronto Hydro - OM&A 2014): *to mitigate the risk of contamination and insulator tracking, insulators at the highest risk locations are washed twice a year.* Furthermore, recall that porcelain insulators are being progressively replaced by polymer insulators. *Polymer insulators are hydrophobic, and are not susceptible to the same failure mode due to contamination. […] Regular maintenance enables the detection and prediction of common failure modes. One such mode is the failure of switch's porcelain insulators. […] Porcelain switches pose high safety risks due to their susceptibility to contamination build-up and electrical tracking, which can lead to cracking […] posing a safety risk to employees or members of the public below.* As older porcelain insulators are being replaced by polymer insulators, it was judged that no further action than what is currently underway is required.

1.2.2 Civil structures

16. Extreme Rainfall, Freezing rain/Ice storm 15 mm & 25 mm & 60 mm (Combination of events) / Civil structures: Underground feeders (Former Toronto)

- **Results and consequences**: risk rating of 12, 14
  Accelerated corrosion of reinforcing bars and degradation of concrete in cable chambers and vaults.

- **Load**

L_E = Currently, civil structures (cable chambers, vaults) degrade at a pace related to the actual load (salt and moisture) related to current weather: Extreme Rainfall (100 mm) 0.04/year + Ice Storm (15 mm) 0.11/year + Ice Storm (25 mm) 0.06/year + Ice Storm (6hrs+) 0.65/year.

L_C = In the future, the structures will degrade more rapidly due to the more severe weather:
2030: Extreme Rainfall (100 mm) unknown but increase + Ice Storm (15 mm) 0.12/year + Ice Storm (25 mm) 0.07/year + Ice Storm (6hrs+) 0.73/year.
2050: Extreme Rainfall (100 mm) unknown but increase + Ice Storm (15 mm) 0.16/year + Ice Storm (25 mm) 0.09/year + Ice Storm (6hrs+) 0.94/year.

L_o: No other load.

$L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E$

- **Capacity**

C_E: actual capacity based on design criteria

$C_{\Delta E}$: As vaults are getting older, the capacity of the structures will decrease (approximately 60% of all network vaults will reach their expected life within the next ten years and 80% of network vault roofs and 60% of all cable chamber roofs are already beyond their useful life (Toronto Hydro - OM&A, 2014).

For the purpose of the study, we can then assume that $C_{\Delta E} = aC_E$, where ''a'' equal a percentage of diminution of capacity versus actual capacity

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A$ $= (1-a)C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{(1-a)Ce} > 1, \text{ the infrastructure component is vulnerable}$$

- **Conclusion: Further action recommended.** Vaults and chambers already suffering from degradation issues will deteriorate more rapidly over time. From THESL (Toronto Hydro - OM&A 2014): *As below-grade structures age, the greatest concern becomes structural strength. Structural deficiencies affecting vaults include degradation of concrete and corrosion of supports such as beams and rebar. Once degradation and* *corrosion sets in, conditions can deteriorate rapidly and in many cases from one season to the next. Of particular concern is the winter season when moisture and water enter in below*-grade *structures, freezes and thaws, and carries with it salt that has been used at grade to melt ice and snow.*

While maintenance can reduce the rate of deterioration, incidence of extreme rainfall, snowfall, freezing rain and the application of road salt will persist throughout the study period and continue to contribute to the premature aging of civil structures. While, it could not be determined in the study whether premature aging of civil structures will be exacerbated by a changing climate, this issue will persist over the study period and is therefore judged as an on-going vulnerability.

17. Snow > 5 cm and Snow > 10 cm / Civil structures: Underground feeders (Former Toronto)

- **Results and consequences**: risk ratings of 14, 21, Degradation of concrete in cable chambers and vaults.

- **Load**

L_E = Actually the civil structures (cable chambers, vaults) degrade at a rhythm caused by current climate.

L_C = The ''load'' will probably decrease. $-aL_E$

L_o = No other load.

$L_T = L_E + L_C + L_O = L_E - aL_E = (1\text{-}a)L_E$

- **Capacity**

C_E: actual capacity based on design criteria

$C_{\Delta E}$: As vaults age, the capacity of the structures will decrease (approximately 60% of all network vaults will reach their expected life within the next ten years and 80% of network vault roofs and 60% of all cable chamber roofs are already beyond their useful life, (Toronto Hydro - OM&A, 2014)).

For the purpose of the study, we can then assume that $C_{\Delta E} = bC_E$, where ''a'' equal a percentage of diminution of capacity versus actual capacity

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A$ $= (1\text{-}b)C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1-a)Le}{(1-b)Ce}$$, it is not possible to know if a will be < or > b

- **Conclusion: No further action required, but combinations of climates events require additional study.** As days with snow will probably decrease, the snow days alone were not judge to be a significant vulnerability. However, snow days will still occur over the study period, and in combination with extreme rainfall, freezes and thaw, freezing rain, and the continued application of road salt, premature degradation of civil structures was judged to be an ongoing vulnerability for Toronto Hydro.

18. Frost / Civil structures (overhead and underground feeders)

- **Results and consequences**: risk rating of 14, frost heave of civil structures

- **Vulnerability Ratio:** In the future, the ‘’load’’ will reduced as less frost days are expected. However, as vaults and as the foundations for concrete or steel poles age, the capacity of the structures will decrease.

  Conclusion: Further action recommended. Even if the frost threat is decreasing, it is noted that frost penetration will still occur during the study period with occasionally extreme weather. Since, Toronto Hydro already experiences problems with frost and its civil infrastructure, frost impacts were judged to be a vulnerability.

19. All Climate Parameters / Human Resources

- **Results and consequences:** risk ratings of 14 to 28, weather related impacts on safe site access, work conditions and travel

- **Conclusion: Further action recommended.** While occupational health and safety procedures will continue to be in place in the future, human resources will continue to be vulnerable to climate change related weather events due to the need to travel, access, and work on equipment in spite of the weather.

Appendix H
PIEVC Worksheets

Worksheet 1 and 2 have been removed from the public version of this report.

However, information on infrastructure can be found in summary form in Chapter 2 of this report. Climate information can be found in Chapter 3, and in Appendix B and Appendix C of this report.

Worksheet 3 information can be found in Appendix D.

Worksheet 4 information can be found in Appendix G.

Worksheet 5 information is contained within Chapter 7 of this report.

E Capital Expenditure Plan

E1 Capital Expenditure Plan Introduction

E1.1 Introduction

Section E details Toronto Hydro's 2020-2024 Capital Expenditure Plan. It consists of the following sections:

- **Section E1 – Capital Expenditure Plan Introduction:** Provides basic information about the expenditure plan, including drivers, expenditures by category, and associated performance measures.
- **Section E2 – Capital Expenditure Planning Process Overview:** Provides a detailed explanation of how Toronto Hydro's Business Planning Process, including customer engagement, and Asset Management Process (as described in Section D) were used to develop the 2020-2024 Capital Expenditure Plan.
- **Section E3 – System Capability Assessment for Generation Connections:** Provides information on the capability of Toronto Hydro's distribution system to accommodate renewable energy generation ("REG") and other distributed generation ("DG") connections.
- **Section E4 – Capital Expenditure Summary:** Provides a snapshot of Toronto Hydro's capital expenditures over a 10-year period from 2015 to 2024, including explanatory notes on material variances.
- **Sections E5-E8:** Provides detailed, program-specific justifications, and business cases for Toronto Hydro's capital expenditure plan in each of the System Access (E5), System Renewal (E6), System Service (E7), and General Plant (E8) categories.

The following is an introduction to the 2020-2024 Capital Expenditure Plan.

E1.2 2020-2024 Capital Expenditures

Toronto Hydro's capital programs are grouped into the following four categories, as prescribed by the Ontario Energy Board's ("OEB") Chapter 5 Filing Requirements for Electricity Distribution Rate Applications (July 12, 2018):

- System Access Investments (Section E5);
- System Renewal Investments (Section E6);
- System Service Investments (Section E7); and
- General Plant Investments (Section E8).

For categorization purposes, each program is assigned one or more drivers of work, including a single trigger driver (representing the catalyst for the investment) and typically one or more secondary drivers.[1] Programs are allocated to each of the four investment categories in accordance with their trigger drivers. A description of each trigger driver is provided in the table below.

Table 1: Investment Category Trigger Drivers

	Driver	Description
System Access	***Customer Service Requests***	The fulfilment of Toronto Hydro's obligation to connect a customer to its system. This includes both traditional demand customers and distributed generation ("DG") customers. The obligation to connect holds as long as there are no safety concerns for the public or employees and there is no adverse effect on the reliability of the distribution system. The utility undertakes expansion or enhancements to the system when a connection cannot be made with existing infrastructure.
	Mandated Service Obligation	Compliance with all legal and regulatory requirements and government directives.
System Renewal	***Functional Obsolescence***	The asset and/or its installation is no longer aligned to Toronto Hydro's processes and practices such that it can no longer be maintained (e.g. lack of vendor support) or utilized as intended to support the utility's operations.
	Failure	Asset or critical component failure has taken place and Toronto Hydro must respond reactively as part of its capital investment activities.
	Failure Risk	There is imminent risk of failure due to age or condition deterioration. The potential failures will result in significant reliability impacts to customers as well as potential safety risks to crew workers or to the public.
System Service	***Reliability***	Maintain or improve reliability at a local, feeder-wide, or system-wide level.
	Capacity Constraints	Expected changes in load will constrain the ability of the system to provide consistent service delivery and handle demand requirements.

[1] The list of capital investment drivers used in this application were developed based on the OEB's example drivers from Chapter 5 of the OEB's Filing Requirements.

General Plant	***Operational Resilience***	The ability to mitigate and recover from disruptions to core business functions.
	System Maintenance and Capital Investment Support	Required investments to support day to day business operational activities; sustaining operations by providing its employees with a safer environment to operate in an efficient and reliable manner.

Planned expenditures for the 2020-2024 period are presented by investment category in Table 2 below.

Table 2: Planned Capital Investment by Category ($ Millions)

Category	Forecasted Spend						
	Avg.	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
System Access	100.3	91.8	93.3	93.9	106.0	116.4	**501.4**
System Renewal	324.0	306.6	325.7	323.1	339.0	325.5	**1,619.9**
System Service	47.5	34.2	60.1	71.3	33.6	38.5	**237.7**
General Plant	84.9	78.8	93.7	89.0	77.7	85.2	**424.4**
Other	8.8	7.0	9.0	9.8	9.5	8.7	**44.0**
Total	**565.5**	**518.4**	**581.8**	**587.1**	**565.7**	**574.4**	**2,827.4**

To drive continuous improvement in its distribution planning and implementation work described in the four categories above, Toronto Hydro plans to track 15 utility-specific measures (as shown in Table 3) over the 2020-2024 period (in addition to the OEB's Distributor Scorecard measures and Electricity Service Quality Indicators). These measures reflect Toronto Hydro's Outcomes Framework (described in Exhibit 1B, Tab 2, Schedule 1), and represent its response to customer preferences communicated through formal and informal engagement (see Exhibit 1B, Tab 3, Schedule 1). By monitoring and managing these measures, the utility expects to drive continuous and sustained improvement across the organization through the 2020 to 2024 period.

Table 3: Toronto Hydro's 2020-2024 Custom Performance Scorecard

Toronto Hydro Outcome	Toronto Hydro's Custom Measures	Target
Customer Service	Customers on eBills	Improve
Safety	Total Recorded Injury Frequency	Maintain
	Box Construction Conversion	Improve
	Network Units Modernization	Improve
Reliability	SAIDI - Defective Equipment	Maintain
	SAIFI - Defective Equipment	Maintain
	FESI-7 System	Improve
	FESI-6 Large Customers	Maintain
	System Capacity	Maintain
	System Health (Asset Condition) – Wood Poles	Monitor
	Direct Buried Cable Replacement	Improve
Financial	Average Wood Pole Replacement Cost	Monitor
	Vegetation Management Cost per Km	Monitor
Environment	Oil Spills Containing PCBs	Improve
	Waste Diversion	Monitor

Section E2 provides a detailed discussion of how business planning (including Customer Engagement) and Toronto Hydro's asset management practices and methodologies produced the 2020-2024 Capital Expenditure Plan.

E2 Capital Expenditure Planning Process Overview

Section E2 provides a comprehensive overview of how Toronto Hydro developed its 2020-2024 Capital Expenditure Plan, including the pacing and prioritization decisions that the utility made to support the delivery of outcomes that align with customer needs and preferences. This section is organized into the following three areas:

- **Section E2.1** describes the sequence of business planning activities that produced the Capital Expenditure Plan, and provides an overview of the utility's key considerations and decisions during this process.
- **Section E2.2** focuses on the outputs of Toronto Hydro's asset management and operational planning processes (described in Section D) and how they influenced the pacing and prioritization of the capital expenditure plan.
- **Section E2.3** describes the results of the utility's planning-specific Customer Engagement and how Toronto Hydro developed a plan that is aligned with and responsive to customer needs, preferences and priorities.

Fully detailed justifications and business cases for all of Toronto Hydro's planned capital expenditures can be found in the capital program sections in E5 through E8.

E2.1 Capital Planning in Business Planning

Toronto Hydro's 2020-2024 Capital Expenditure Plan was an output of its outcomes-oriented, customer-focused business planning activities. The plan was derived from the utility's distribution system asset management processes and other operational planning activities, including outputs from the Investment Planning & Portfolio Reporting ("IPPR") process described in Sections D1 and D3. A high-level view of business planning as it relates to the Capital Expenditure Plan is shown in Figure 1.

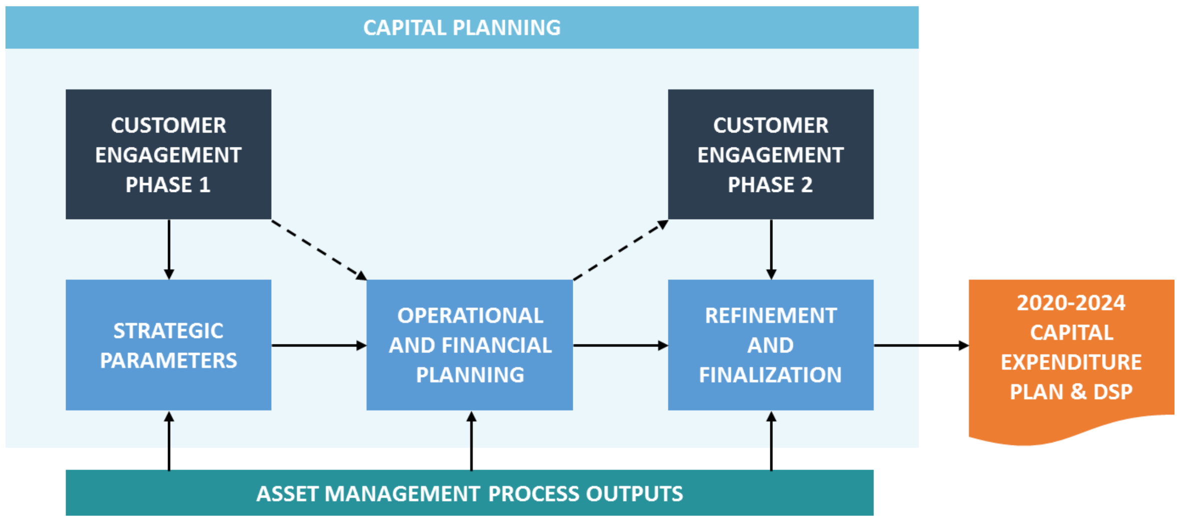


Figure 1: Capital Planning in Business Planning

The following sections provide an overview of how the elements of business planning came together to generate the capital plan that forms the basis of Toronto Hydro's 2020-2024 Distribution System Plan.

E2.1.1 Customer Engagement and Strategic Parameters

Toronto Hydro began business planning by engaging customers (i.e. Phase 1 of Customer Engagement) and using the feedback received to help set the initial strategic parameters for the business planning horizon. Feedback from customers was that price, reliability, and safety were their top three priorities. Overall, most customers preferred prices be kept as low as possible while maintaining average reliability performance and improving reliability for customers experiencing below-average service. [1]

With consideration for customers' priorities and preferences and other inputs (discussed below), Toronto Hydro set the following strategic parameters for the capital plan:

1) **Price Limit:** Toronto Hydro set an upper limit of 3.5 percent as a cap on the average annual increase to base distribution rates.[2]
2) **Capital Budget Limit:** Toronto Hydro set an upper limit of $562 million for the average annual capital plan budget, which corresponded with capping infrastructure and operations

[1] The results of Customer Engagement, Phase 1, are discussed in detail in Section E2.3.
[2] As calculated for the monthly bill of a Residential customer using 750 kWh.

spending predominantly at sustainment levels. As discussed in Section E2.2, this upper limit was based on an assessment of system and operational needs as derived from the utility's asset management processes, reflecting the need to, at a minimum, meet the utility's service obligations, maintain average reliability performance, and sustainably manage asset risk over the long-term while mitigating material safety and environmental risks.

3) **Performance Objectives:** Toronto Hydro developed an Outcomes Framework that aligned with the utility's corporate strategic pillars and the *Renewed Regulatory Framework*, establishing a lens through which the utility could express its plans and performance in terms that demonstrate value for customers, and are meaningful to its operations. This framework is summarized in Figure 2, below.

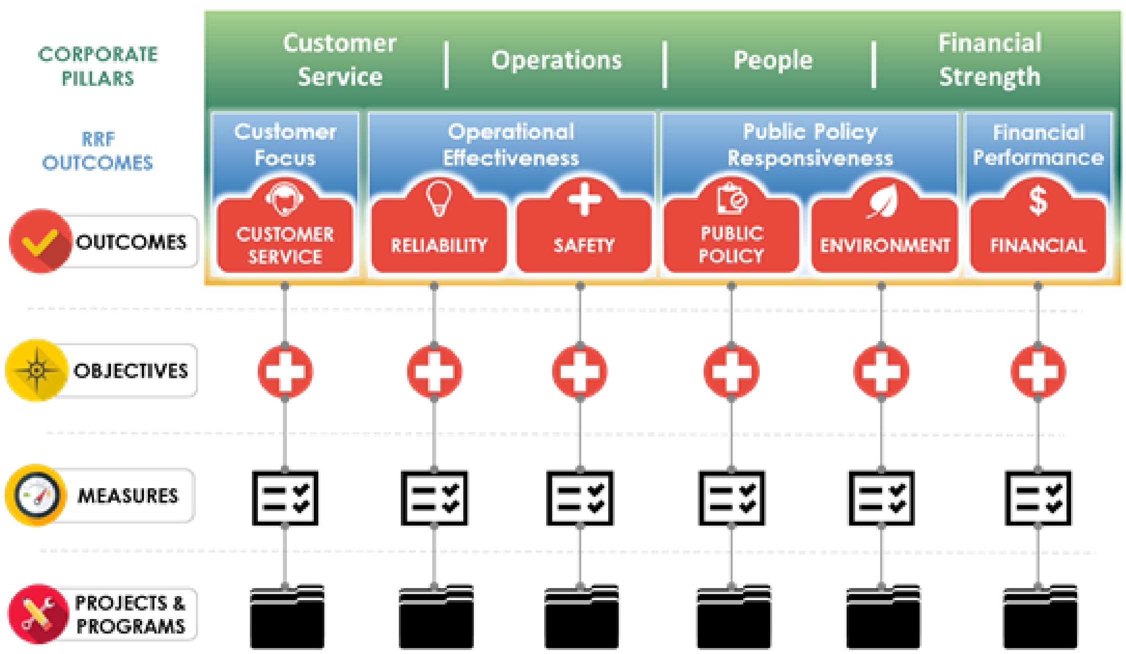


Figure 2: Toronto Hydro's Customer-Focused Outcomes Framework[3]

In developing these strategic parameters, Toronto Hydro considered a number of inputs, including:

- as mentioned above, customer priorities and preferences identified in Phase 1 of the utility's planning-specific Customer Engagement activities;

[3] The RRF Outcomes are aligned alongside Toronto Hydro's Outcomes based on the definitions provided by the OEB in the Utility Rate Handbook. It should be noted that Toronto Hydro's Financial outcome includes cost-related components that the OEB would classify within the Operational Effectiveness outcome.

- customer needs and preferences as understood by the utility through routine and ongoing engagement with customers and community stakeholders;
- historical and forecast system performance;
- projected system use profiles and pressures;
- long-term asset stewardship needs;
- safety and environmental risk assessments;
- evolving business conditions and the emergence of new technologies;
- resiliency and business continuity risks, including climate change risk;
- evolving regulatory and compliance needs;
- workforce needs and challenges;
- inflationary cost pressures, including ongoing and anticipated upward pressure on construction costs in Toronto;
- total cost benchmarking; and
- distributor scorecard benchmarking.

To further inform the selection of price and capital budget limits, Toronto Hydro performed a high-level scenario analysis based on preliminary planning scenarios for each capital program. These scenarios – described further in Section E2.2 – reflected a baseline “sustainment” level of system investment, an “improvement” level, and an “accelerated improvement” level. Figure 3, below, illustrates what the total capital expenditure plan would look like if Toronto Hydro had selected exclusively from either the sustainment, improvement, or accelerated improvement options for every investment program. The three lines represent a fully unconstrained budget on the high-end, a minimal system sustainment budget on the low end, and a mid-point budget in between.

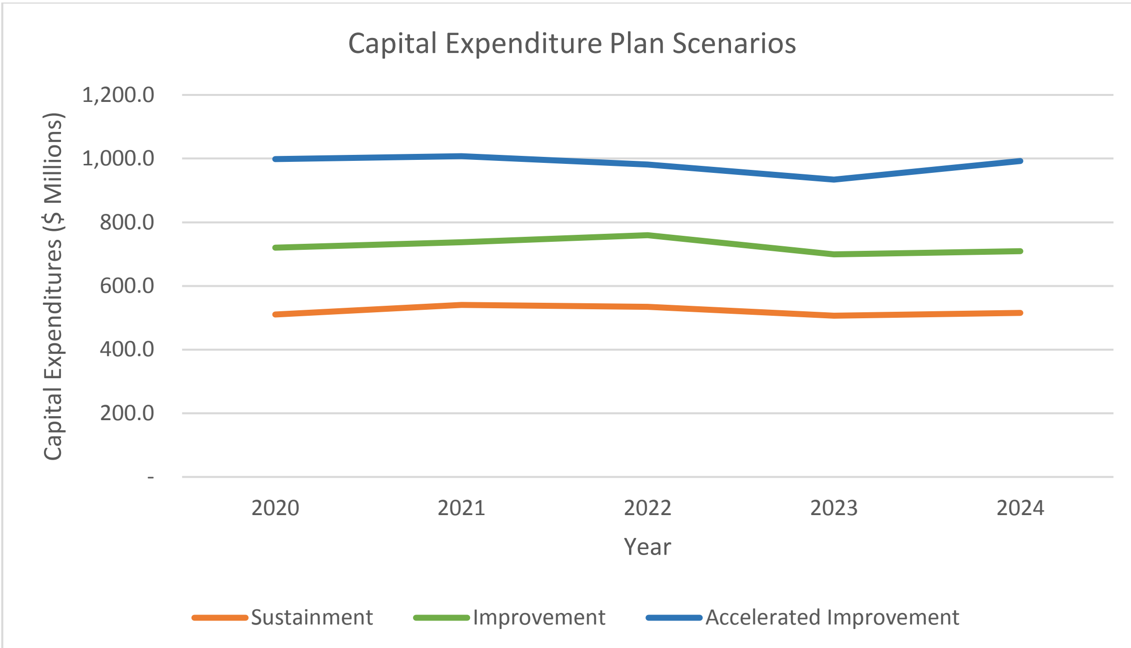


Figure 3: Preliminary High-level Capital Expenditures Scenarios

Toronto Hydro set its $562 million average annual capital budget limit to align predominantly with the "sustainment" level of investment. This level of investment best reflected the need to balance long-term system investment needs with customers' service needs and their general preference for minimizing rate increases.

E2.1.2 Focus on Operational and Financial Planning

The strategic parameters guided the operational and financial planning activities that produced the capital expenditure plan for 2020-2024. Over the course of these iterative planning activities, the utility worked to develop and optimize its program-level capital (and OM&A) expenditure plans to align with short- and long-term asset management ("AM") objectives, while remaining within the financial constraints and considerations set-out in the strategic parameters. A key feature of this planning stage was the formal integration of the utility's customer-focused Outcomes Framework. This helped to ensure that the organization's bottom-up expenditure plan proposals were directly informed by Customer Engagement results and were consistently translated into outcomes that matter to customers.

The utility developed initial capital program expenditure proposals with the aim of fulfilling strategic AM objectives. From this starting point, an iterative process generated multiple versions of the capital expenditure plan, eventually producing a penultimate plan that formed the basis of Phase 2 of Customer Engagement. The differences between the initial version of the plan – which on an aggregate basis was higher than the $562 million limit on average annual capital expenditures – and the penultimate version of the plan were as follows:

- **System Access:** Toronto Hydro reduced System Access proposals for the 2020-2024 period by approximately $65 million, primarily reflecting revisions and refinements to forecasted demand in the Customer Connections and Externally Initiated Plan Relocations programs.
- **System Renewal:** Toronto Hydro reduced System Renewal proposals for the 2020-2024 period by approximately $325 million. This was the largest curtailment of proposed investment by category, resulting from the utility seeking to strike a balance between long-term system stewardship needs and both (i) near-term customer preferences for price mitigation; and (ii) competing investment needs and priorities. Ultimately, Toronto Hydro managed to constrain the planned pacing of renewal investment to a minimum level where it expects current levels of system average reliability can be maintained, while preventing asset failure and obsolescence risk from reaching unsustainable levels over the 2020-2024 period, and making targeted improvements in critical performance areas such as PCB oil spill risks and worst performing feeders. A description of how the utility leveraged its asset management processes to appropriately pace and prioritize its System Renewal plan is provided in Section E2.2 below.
- **System Service:** Toronto Hydro reduced System Service expenditures by approximately $20 million over the 2020-2024 period. This largely reflected reductions in the scope of work and pacing of system enhancement programs (e.g. SCADA-switch installation in the Horseshoe area of Toronto) to better align with low-volume customer preferences for maintaining current average reliability performance and the need to prioritize the mitigation of failure risk through core renewal work.
- **General Plant:** General Plant expenditures increased slightly, which was the net result of increases and decreases at the program level related to scope and cost estimate refinements that naturally occur during the planning process.

Overall, the utility's result was an approximate $550 million[4] per year capital expenditure plan for 2020-2024, deferring approximately $75 million per year in forecast average capital expenditures

[4] This figure includes inflation and other allocations, and excludes Renewable Enabling Improvement ("REI") expenditures funded through provincial rate relief.

from the initial proposals for the period. This penultimate plan was subsequently refined and finalized as described in the following section.

E2.1.3 Refinement and Finalization of the Capital Expenditure Plan

Toronto Hydro took its penultimate plan back to customers for feedback on how effective the utility was in interpreting the Phase 1 Customer Engagement results and using them to inform the proposed plan. Overall, a majority of customers expressed support for either the proposed plan or doing more. A plurality of customers supported proceeding with the plan as proposed, and a minority of respondents indicated that the utility should do more or less respectively. A full analysis of the Phase 1 and Phase 2 Customer Engagement results is provided in Section E2.3 below.

In an effort to gain additional insight into the more nuanced preferences of customers, this second phase of Customer Engagement provided customers with an opportunity to give feedback on programs where Toronto Hydro assessed that it could adjust pacing to deliver greater benefits. As discussed in E2.3.2.2, customers were particularly supportive of two programs related to preventing network vault floods and fires, and the utility took this feedback into account as it made its final refinements and adjustments to the plan. The adjustments that Toronto Hydro made to programs between the penultimate plan and the final plan were as follows:

- **System Access:** Toronto Hydro further reduced System Access expenditures by approximately $50 million over the 2020-2024 period. This was the result of further demand forecasting refinements and a decision to compress the utility's meter replacement schedule and delay its commencement. The metering decision lowered the amount of spending required in the 2020-2024 period, which allowed the utility to accommodate increases to network system investments supported by customers in the second phase of Customer Engagement.
- **System Renewal:** Toronto Hydro increased System Renewal expenditures by approximately $70 million over the 2020-2024 period. This was the result of a number of refinements to program cost requirements, including an updated assessment of execution capabilities for stations work, resulting in the conclusion that the utility could support a greater pace of stations renewal to deal with a critical backlog of stations asset risk, and updated reactive capital projections based on 2017 actuals. Toronto Hydro also increased the pacing of its Network Unit Renewal work in response to support from customers in the second phase of Customer Engagement.

- **System Service:** Toronto Hydro further reduced System Service expenditures by approximately $90 million over the 2020-2024 period, reflecting further reductions in the scope and pace of System Enhancements work, as well as a reduction in the forecast needs for Stations Expansion investments. Reductions in this category were partially offset by an increase in pacing in the Network Condition Monitoring and Control program, which received support from customers in Phase 2 of Customer Engagement (see Section E2.2 below).
- **General Plant:** General Plant expenditures increased by approximately $20 million, which was the result of cost estimate refinement and forecast revisions.

In the result, Toronto Hydro produced an optimized and customer-aligned capital expenditure plan with an average investment of $562 million[5] per year over the 2020-2024 period. The final plan produced an average annual bill impact (base rates, without riders) for residential customers of 3.0 percent for distribution, below the limit set in the strategic parameters and communicated to customers in the second phase of Customer Engagement.

Section E2.2, below, provides an overview of how Toronto Hydro derived the plan from the asset management processes described in Section D of the DSP. Section E2.3 describes the results of the Customer Engagement process and how they informed the DSP.

[5] This figure includes inflation and other allocations, and excludes Renewable Enabling Improvement (“REI”) expenditures funded through provincial rate relief.

E2.2 Asset Management in Capital Planning

Toronto Hydro derived its 2020-2024 Capital Expenditure Plan from the Asset Management ("AM") Process described in Section D. As discussed in Sections D1 and D3, the utility develops its system investment programs through the annual Investment Planning and Portfolio Reporting ("IPPR") process. This process leverages the various asset lifecycle optimization and risk management methodologies discussed in Section D3 to produce capital programs and expenditure plans that are optimized to support the utility's customer-focused outcome objectives. The scenarios and recommendations developed in IPPR become inputs to business planning (discussed in the previous section), where program expenditure plan proposals are further refined, leveraging the same AM Process tools and outputs. (General Plant program proposals are developed via other operational planning activities that are also part of business planning.)

Figure 4 below (originally presented in Section D3.4) is a simplified view of the major program planning elements within the IPPR process. It depicts the cyclical nature of program development and the integration points with customer engagement.

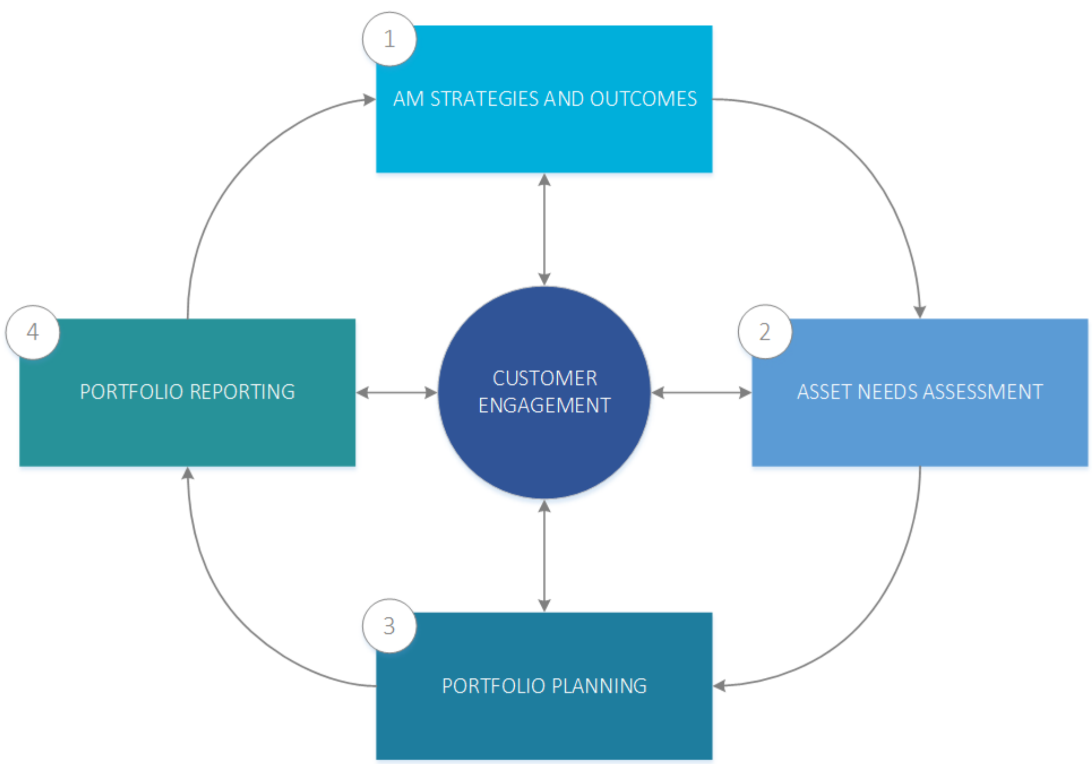


Figure 4: The IPPR Program Development Framework

The following sections explain how each of the elements in this process contributed to the production of the 2020-2024 Capital Expenditure Plan for system-related investments.

E2.2.1 Asset Management Strategies and Outcomes for 2020-2024

As summarized in Section D1, Toronto Hydro integrated its customer-focused Outcomes Framework into planning for 2017 and refined the strategic parameters into specific outcome objectives for the 2020-2024 period as summarized in the table below.

Table 1: Asset Management Outcomes Objectives

Outcome	Objectives
Customer Service	• Continue connecting customers of all types (including distributed energy resources) on time and cost-effectively, without harming system performance for existing customers. • Comply with customer service regulations and standards over the 2020-2024 period.
Reliability & Safety	• Maintain and, where appropriate, reduce asset failure risk – as represented by leading indicators like asset condition – over the 2020-2024 period, supporting stable system reliability and safety outcomes for current and future customers. • Maintain system reliability at current levels over the 2020-2024 period while (1) improving the experience for customers with poor reliability and power quality, and (2) improving the resiliency of the distribution system. • Continue to reduce and eliminate public and employee safety risks, for example by removing higher-risk legacy assets from the system within a specific and reasonable timeframe. • Strive for zero public and employee safety incidents over the 2020-2024 period. • Comply with all safety regulations and standards over the 2020-2024 period.
Public Policy	• Respond effectively to public policy during the 2020-2024 period, including by enabling the timely connection of all forecasted renewable generation projects and implementing a Conservation First approach where appropriate.
Environment	• Endeavour to eliminate the risk of PCB-contaminated oil spills by 2025. • Reduce the system’s impact on the environment caused by greenhouse gas emissions and oil leaks of all types. • Comply with all environmental regulations and standards over the 2020-2024 period.
Financial	• Minimize average rate increases over the 2020-2024 period while continuously improving the value delivered to current and future customers.

Once these outcome objectives were established, Toronto Hydro began the process of selecting performance measures and program-level objectives to track and assess the utility's achievement of these outcomes for the 2020-2024 period. This process continued as the program expenditure plan proposals were developed, and throughout the refinement and finalization of those plans. It resulted in the final suite of Customer Performance Scorecard discussed in Section C of the DSP and the program-specific outcome objectives that can be found in the "Outcomes and Measures" section of each capital program in Sections E5 to E8.

E2.2.2 Asset Needs Assessment for 2020-2024

Concurrent with the development of the utility's asset management outcome objectives, summarized in Table 1 above, Toronto Hydro performed an Asset Needs Assessment to develop a baseline understanding of the current state of its distribution system. As explained in Section D3, the Asset Needs Assessment includes a Current State Assessment ("CSA") and a System Needs and Challenges Review. The results of these analyses informed the capital budget limit that Toronto Hydro set in the strategic parameters for the business plan.

E2.2.2.1 CSA Results

The CSA produced foundational information, including asset demographics (i.e. counts, age and nameplate attributes) and condition demographics. These data points informed program pacing and prioritization decisions throughout business planning.

1. Assets Past Useful Life

As discussed in Section D3.2, to assess the age demographics of its distribution system, Toronto Hydro examines the proportion of assets across the system that are operating at or beyond useful life (the Assets Past Useful Life metric, or APUL). The age demographics of the system as of the beginning of 2018 are summarized in Figure 5 below.

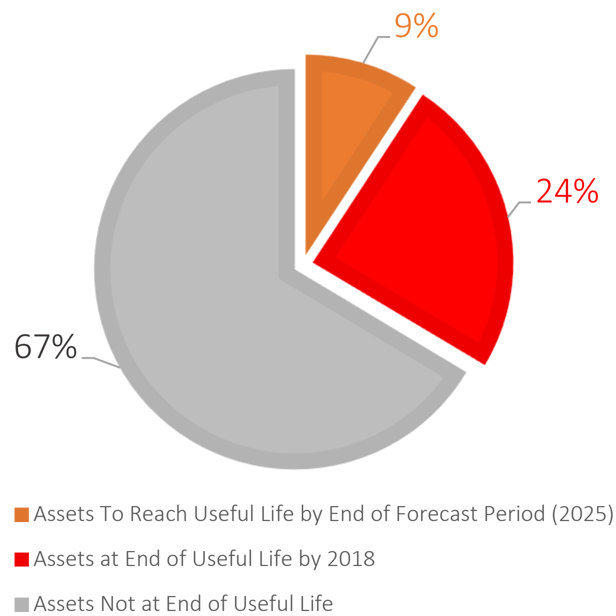


Figure 5: Percentage of Assets Past Useful Life

In 2015, Toronto Hydro's percentage of assets past useful life was 26 percent, with an additional 7 percent forecasted to reach expected useful life by 2020. As a result of Toronto Hydro's ongoing renewal efforts, the APUL measure is no longer deteriorating as it did during Toronto Hydro's previous 2011-2014 rate period. However, approximately a quarter of the utility's asset base continues to be operating beyond its expected useful life, and an estimated additional 9 percent will reach that point by 2025, indicating that a significant proactive renewal program remains necessary to prevent the APUL backlog from increasing. An increase in the APUL backlog would not only amount to a deterioration in these recent improvements, but also a corresponding deterioration in reliability, safety risk, reactive replacement costs, and other outcomes driven by asset failure.

2. Asset Condition Demographics

The utility also examined the current state of its asset condition demographics to determine which asset classes were showing the greatest signs of deterioration, and took this into account in establishing planning scenarios. Among the subset of asset classes that are analyzed using inspection information and Toronto Hydro's Asset Condition Assessment ("ACA") model, major civil assets – including poles, cable chambers, and network vaults – and major stations electrical assets – including circuit breakers and power transformers – are showing the greatest signs of material deterioration.

Civil assets are the backbone of the distribution system and must be adequately maintained to ensure public and employee safety and the long-term viability of the distribution system. Stations assets are the highest criticality assets on the system and require long lead times for replacement. As a result, these assets must be addressed proactively to mitigate the risk of catastrophic failure, high-impact and long-duration outages, and other contingency scenarios. Toronto Hydro considered various sustainment and improvement strategies for these asset classes in developing its planning scenarios in IPPR.

Toronto Hydro set-out to develop a plan that would invest the minimum necessary to prevent these age and condition-related risks from worsening over the 2020-2024 period and beyond. This was a key consideration in the utility's selection of its capital budget limit for business planning. The Portfolio Planning section below (E2.2.3) provides additional details on how asset condition informed the pacing of investment in Toronto Hydro 2020-2024 Capital Expenditure Plan.

E2.2.2.2 System Needs and Challenges Review

In addition to the information generated by the CSA, Toronto Hydro considered a number of other indicators of system investment need, including system utilization, connection capacity, distributed generation forecasts, legacy asset profiles (e.g. lead cable replacement needs), regional planning considerations, and other factors. The utility developed strategic investment scenarios for each of these issues, which in turn informed the capital expenditure plan scenarios discussed in Section E2.1.

Section D2 provides an overview of the various considerations resulting from the System Needs and Challenges Review. Section E2.3.3 provides additional insight into the strategies for addressing these issues in the 2020-2024 Capital Expenditure Plan.

E2.2.2.3 System Reliability Performance and Projection Scenarios

System reliability is an important customer-focused outcome and a lagging indicator of performance, including the effectiveness of the subset of System Renewal and System Service investments that are primarily directed toward preventing outages and shortening outage duration (e.g. direct-buried cable replacement). Toronto Hydro's renewal and modernization efforts over the last decade have paused the overall deterioration in reliability performance that began in the mid-2000s. As shown in Figure 6 and 7, the frequency and duration of outages have essentially plateaued.

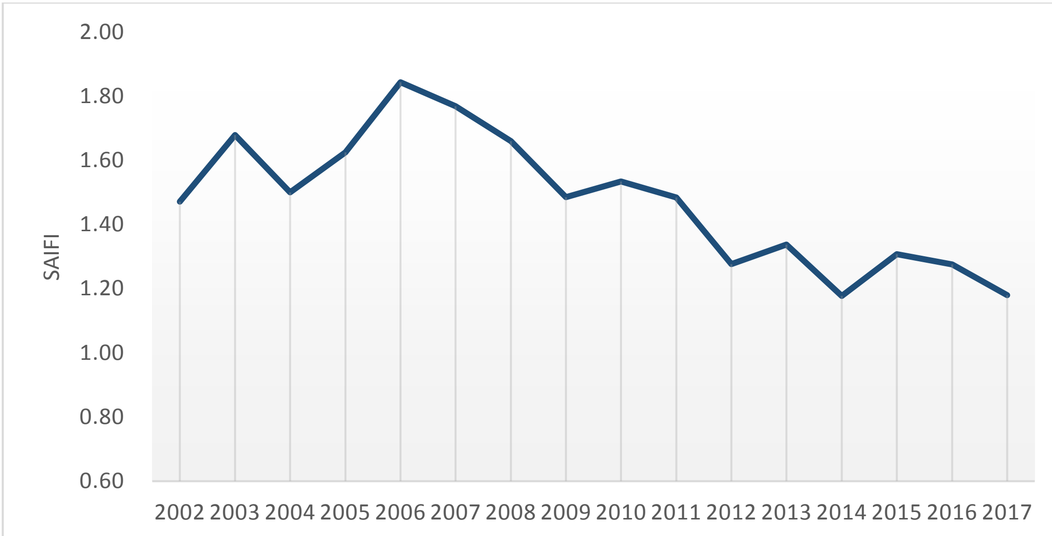


Figure 6: Historical SAIFI (Excluding MEDs and Loss of Supply)

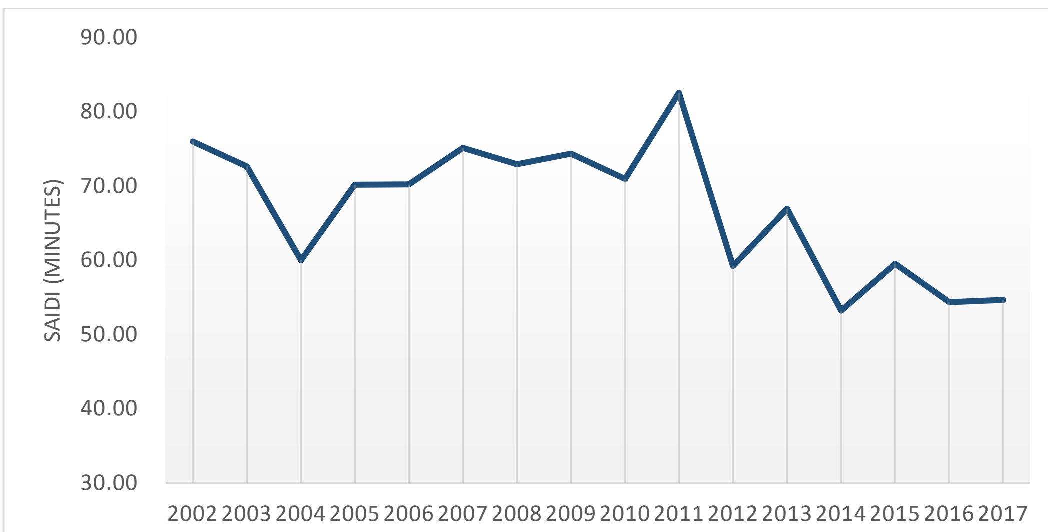


Figure 7: Historical SAIDI (Excluding MEDs and Loss of Supply)

Toronto Hydro has seen improvements in the frequency and duration of outages caused by defective equipment. However, defective equipment continues to be by far the largest contributor to SAIFI, at 36 percent, and SAIDI, at 44 percent. In light of the age, condition, and legacy asset related risks discussed above, Toronto Hydro concluded that a shift to a more reactive renewal approach would – in addition to being a more costly approach to renewal over the long-term – result in a decline in reliability over the near- and long-terms, with potentially significant impacts for customers in areas served by legacy assets such as direct-buried cable and rear-lot plant. Furthermore, as discussed in detail in Section D2, Toronto Hydro anticipates that increasingly frequent adverse and extreme weather events will put additional reliability pressures on the system, making the resiliency of the system and the utility's operations a greater concern over the medium- to long-term than in past planning cycles.

As illustrated in Figure 2 in Section E2.1, Toronto Hydro developed preliminary "sustainment," "improvement," and "accelerated improvement" expenditure plan scenarios for each system investment program and used these to define the lower and upper bounds of potential capital budgets for the planning period.[6] In the manner described in Section D3.4, Toronto Hydro used the asset demographic information produced by the CSA analysis to run each of the scenarios through its reliability projection methodology to assess at what overall expenditure level the utility could, at a minimum, support the sustainment of current system average reliability for outages caused by defective equipment over the 2020-2024 period. The results of this analysis are shown in Figures 8 and 9 below.

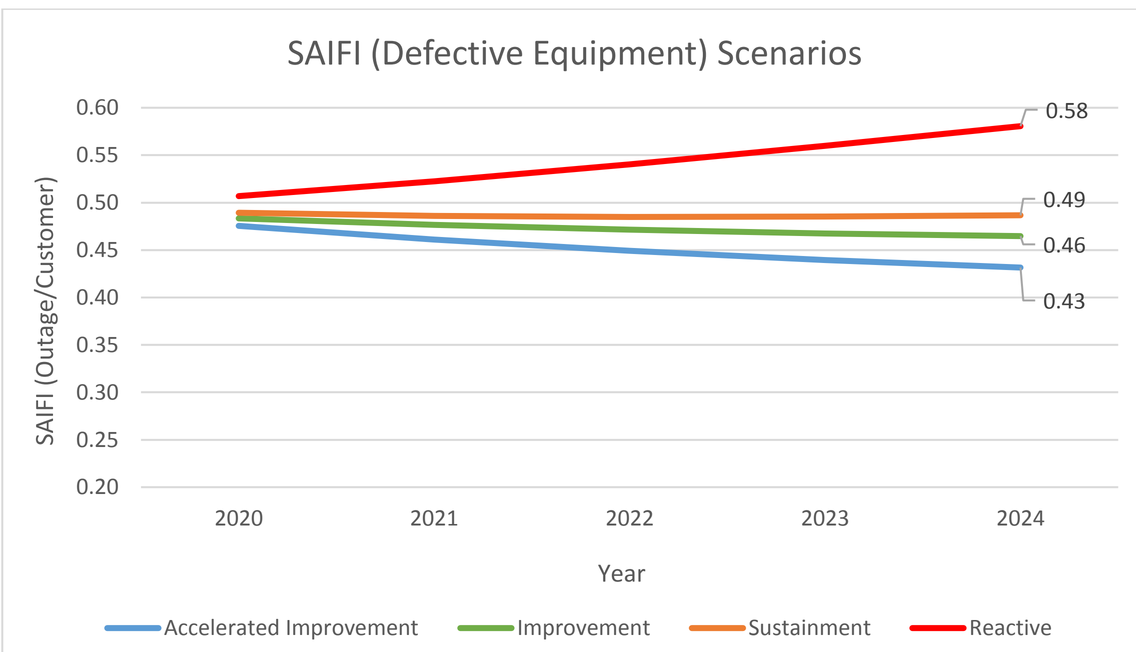


Figure 8: SAIFI Scenarios for Strategic Planning

[6] For the purpose of this analysis, Toronto Hydro assumed General Plant investments in the 2020-2024 period would be in line with historical averages.

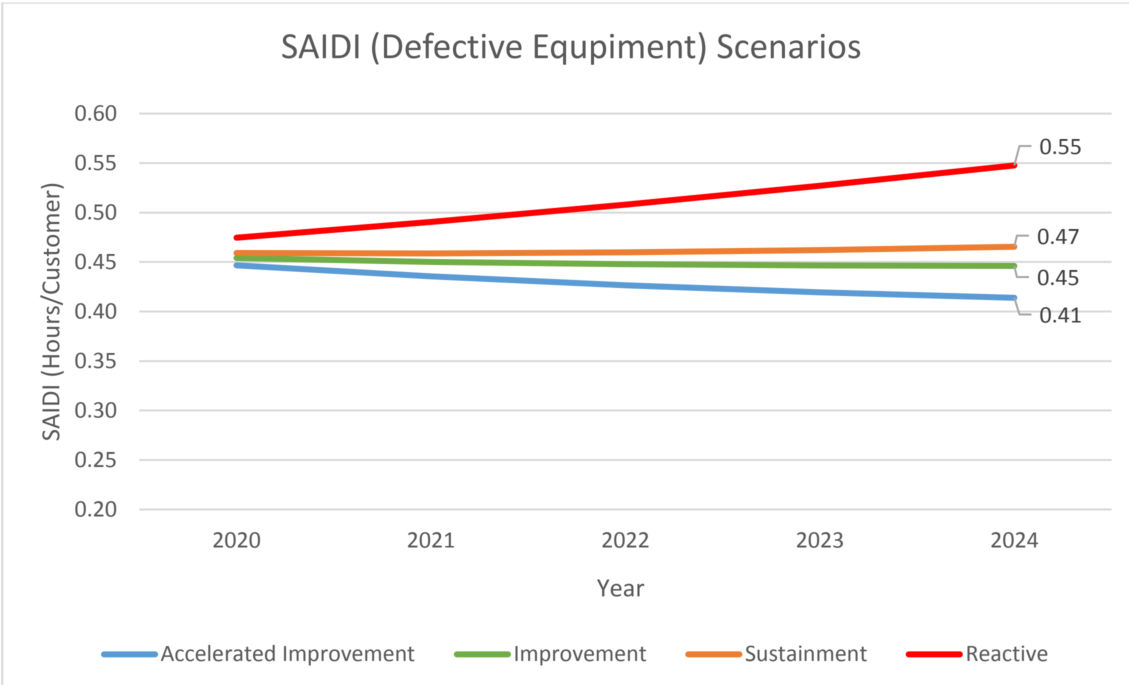


Figure 9: SAIDI Scenarios for Strategic Planning

Toronto Hydro considered the results of these projections alongside the other drivers and risk factors resulting from the CSA and System Needs and Challenges Review, as well as anticipated inflation and cost escalation for the forecast period, and determined that a capital expenditure plan of up to $562 million per year would be necessary to support sustainment of current system reliability while allowing the utility to deliver on the other asset management outcome objectives listed in Section 2.2.1 above. Through refinement, and with consideration for results from Phase 2 of Customer Engagement, the utility produced an optimized plan within this limit. The following section provides a detailed discussion of how this plan was optimized to support Toronto Hydro's customer-focused asset management objectives at the individual program level.

E2.2.3 Portfolio Planning for 2020-2024

Toronto Hydro's Portfolio Planning process used the outputs of the Asset Needs Assessment to develop program-level expenditure plan proposals that would support the utility's asset management outcome objectives for 2020-2024.

As described in Section D3.4.3, Toronto Hydro developed bottom-up expenditure plan scenarios for each capital program, leveraging the asset lifecycle optimization and risk management practices and methodologies described in Section D3. The proposals were evaluated in relation to their potential contribution to: (i) the utility's asset management outcome objectives and measures; and (ii) alignment with customer needs and preferences. The program proposals were further refined as a result of business inputs and information, as well as feedback received in the second phase of Customer Engagement (discussed in Section E2.3 below).

The following subsections describe how the outputs of the Asset Needs Assessment and the utility's asset lifecycle optimization and risk management practices informed the timing and pacing of the programs in the 2020-2024 Capital Expenditure Plan.

E2.2.3.1 System Access Program Expenditures

Toronto Hydro developed a 2020-2024 System Access expenditure plan that is responsive to the utility's need to continuously meet its legally mandated service obligations, including the requirement to safely connect load and generation customers in a timely manner, and requirements to comply with revenue metering and billing standards. The pacing of investments in this category was largely dictated by the projected demand in these areas over the 2020-2024 period. Customer Service delivery and responsiveness to Public Policy are the primary outcomes supported by these investments.

Table 2: 2020-2024 System Access Expenditure Plan ($ Millions)

Programs	2020	2021	2022	2023	2024
Customer Connections	42.9	43.9	44.8	45.6	46.3
Externally Initiated Plant Relocations & Expansions	11.4	20.8	4.6	4.7	4.5
Generation Protection, Monitoring, and Control	3.7	2.3	2.4	2.5	2.7
Load Demand	11.3	11.4	18.5	22.6	23.6
Metering	22.6	14.8	23.6	30.6	39.2
System Access Total	**91.8**	**93.3**	**93.9**	**106.0**	**116.4**

1. Connecting Load Customers

Toronto Hydro's Customer Connections (E5.1) and Load Demand (E5.3) programs support the safe, timely, and cost-efficient connection of load customers. Forecast expenditures for load connections were based on historical trends in gross cost and customer contribution amounts for load connection activities. They were also informed by development trends in the City. The utility's 2020-2024 expenditure plan anticipates growth in new services, upgrades, and removals based on current and proposed development. (Refer to Section E5.1 for more details.)

The Load Demand program addresses near-term system capacity constraints in areas of concentrated load growth. Toronto Hydro's Distribution Capacity and Capability Assessments (summarized in Section D3.3) identified a number of areas in both the Horseshoe and downtown regions of the system where investments such as load transfers, cable upgrades, and equipment upgrades will likely be required to ensure the utility can continue to connect customers efficiently. These investments are also necessary to maintain sufficient grid flexibility to handle contingency scenarios and optimize planned work schedules, contributing to Toronto Hydro's reliability objectives and improving customer satisfaction by providing large customers with greater scheduling flexibility for planned outages.

Toronto Hydro's 2015-2017 Load Demand investments have been successful in reducing constraints. The utility has (i) alleviated 10 highly loaded buses; (ii) reduced the number of highly loaded feeders by 25; and (iii) reduced the number of feeders subject to switching restrictions during the summer months by 28. As discussed in Section C2.3.3, Toronto Hydro's capacity investment strategies during the 2020-2024 period were developed to prevent system capacity (as indicated by the utility's proposed System Capacity measure) from deteriorating in the face of forecasted development and demand.

Overall, the proposed expenditure plans in these two load-driven System Access programs reflect the investments required to connect customers in accordance with the OEB's service connection targets, while maintaining system performance for existing customers and improving the effects of scheduled outages on the operations of larger customers.

2. Connecting Generation Customers

Toronto Hydro's Customer Connections (E5.1) and Generation Protection, Monitoring, and Control (E5.5) programs support the safe, timely, and cost-efficient connection of distributed generation ("DG") customers to the grid, including renewable energy generation ("REG") projects. The utility aligned the planned 2020-2024 expenditures in both programs with its 2018-2024 generation connection forecasts, illustrated in Figures 2 through 7 in Section E3, and summarized in Figure 10 below. These forecasts took into account historical connection trends, completed assessments, and anticipated projects with respect to various DG programs.

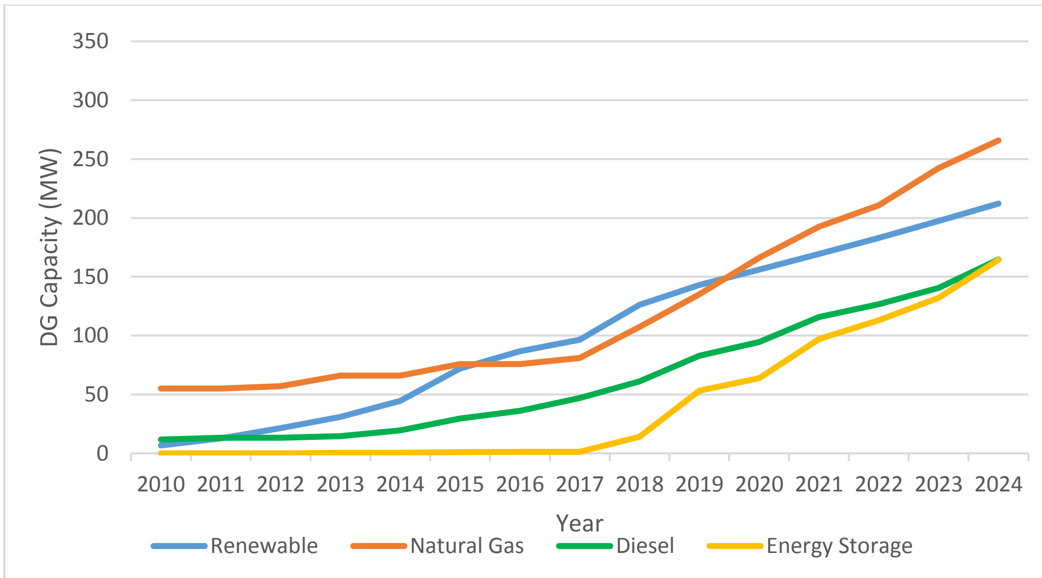


Figure 10: Forecast Generation Capacity

Toronto Hydro's Generation Capacity and Capability Assessment (described in Section E3.3) identified a number of challenges to connecting the forecasted 581 MW of incremental DG anticipated by 2024, including short-circuit capacity constraints (illustrated in Figure 11 below), islanding risks, and system thermal limits.

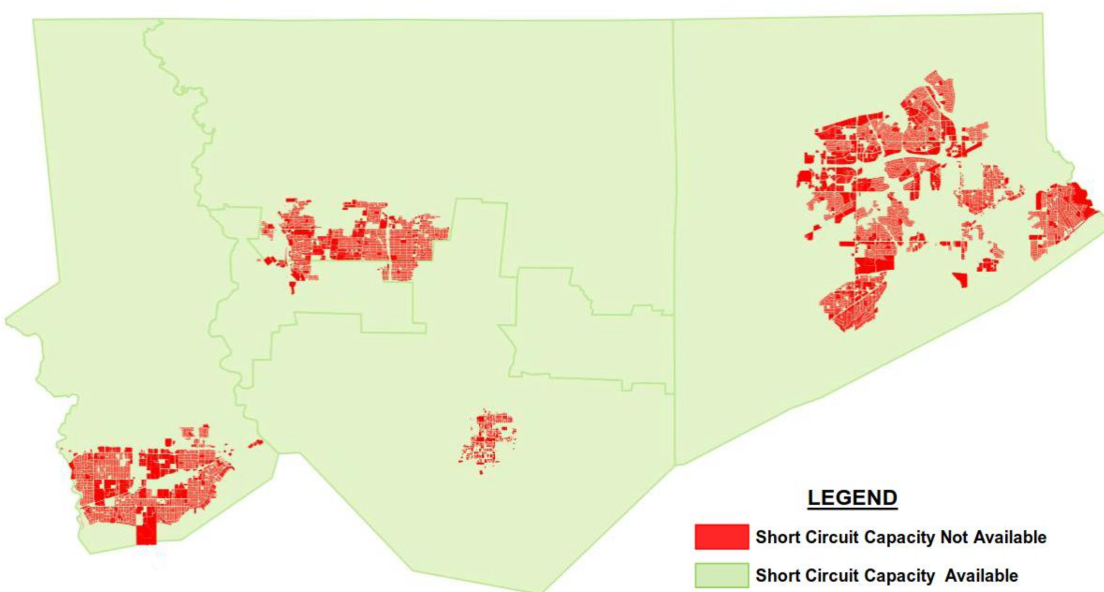


Figure 11: Distribution System Short Circuit Capacity Constraints Map

Connecting all REG projects in accordance with the OEB's generation connections standards continues to be a key Public Policy outcome objective for Toronto Hydro. To support this outcome, the utility developed a plan for the 2020-2024 Generation Protection, Monitoring, and Control program that will make targeted investments in bus-tie reactors and monitoring and control equipment, allowing the utility to address the challenges noted above and continue to connect all forecasted DG. The Energy Storage Systems program (System Service) also includes investments to support the mitigation of DG islanding risk.

3. Accommodating Third-Party Plant Relocation Requests

The Externally Initiated Plan Relocations and Expansions program (E5.2) funds plant relocations and expansions triggered by third-party requests. Toronto Hydro is obligated by the *Public Service Works on Highways Act*[7] ("PSWHA") and section 3.4 of the Distribution System Code ("DSC") to accommodate these requests in a fair and reasonable manner. The timing and scope of work in this program is difficult to predict and largely out of Toronto Hydro's control. For the 2020-2024 period, the utility developed an expenditure plan to address committed relocation and expansion projects by Metrolinx, the TTC, and the City of Toronto. In light of the volatility of this program, the utility proposes to continue the Variance Account for Externally Driven Capital for the 2020-2024 period (Exhibit 9, Tab 1, Schedule 1).

4. Metering Investments

Investments in the Metering program (E5.4) are largely driven by the need to remain in compliance with OEB minimum standards for billing accuracy and Measurement Canada and IESO requirements related to metering and billing. Based on a needs assessment for its metering assets, Toronto Hydro developed a plan for 2020-2024 that is largely driven by the timing of metering and metering system upgrade cycles. Forecast expenditures related to Wholesale Metering Compliance, Suite Metering, Large Customer Interval Metering and System Upgrades are generally in line with, or lower than, 2015-2019 expenditures in these categories.

The primary driver of greater planned expenditures in the outer years of the 2020-2024 period was a necessary ramp-up in the utility's Residential and Small C&I Meter Replacement activities to address end-of-life meters with expiring seals. Toronto Hydro cannot, as a matter of law, bill customers using meters with expired seals. The bulk of these meters will have their seals expire in

[7] R.S.O. 1990, c. P-49.

2024, and, beginning in 2021, they will surpass their expected 15 year lifespan, increasing the probability of failure beyond standard operating levels. Without intervention, 90 percent of these meters will be operating beyond useful life as of 2025. The option of resealing these meters and allowing them to run beyond their expected lifespan was considered, but the risks to billing accuracy, customer satisfaction, and financial stability were deemed too high. Therefore, Toronto Hydro has developed a plan to replace these meters in a staged manner beginning in 2022.

In addition to complying with all customer service and billing regulations for Metering assets, investments in the next-generation metering technology will enhance Customer Service, Reliability and Financial efficiency outcomes to the benefit of current and future customers. For example, the installation of next-generation residential and small C&I meters with "last gasp" functionality will allow Toronto Hydro to pursue customer-specific reliability measures system-wide, while the continued installation of "ION" meters for large users will help Toronto Hydro better diagnose and respond to power quality issues.

5. Grid Modernization in System Access

Toronto Hydro's ongoing grid modernization efforts are supported by Metering and DG-related investments in its 2020-2024 plan. For example, as mentioned above, next generation metering technology will provide enhanced smart grid benefits to support reliability and customers service outcomes, while the expansion of SCADA monitoring and control will allow greater DG penetration.

E2.2.3.2 System Renewal Program Expenditures

As described in detail throughout Section D2 ("Overview of Distribution Assets") and in the System Renewal programs (Section E6), continued proactive renewal expenditures are required during the 2020-2024 period to manage significant safety, reliability and environmental asset risks and to ensure stable and predictable performance for current and future customers. As noted in E2.2.2 above, approximately one quarter of Toronto Hydro's assets are operating beyond Useful Life and the system continues to age at a rate comparable to the projected rate of aging in the 2015-2019 DSP. Furthermore, condition demographic results indicate substantial asset investment needs for a number of critical asset classes, and the utility continues to face challenges related to higher-risk, obsolete legacy assets and asset configurations such as rear lot plant and direct-buried cable.

As noted in the business planning discussion in E2.1, the first phase of the Customer Engagement exercise indicated that most low-volume and medium-sized customers were satisfied with average reliability performance and would prefer Toronto Hydro maintain current performance while minimizing price increases in the near-term. Larger users indicated a greater interest in reliability and system resiliency and a willingness to pay to maintain or improve performance in these areas. In light of these results, and leveraging the asset risk assessment and mitigation practices discussed in Section D3, Toronto Hydro developed program expenditure plans for 2020-2024 that are set a the minimum pace necessary to sustain overall asset risk and reliability performance at current levels, while driving targeted outcome improvements such as reducing the risk of PCB contaminated oil spills, reducing the level of failure risk related a significant backlog of aging and poor condition stations assets, and improving performance on worst performing feeders.

Table 3: 2020-2024 System Renewal Expenditure Plan ($ Millions)

Programs	2020	2021	2022	2023	2024
Area Conversions	41.4	47.2	46.3	50.4	35.6
Network System Renewal	18.6	19.3	18.5	17.7	18.3
Reactive and Corrective Capital	61.2	62.4	63.5	64.4	65.8
Stations Renewal	27.5	35.3	29.4	27.0	22.4
Underground System Renewal - Downtown	15.1	22.5	23.9	30.0	30.6
Underground System Renewal - Horseshoe	93.0	88.7	90.3	93.1	95.2
Overhead System Renewal	49.8	50.4	51.3	56.5	57.7
System Renewal Total	**306.6**	**325.7**	**323.1**	**339.0**	**325.5**

1. Overhead Asset Renewal Investments

Failure and obsolescence risks related to overhead grid system assets are addressed by Toronto Hydro’s Overhead System Renewal (Section E6.5), Area Conversions (Section E6.1) and Reactive and Corrective Capital (Section E6.7) programs. The utility paced the 2020-2024 expenditure plan for these programs to maintain current system reliability performance, prevent age and condition related asset risk from accumulating over the period, and to continue to reduce and eliminate safety and environmental risks (and other deficiencies) associated with legacy assets and asset configurations.

As highlighted in Section D2.1.1, demographic pressures related to wood poles and pole top transformers were identified as key drivers of overhead renewal need during the 2020-2024 period. Wood poles are critical to the safety and viability of the distribution system.

Figure 12: Deterioration at the base of a pole

Toronto Hydro examined the current and projected health scores of its wood pole population to ensure the proposed pacing of wood pole replacement could prevent failure risk across this asset class from worsening over the forecast period. As shown in Figure 13 below, about a third of Toronto Hydro's are showing at least material deterioration, with approximately 11,000 poles in each of the HI4 ("material deterioration") and HI5 ("end-of-serviceable life") condition bands. The utility projects this number could nearly triple to an estimated 34,000 by 2024 without intervention, including an increase in HI5 poles from approximately 1,000 to 17,000. The Overhead System Renewal program budgets for approximately 13,000 pole replacements between 2018 and 2024. Combined with pole replacements in the Area Conversions program and the Reactive Capital program, and prioritizing poles within or nearing the HI5 category, Toronto Hydro anticipates that its 2020-2024 expenditure plan as proposed is sufficient to manage wood pole failure risk.

Wood pole replacement is the highest-volume renewal activity out of the subset of assets that are analyzed through Toronto Hydro's ACA methodology. Given the importance of managing the overall condition-informed failure risk for this asset class over the planning period, the utility is proposing to track and report on wood pole condition demographics as a Custom Performance Measure over the 2020-2024 period (see Section C for more details).

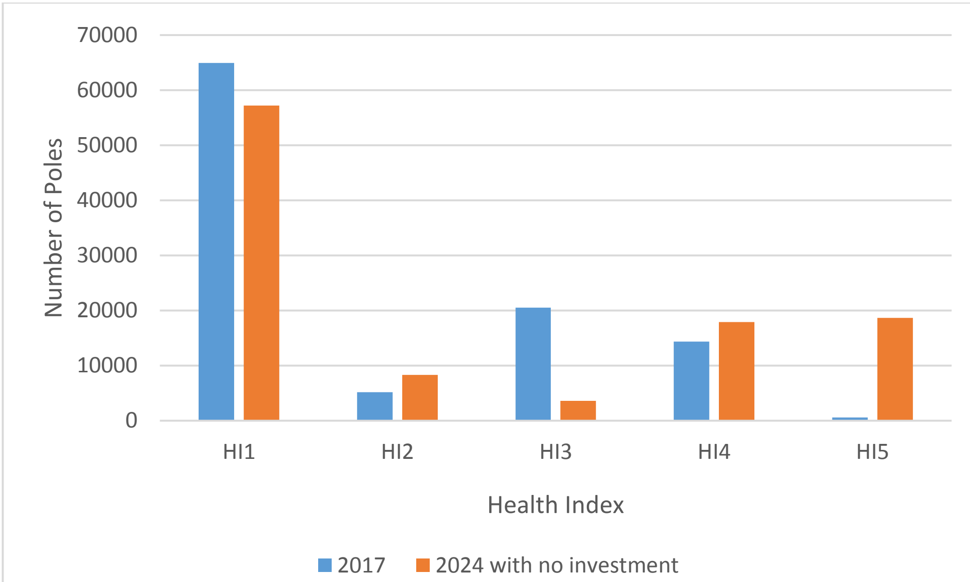


Figure 13: Health of Wood Poles as of 2017 and 2024 (without investment)

The utility also faces a significant increase in failure risk related to pole-top transformers, with the percentage of units operating beyond their 35 year useful life projected to increase from 14 percent to 40 percent by 2024. Compounding the reliability dimension of this risk is the risk of pole-top transformer failure resulting in PCB contaminated oil spills. The utility has paced pole-top transformer replacement in the aforementioned programs to align with the utility's reliability objectives and to work towards eliminating the risk of PCB contaminated oil spills.

Figure 14: Rusted Overhead Transformers at Risk of Leaking Oil

As discussed in Section D2.2.1.1, obsolete, legacy overhead construction types are an ongoing challenge for Toronto Hydro. The utility is continuing to address aging, deteriorating, and poor performing rear lot construction and box construction plant at a steady pace. These asset types carry a number of acute safety, reliability, and customer service risks that Toronto Hydro is in the process of eliminating.

Figure 15: Box Construction (left). Replacing a transformer on a poor condition Rear Lot pole (right)

As detailed in the Area Conversions program (Section E6.1), because of the continuing decline in rear lot plant performance, and the high complexity and duration of rear lot conversion projects, Toronto Hydro determined it is necessary to continue removing rear lot plant proactively at a pace that is consistent with 2015-2019 accomplishments, prioritizing areas where customers are experiencing the worst performance. The long-term pacing strategy for rear lot plant is represented in Figure 16 below.

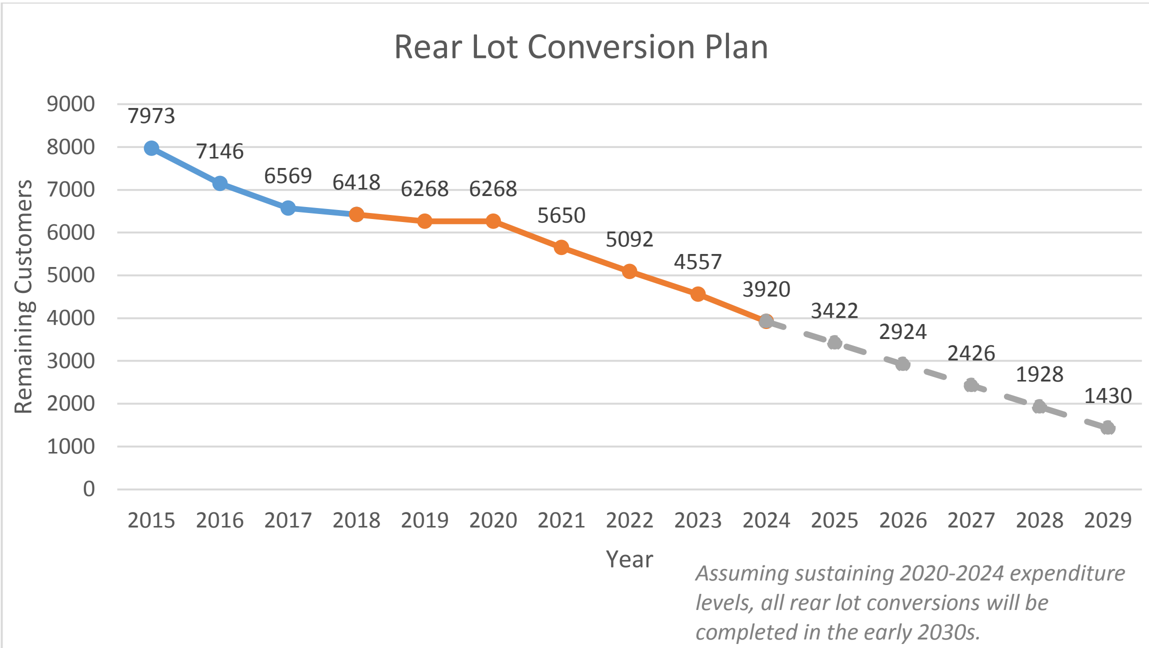


Figure 16: Rear Lot Conversion Plan

Box construction is also addressed in the Area Conversions program. Toronto Hydro developed a plan for 2020-2024 that continues the strategy of eliminating all box construction poles by 2026, as first articulated in the 2015-2019 DSP. This is the fastest executable rate at which the utility can eliminate this legacy configuration. The utility's pacing strategy for this type of equipment is driven primarily by a need to eliminate the various safety risks that these assets present to employees and the public. (For more information, please reference to Section E6.1.) Figure 17 illustrates the plan to eliminate box construction. Toronto Hydro plans to report its progress on this plan as a 2020-2024 Custom Performance Measure under the Safety outcome category (see Section C2.2).

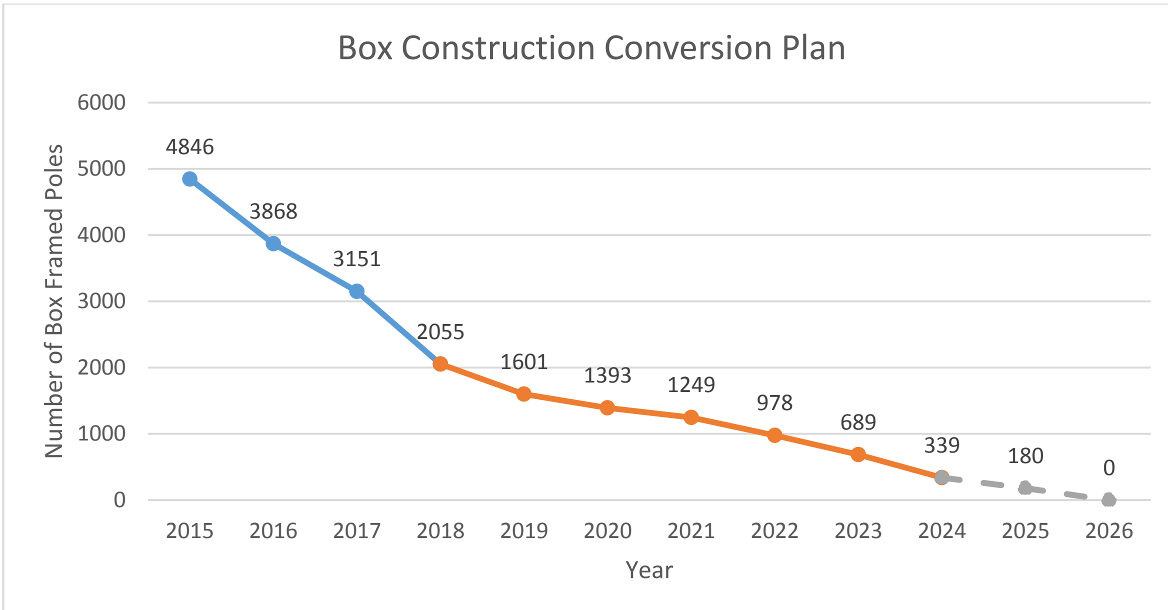


Figure 17: Box Construction Conversion Plan

2. Underground Asset Renewal Investments

Failure and obsolescence risks related to underground system assets are addressed by Toronto Hydro's Underground System Renewal - Horseshoe (Section E6.2), Underground System Renewal - Downtown (Section E6.3), Area Conversions (Section E6.1), and Reactive and Corrective Capital (Section E6.7) programs. The utility paced the 2020-2024 expenditure plans for these programs to maintain current system reliability performance, prevent age, condition and obsolescence related asset risk from accumulating over the period, and to continue to reduce and eliminate safety and environmental risks (and other deficiencies) associated with legacy assets and asset configurations.

Legacy asset performance and risks – particularly the reliability-related failure risks associated with obsolete cables – continue to be the most significant driver of renewal needs on the underground system. Underground cables have been the single greatest contributor to outages caused by defective equipment, resulting on average in 140,000 customer hours of interruption annually. In the Horseshoe area of Toronto, direct-buried cable, and direct-buried cable in duct continues to fail, often in clusters, as it nears and exceeds its expected useful life, resulting in potentially significant reliability impacts and pressure on Toronto Hydro's worst performing feeder measures (e.g. "FESI-7").

The utility's Asset Needs Assessment identified over 800 circuit-kilometres of direct-buried cable and direct-buried cable in duct remaining in the Horseshoe area as of 2018. Of this, approximately 370 circuit-kilometres are of the highest-risk cross-linked polyethylene ("XLPE") type. Approximately 70 percent of this cable is currently beyond its useful life and the utility anticipates that 90 percent will be at or beyond useful life by 2024. To prevent reliability from degrading, the utility developed a plan to proactively replace approximately one quarter of the 800 circuit-kilometres (i.e. an estimated 215 circuit-kilometres) of this cable in the Underground System Renewal – Horseshoe program during the 2020-2024 period, prioritizing the highest-risk neighbourhoods based on cable age, performance, criticality, and adjacency to other assets at risk of failure. Figure 18 below shows Toronto Hydro's long-term direct-buried cable replacement plan. Given its significant impact on reliability and the fact that this is the utility's largest renewal activity, Toronto Hydro plans to report its progress on this plan as a 2020-2024 Custom Performance Measure under the Reliability outcome category (see Section C).

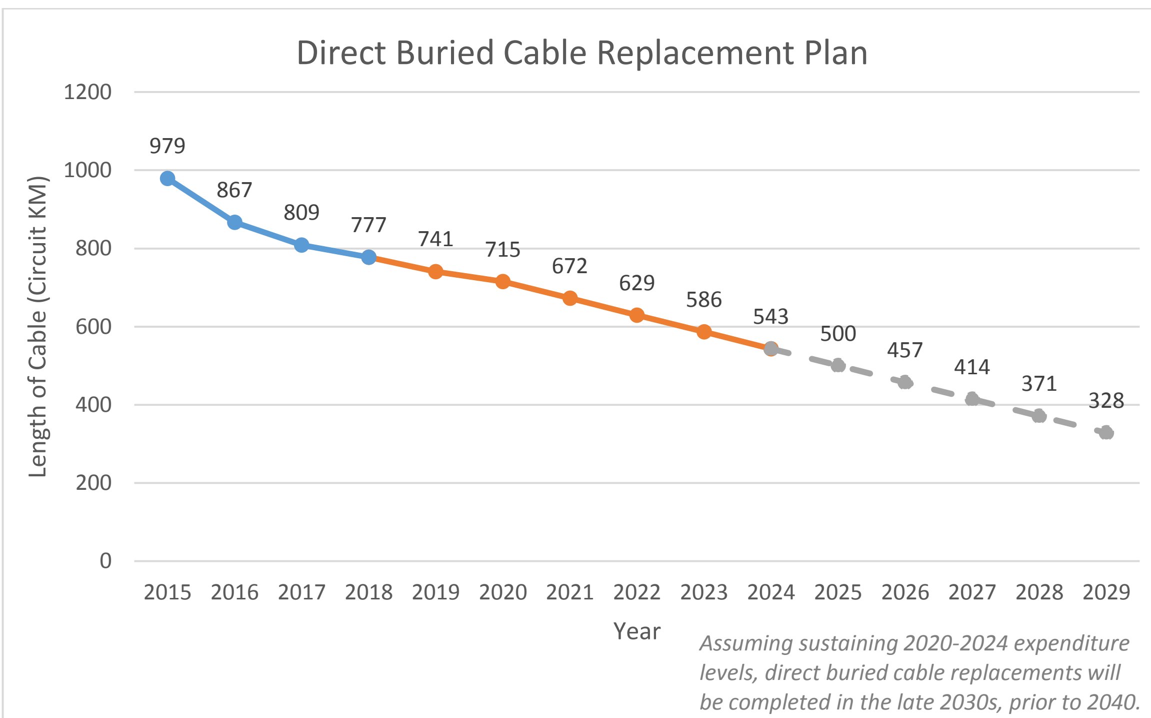


Figure 18: Direct Buried Cable Replacement Plan

Toronto Hydro's Asset Needs Assessment also resulted in the introduction of a long-term renewal strategy for lead cable in the downtown area. Due to the generally good reliability performance of lead-covered cable, Toronto Hydro has historically managed these assets through reactive and corrective interventions and targeted repairs. However, these cable types have shown signs of aging and declining performance in recent years and are largely considered obsolete in North America due to various safety and environmental risks (see Section E6.3 for more details). There is only one supplier of paper-insulated lead-covered ("PILC") cable remaining in North America and no suppliers of asbestos-insulated lead-covered ("AILC") cable.

Figure 19: Collapsed cable splice

To manage the significant magnitude of this asset renewal need, Toronto Hydro developed a predictive performance model to prioritize the cable segments on the system, using factors such as historical failures, number of splices, age and customer base. The results of this analysis are summarized in Section E6.3, Figures 1 and 2. Based on this prioritization model, Toronto Hydro developed a plan to maintain reliability performance for affected customers by replacing approximately 2 percent of the 1,100 kilometres of PILC cable and 20 percent of the 220 kilometres of AILC cable with modern polymeric cables in the 2020-2024 period. The long-term replacement plans for AILC and PILC cable are represented in Figures 20 and 21 below.

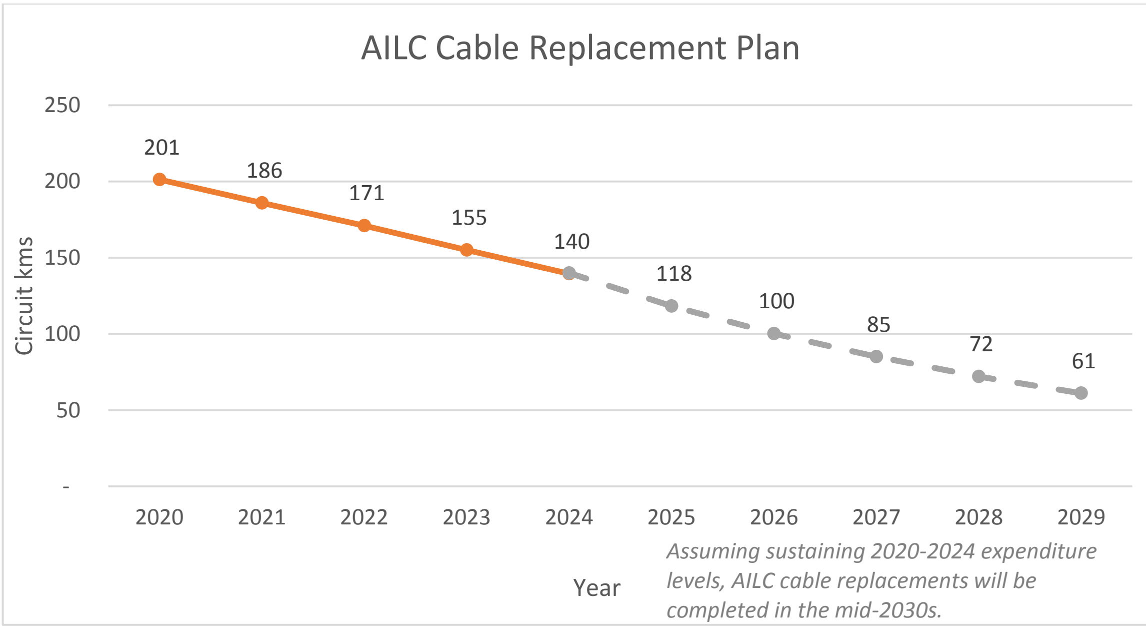


Figure 20: AILC Replacement Plan

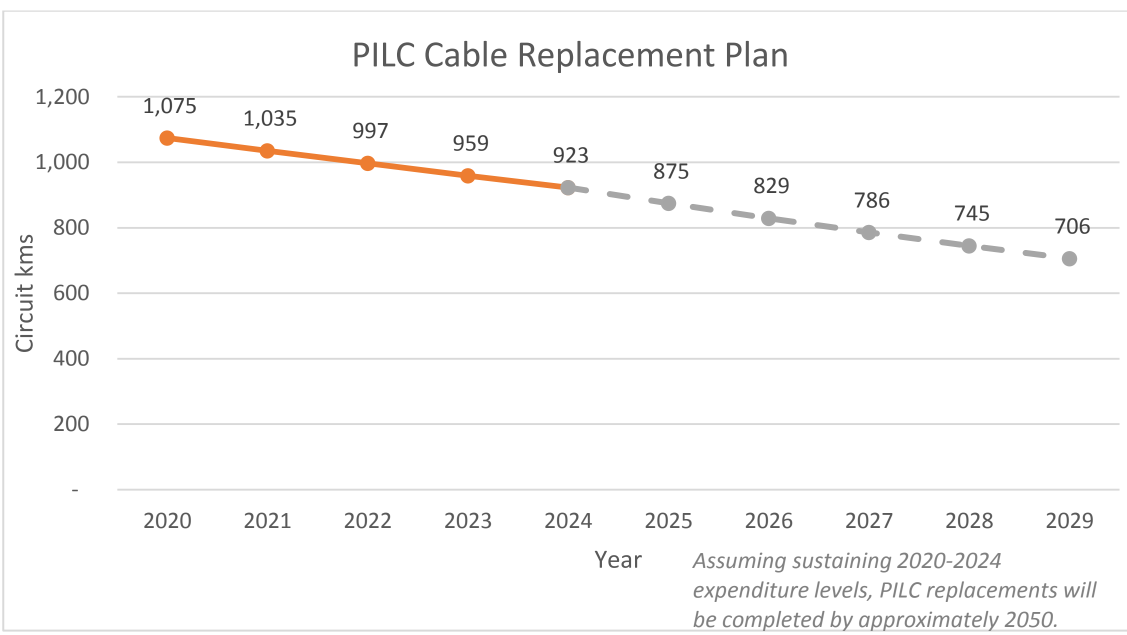


Figure 21: PILC Cable Replacement Plan

Other electrical assets addressed by the Underground System Renewal programs include transformers and switches in the Horseshoe area and on the Underground Residential Distribution ("URD") system, which serves low-volume customers in parts of the downtown area. These assets will be prioritized based on age, condition and historical performance and will largely be addressed in conjunction with underground cable rebuild projects, except on the URD system and in cases where submersible, pad-mount and vault transformers must be replaced on a spot basis to reduce risks of PCB contaminated oil spills. (More information on Toronto Hydro's PCB risk reduction strategy is provided at the end of this section.)

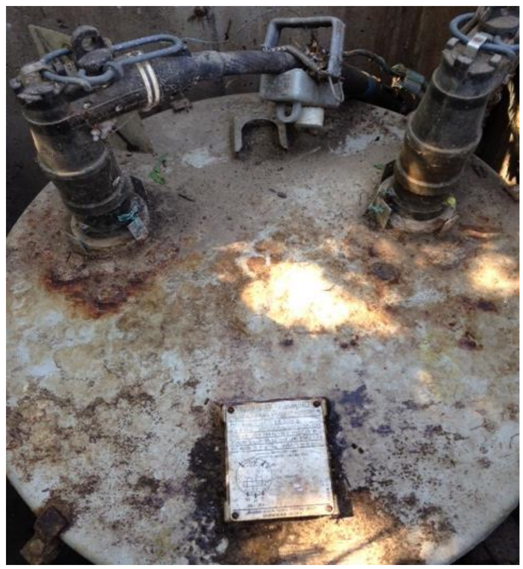


Figure 22: Corrosion on top of a Submersible Transformer

The Underground System Renewal – Downtown program also introduces a proactive cable chamber renewal plan. Toronto Hydro has historically managed these civil assets reactively. However, the latest Asset Needs Assessment identified a significant population of cable chambers with at least material deterioration. There are 89 cable chambers currently in HI5 condition and 398 in HI4 condition. Managing the condition-related risk of failure of cable chambers is essential to ensuring the safety and long-term viability of the underground system. Toronto Hydro developed a plan to rebuild an estimated 75 cable chambers and an estimated 120 cable chamber roofs proactively over the 2020-2024 period to help prevent condition demographics from deteriorating further.

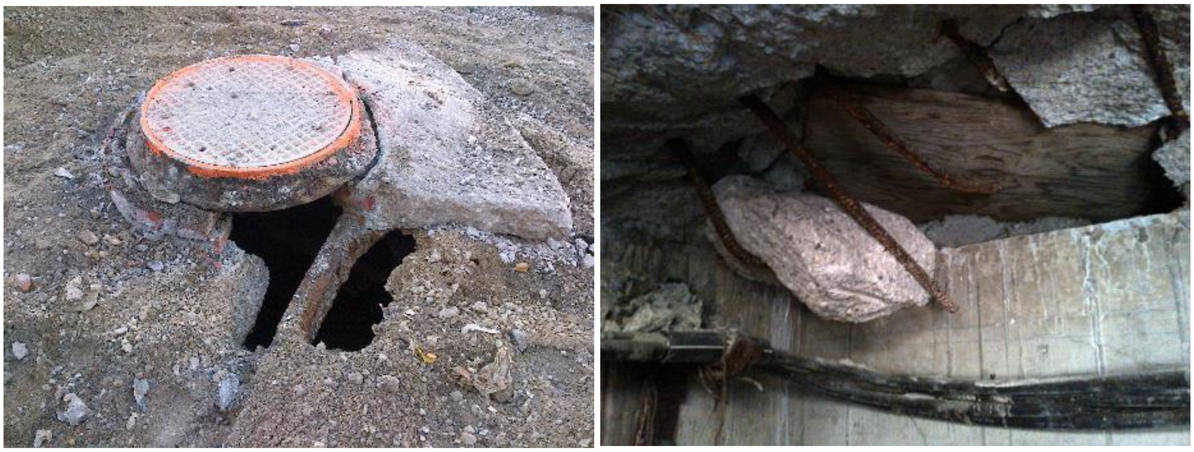


Figure 23: Cable Chamber roof in HI5 condition (left), Cable chamber roof inside view (right)

3. Network Asset Renewal Investments

Failure and obsolescence risks related to network system assets are addressed by Toronto Hydro's Network System Renewal (Section E6.4) and Reactive and Corrective Capital (Section E6.7) programs. The utility paced the 2020-2024 expenditure plans for these programs to maintain current system reliability performance; improve resiliency and operational efficiency of the network; prevent age, condition and obsolescence related asset risk from accumulating over the period; and to continue to reduce and eliminate safety and environmental risks (and other deficiencies) associated with legacy assets and asset configurations.

As discussed in Section D2.2.3, the network system is designed to handle normal failure scenarios better than Toronto Hydro's other system configurations. For this reason, it plays an important strategic role in meeting the reliability expectations of interruption-sensitive customers in the City's core, which contains dense, high-traffic commercial and residential areas. However, in the case of catastrophic failures such as a vault fire, the entire secondary network grid that is connected to the vault must be dropped (i.e. de-energized) until the situation can be safely remedied, which can take over 24 hours. Furthermore, these types of failures can result in risks to public safety and the environment. To minimize these scenarios, Toronto Hydro takes a highly proactive approach to network equipment and vault maintenance and renewal.

Figure 24: Damage from a network vault fire

As noted in Section D2.1.2, seven of the 10 highest rainfall years on record have occurred in the last decade, raising the risk of flooding on the network system. Toronto Hydro developed a plan for the 2020-2024 period that targets non-submersible network units, as these units are susceptible to water ingress and elevated failure risks even when in good condition. In Phase 2 of Customer Engagement, customers expressed support for reducing the risk of network vault fires and flooding,[8] and Toronto Hydro is pacing investments to accomplish this outcome. Condition projections suggest that 267 units will be in HI4 and HI5 condition by 2024 without intervention. Toronto Hydro is planning to replace 43 units in 2018-2019 and 200 units in 2020-2024. Given customer interest in this program's objectives, Toronto Hydro plans to report its progress on this plan as a 2020-2024 Custom Performance Measure under the Safety outcome category (see Section C).

The utility also plans to complete its planned replacement of obsolete and high-risk Automatic Transfer Switches and Reverse Power Breakers, first introduced in the utility's 2012-2014 capital plan, by 2022. These assets are prone to catastrophic failure due to functional obsolescence and can no longer be easily repaired.

To mitigate risks to public and employee safety, the utility also plans to continue proactively renewing network vaults in poor condition. As shown in Figure 25 below, the number of vaults in HI4 and HI5 condition is expected to grow from 40 to over 110 by 2024 without intervention. Network vault rebuilds are complex projects in congested areas and require significant planning efforts,

[8] Exhibit 1B, Tab 3, Schedule 1, Appendix A, Appendix 2.3, p. 28

making it necessary for the utility to maintain a steady and proactive renewal program over time. The utility is planning to proactively address 33 vaults over the 2020-2024 period.

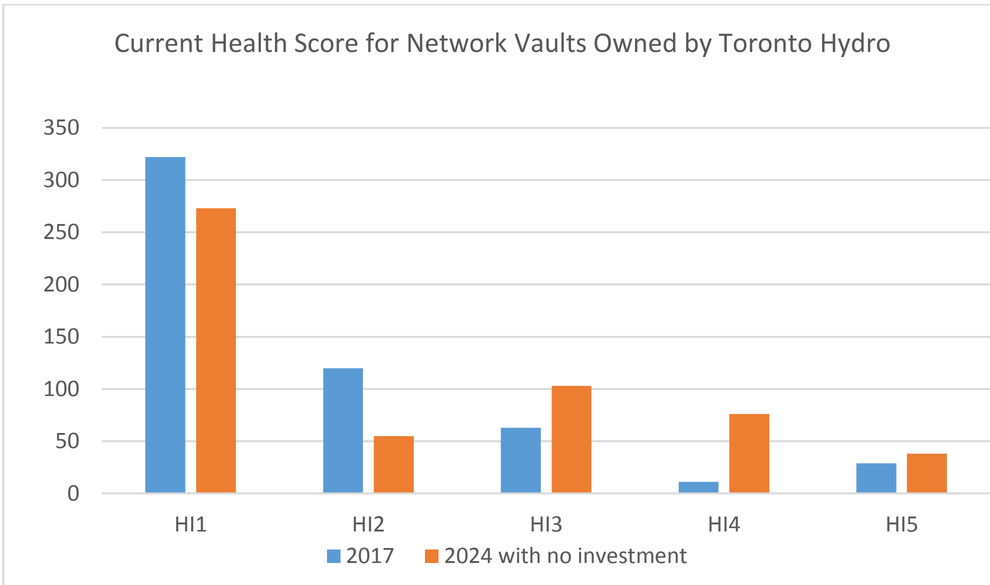


Figure 25: Current and 2024 health scores for Toronto Hydro network vaults.

4. Stations Renewal Investments

Failure and obsolescence risks related to stations assets are addressed by Toronto Hydro's Stations Renewal (Section E6.6) and Reactive and Corrective Capital (Section E6.7) programs. Stations assets are the highest criticality assets on the system due to their potential for causing widespread and lengthy interruptions in the event of failure. (For more information on Stations failure impacts, refer to Section E6.6.) Stations asset replacement projects are highly complex and typically require long lead and execution timelines. In light of these operational constraints and a growing backlog of stations renewal needs, Toronto Hydro developed a plan for the 2020-2024 period that addresses stations equipment at a faster pace than in the 2015-2019 period. This pace of execution has been enabled by a focused effort by the utility to expand its resource pool for stations project design and field work, and other operational improvements. The utility expects to be able to perform previously delayed stations renewal work in the downtown area due to the impending completion of the Copeland Transformer Station ("TS") project, which will alleviate operational constraints in the core of the City. The work planned for the 2020-2024 period must be performed to support the utility's safety, reliability, and resiliency objectives, and to ensure that stations-related asset risk does not increase to unsustainable levels.

The Asset Needs Assessment for stations assets identified a significant backlog of aging equipment, with 40 percent of switchgear, 51 percent of power transformers, 13 percent of outdoor breakers, and 35 percent of DC battery systems operating at or beyond their useful life. The need for investment was further underscored by the high proportion of assets in moderate, material, and end-of-serviceable-life condition, as shown in Figure 26 below.

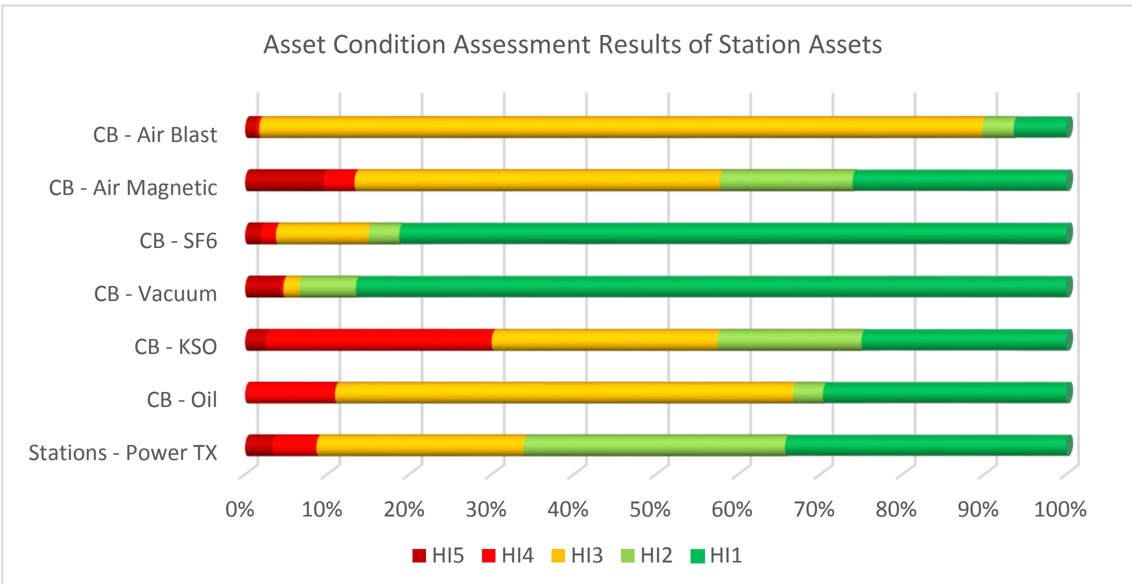


Figure 26: Asset Condition Assessment of Station Assets

Overall, in support of its objectives to maintain reliability, improve system resiliency, and manage the long-term viability of the distribution system, Toronto Hydro developed plans to execute the following work in the 2020-2024 period:

- Replace five TS switchgear units – serving the highest-density areas of Toronto – all of which are beyond their 50-year useful life and feature obsolete circuit breaker designs contained within non-arc resistant enclosures (elevating safety risks for employees);
- Replace nine TS outdoor circuit breakers prioritized based on condition, age, load served, and PCB content;
- Replace 61 TS outdoor switches that are beyond their 50-year useful life, reducing the risk of lengthy interruptions for customers in the North York area of Toronto;
- Remove 12 aging and deteriorating Municipal Station (“MS”) switchgear with obsolete oil circuit breakers and a lack of SCADA functionality;

- Replace 10 power transformers, all of which will be older than 60 years of age by the time of replacement and have identified condition concerns such as high power factor and low insulation resistance;
- Replace 11 end-of-life MS primary supplies, all but one of which will have assets older than 60 years of age at the time of replacement;
- Renew critical stations communications infrastructure – including installing six new remote terminal units ("RTUs"), renewing 39 existing RTUs, upgrading protections at five pilot-wire locations, and replacing 45 kilometres of old copper control cable – to improve system resiliency and maintain overall stations reliability; and
- Renew end-of-life stations battery and ancillary systems.

5. PCB Risk Reduction Strategy

A driver and prioritization consideration for multiple renewal programs is Toronto Hydro's risk mitigation strategy for PCB contaminated oil spills. As explained in Section D2, Toronto Hydro defines "PCB at-risk equipment" as an asset that (i) is known to contain oil with greater than 2 ppm concentration of polychlorinated biphenyl ("PCB"), or (ii) has an unknown concentration of PCB and was manufactured in 1985 or earlier (and is therefore at a high risk of containing PCBs). Due to the toxic and persistent nature of PCB, Environment Canada's PCB Regulations prohibit the use of equipment that contains greater than 50 ppm PCBs, or the release of greater than one gram of PCBs, which could result from an oil leak with significantly less than 50 ppm. The City of Toronto also enforces its own PCB-related bylaws with a near-zero tolerance for the discharge of PCBs into the storm and sanitary sewer systems. The vast majority of PCB at-risk equipment will be operating beyond useful life by 2020, necessitating a proactive strategy to avoid the significant and highly undesirable consequences of a PCB contaminated oil spill on the environment and local communities.

Toronto Hydro is endeavouring to eliminate the risk of oil spills containing PCBs on its overhead, underground, and network systems by 2025 through inspection and testing under its maintenance programs (discussed in Exhibit 4A, Tab 2, Schedules 1-4) and through targeted asset replacement in capital programs such as Overhead System Renewal (Exhibit 2B Section E6.5), Underground System Renewal (Sections E6.2 and E6.3), Stations Renewal (Exhibit 2B Section 6.6), and Reactive and Corrective Capital (Section E6.7). Refer to each of these programs for a description of how the planned investments address PCB at-risk equipment. Due to the importance of this strategy, Toronto Hydro is proposing to track and report the number of PCB contaminated oil spills as a Custom

Performance Measure during the 2020-2024 period, with an objective to improve this environmental outcome over the period. Refer to Section C for more information.

6. Grid Modernization in System Renewal

Toronto Hydro's ongoing grid modernization efforts are supported by System Renewal activities such as Stations Control and Monitoring, Network Unit Renewal, and various other programs that replace deteriorating and obsolete assets with assets that have remote capabilities. These investments help to support reliability outcomes and improve operational efficiency.

E2.2.3.3 System Service Program Expenditures

Toronto Hydro developed a 2020-2024 System Service expenditure plan that targets a select number of system enhancement needs that support the utility's asset management objectives for the period and deliver customer value using technology-driven solutions.

Table 4: 2020-2024 System Service Expenditure Plan ($ Millions)

Programs	2020	2021	2022	2023	2024
Energy Storage Systems	1.0	3.7	3.8	1.0	1.0
Network Condition Monitoring and Control	7.6	10.2	12.6	15.3	17.4
Stations Expansion	19.5	40.0	49.3	12.5	15.2
System Enhancements	6.2	6.2	5.6	4.8	4.9
System Service Total	**34.2**	**60.1**	**71.3**	**33.6**	**38.5**

1. Capacity Expansion and Demand Response

The largest investment for the 2020-2024 period is in the Stations Expansion program (Section E7.4). However, with the Copeland TS project coming to a close in 2015-2019 and a stable overall system loading trend, the stations level capacity needs for the 2020-2025 period are lower than in Toronto Hydro's previous DSP.

Investments for the 2020-2024 period are driven by anticipated bus-level constraints for stations serving areas of high growth and development, and are fully aligned with the results of IRRP activities conducted in coordination with the IESO and Hydro One. The most recent planning document from this process is the Needs Assessment Report for the Toronto Region ("Needs Assessment" or "NA"). Refer to Section B for more information on coordinated system planning with third parties. The planned expenditures will add or free-up over 400 MVA, supporting the sustainment of reliability, operational flexibility, and connections capabilities as indicated by Toronto Hydro's proposed System Capacity measure (see Section C).

Toronto Hydro's expansion plans and their alignment with regional planning outputs are summarized in Tables 5-7 below.

Table 5: Needs Identified in Previous Regional Infrastructure Plan ("RIP")

Needs Identified in Previous RIP	NA Report Section	RIP Report Section	Stations Expansion Narrative
South-West Toronto – Station Capacity	*7.2.1*	*7.2*	Addressed with Horner expansion in 2020-2024 Stations Expansion plan.
Downtown District – Station Capacity	*7.2.2*	*7.3*	Addressed with Copeland TS – Phase 2 expansion in 2020-2024 Stations Expansion plan.

Table 6: End-of-Life Assets – Metro Toronto Region

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Narrative
Charles TS T3/T4 Transformers	*2024-2025*	EOL Transformers and other high voltage ("HV") equipment are identified at these stations for replacement with higher rated equipment, and are discussed further in Section 7.1.1.2 of NA report	Included in 2020-2024 Stations Expansion plan.
Duplex TS: T1/T2 Transformers	*2023-2024*		Included in 2020-2024 Stations Expansion plan.
John TS: T1, T2, T3, T4, T6 Transformers and 115 kV breakers	*2024-2025*	EOL Transformers and other HV equipment are identified at these stations where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.3 of NA report.	Included in 2020-2024 Stations Expansion plan.

Table 7: 2020-2024 Hydro One Contribution Projects based on the most recent Needs Assessment report

Project	Project Type
Horner Expansion	Station Capacity Expansion
Charles TS – T3/T4 Upgrade	Transformer Upgrade
Duplex TS – T1/T2 Upgrade	Transformer Upgrade
Windsor TS – T1/T2/T3/T4 Upgrades	Transformer Upgrade
Finch TS B-Y Replacement	Bus Replacement

In addition to traditional expansion investments, the Stations Expansion program includes a continuation of Toronto Hydro's "Local Demand Response" activities introduced in the 2015-2019 DSP. These "Conservation First" investments involve installing battery storage and implementing targeted demand response incentive programs to reduce peak demand by 10 MW, allowing the utility to defer an estimated $135 million of expansion investments at Cecil TS and Basin TS. These investments support the utility's 2020-2024 objectives of responding effectively to Public Policy and minimizing average rate increases over the period.

2. System Design Enhancements and Modernization

Through the Asset Needs Assessment and the Portfolio Planning process, Toronto Hydro identified several targeted opportunities to address asset risk and enhance customer value by improving system design and investing in system modernization. The bulk of this planned investment is in the System Enhancements (Section E7.1) and Network Condition Monitoring and Control (Section E7.3) programs. These programs will continue Toronto Hydro's efforts to identify spots on the system where asset failure risk can be mitigated, outage restoration capabilities improved, and future operational costs reduced through the installation of protection devices and remote SCADA-enabled switches and sensors.

The Network Condition Monitoring and Control program is new for 2020-2024 and arose out of the need to address performance risks and connection capability challenges on the network system. These issues risk eroding the long-term viability of the network at a time when its compact and reliable design is becoming an increasingly effective option for medium and large customers in developing, high-density areas of the City. Toronto Hydro's modernization strategy for the network will see the utility target 90 percent coverage of the network system with SCADA enabled monitoring and control capabilities by 2024. This highly cost-effective investment supports multiple outcomes by allowing the utility to: (i) remotely identify flood, fire and oil deficiency risks to prevent outages and environmental and safety incidents; (ii) improve resiliency by sustaining service for significantly more customers during multiple contingency events; (iii) gain accurate real-time loading information, which will allow Toronto Hydro to more efficiently connect more customers to the network; and (iv) reduce maintenance costs through remote condition monitoring. Toronto Hydro's planned pacing in this program is aligned with strong customer support received in Phase 2 of Customer Engagement (see E2.3 below).

The utility is also proposing a continuation of its Energy Storage Systems program (Section E7.2) in 2020-2024, with modest investments planned to support grid performance (e.g. power quality issues) and to enable the connection of renewable generation projects. Toronto Hydro is also planning to offer customer-specific battery storage solutions in accordance with "beneficiary pays" principles. For more information, refer to Section E7.2.

3. Grid Modernization in System Service

Most of the investments in the System Service category support the further expansion of grid modernization technologies across the system, including energy storage systems and SCADA-enabled monitoring and control equipment.

E2.2.3.4 General Plant Expenditures

Toronto Hydro developed a General Plant expenditure plan leveraging the asset management principles and strategies outlined in Sections D4 ("Facilities Asset Management"), D5 ("IT Asset Management"), and Section E8.3 ("Fleet and Equipment Services"). The utility held overall expenditure levels in this category in line with spending of the 2015-2019 period. Investments in this category are necessary to keep the utility running efficiently and effectively and are generally driven by lifecycle cost management principles, business continuity needs, and emerging customer needs and preferences.

Table 8: 2020-2024 General Plant Expenditure Plan ($ Millions)

Programs	2020	2021	2022	2023	2024
Facilities Management and Security	11.6	11.8	12.1	12.3	12.6
Fleet and Equipment	8.6	8.9	8.5	8.7	7.8
IT/OT Systems	54.8	55.7	49.5	56.6	64.8
Control Operations Reinforcement	3.9	17.4	18.9	-	-
General Plant Total	**78.8**	**93.7**	**89.0**	**77.7**	**85.2**

1. Fleet and Facilities

The utility's 2020-2024 Facilities Management and Security (E8.2) and Fleet and Equipment (E8.3) needs are primarily driven by asset obsolescence, condition and lifecycle cost analysis for major work centres, stations buildings, physical security systems, and vehicles. Toronto Hydro's planned investments in these programs are optimized to minimize overall lifecycle costs, mitigate safety and security risks, improve efficiencies, and ensure business continuity.

2. Information and Operational Technology (IT/OT)

The utility's planned IT/OT Systems investments (E8.4) for the 2020-2024 period are primarily directed at maintaining current business capabilities, with the remainder directed at expanding existing business capabilities or driving new ones in alignment with outcome objectives and customer needs. The IT/OT program consists of the following key elements:

- **IT Hardware:** Planned expenditure levels were developed to align with asset lifecycles for backend assets (e.g. servers) and endpoint assets (e.g. laptops) that require replacement, and to meet anticipated business needs as forecasted through business planning.
- **IT Software:** Planned expenditure levels were developed in anticipation of upgrade requirements (i.e. security patches, version upgrades to secure vendor support, etc.) for major IT systems such as the utility's Enterprise Resource Planning ("ERP") and Customer Information System ("CIS"), as well as minor applications. Expenditures also include software enhancements to improve and expand business functionality (e.g. data analytics), including responding to emerging business risks (e.g. cybersecurity), customer needs and preferences (e.g. credit card processing), and regulatory compliance needs.
- **Communication Infrastructure:** Planned expenditure levels were developed to address communications infrastructure that is relied upon by core utility operations to maintain and

operate the distribution system in a safe and reliable manner. Proposed investments will address functional obsolescence and reliability risk (e.g. upgrading the communications technology that supports the utility's critical SCADA system), safety and operational risks (i.e. underground radio expansion) and support for system modernization investments (e.g. fibre-optic plant replacement and expansion to support Network Condition Monitoring and Control).

To inform the level of overall IT/OT expenditures, Toronto Hydro procured an independent benchmarking study by Gartner Consulting (see Section E8.4, Appendix A), which concluded that the utility's total IT expenditures per user in both 2017 and 2020 benchmark competitively against industry peers. Gartner also concluded that, in both years, the distribution of Toronto Hydro's IT investments "by cost category, investment category, and functional area are all comparable to the peer group, with some variation but no significant issues identified."

3. Control Operations Reinforcement

As discussed in Section D2, with the growing economic and institutional importance of the City of Toronto and the existence of threats from factors such as climate change and terrorism, operational resilience of the utility is becoming a greater concern for Toronto Hydro, its stakeholders and its customers. Prior to the business planning process, Toronto Hydro re-evaluated the resiliency of its primary control centre operations and performed a gap analysis on its existing and limited backup control centre. The results of this analysis led to the identification of the need to create a fully functional dual control centre at a separate physical location from the existing primary control centre. Toronto Hydro plans to install this control centre during the 2020-2024 period.

To assess Toronto Hydro's investment in a dual control centre, the utility retained London Economics International ("LEI") to undertake a review of comparator utilities (see Section E8.1, Appendix A). LEI completed a review of various utilities in North America that have distribution operations with more than one control centre. These facilities were fully functional and were able to take over full operational functions from the primary control centre. The review confirmed that utilities serving a critical load in North America invest in more than one fully functioning control centre to support resiliency, increase reliability, and ensure quick recovery from terrorist threats and natural disasters, for example earthquakes and floods.

4. Grid Modernization in General Plant

Grid modernization efforts are supported by various IT software and communications investments (e.g. telecom installation) during the 2020-2024 period. The Control Operations Reinforcement program will also support continuity of grid monitoring and control operations in emergencies.

E2.2.4 Portfolio Reporting

The Portfolio Reporting element of IPPR directly informed the development of capital program expenditure plans for the 2020-2024 period. In particular, Toronto Hydro analyzed actual project accomplishments and costs in each program to establish the project- and/or volume-based assumptions that would form the basis of the high-level program cost estimates for the 2020-2024 period.[9] Due to the unique nature of work in each capital program (e.g. large discrete assets vs. area rebuilds; like-for-like vs. reconfiguration), Toronto Hydro's planners relied on different estimating approaches for different programs, leveraging both historical information and professional judgement. These assumptions were challenged and refined throughout the IPPR process and business planning.

E2.2.4.1 Capital Program Efficiency and Unit Cost Benchmarking

To assess the actual efficiency with which Toronto Hydro executes its system investment and maintenance programs, the utility retained UMS Group ("UMS") to perform a capital and maintenance unit cost benchmarking exercise. The utility provided UMS with actual, all-in capitalized unit costs for major asset classes for the 2014-2016 period. UMS performed a normalized comparison of these results to those of peer utilities across North America. The results of this analysis are provided in Table 9 below.

[9] For many DSP programs, it is practically infeasible to develop project-specific details for a five to seven year planning horizon. Planners used a mix of analogous and parametric estimating techniques to create high-level estimates for the programs in these situations. Analogous estimating involves creating a "top-down" estimate of a project's cost and duration using experience with similar projects. Parametric estimating involves identifying volumetric costs and scaling the project or program estimate by the volume of units.

Table 9: Results of UMS Group's Unit Cost Benchmarking Study

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

As seen above, Toronto Hydro compared favourably to its industry peers in nearly all areas. These results provide an indication that the utility has delivered its large capital program cost-effectively through rigorous project development, program management, procurement, and execution practices. For the full UMS report, please refer to Exhibit 1B, Tab 2, Schedule 1, Appendix B.

E2.3 Customer Priorities, Needs and Preferences in Capital Planning

As described in Section 1B, Tab 3, Schedule 1, Toronto Hydro undertook extensive Customer Engagement as part of business planning for this application. The utility augmented its routine, ongoing customer engagement by engaging Innovative Research Group ("Innovative") to design and implement a planning-specific Customer Engagement process. This process was structured in two phases:

- In **Phase 1,** Innovative used a range of techniques to assess customers' needs and preferred outcomes. Quantitative methods provided statistically-valid results (e.g. surveys directed at residential, small business and Key Accounts customers). Qualitative methods provided constructive context to the statistical results (e.g. focus groups directed at residential, small business and mid-market customers). The results of this phase directly informed the strategic parameters for the business plan and informed decision-making throughout the planning process that produced the penultimate capital expenditure plan.
- In **Phase 2**, Innovative took Toronto Hydro's plan back to customers to: (i) confirm the needs, preferences and priorities identified in Phase 1, (ii) solicit customer feedback on the utility's penultimate plan, and (iii) explore trade-offs for certain capital programs. The utility used the results of this phase to refine its business plan.

Further details on the engagement process, the methods used, and the engagement results can be found in Section 1B, Tab 3, Schedule 1 ("Customer Engagement") and in the final report from Innovative ("the Innovative Report") at Section 1B, Tab 3, Schedule 1, Appendix A. The following sections provide a detailed overview of how the Customer Engagement results are reflected in the 2020-2024 Capital Expenditure Plan.

E2.3.1 Phase 1 Customer Engagement Results

Key results of Phase 1 included identifying the outcomes that Toronto Hydro's customers care about (i.e. their priorities) and understanding how they rank those priorities. Low-volume (i.e. residential and GS < 50 kW) customer focus groups conducted at the beginning of Phase 1 provided the qualitative information necessary for Innovative to identify the following set of customer priorities:

1) Delivering reasonable electricity prices;
2) Ensuring reliable electrical service;
3) Ensuring the safety of electrical infrastructure;

4) Providing quality customer service;
5) Helping customers with electricity conservation and efficient usage; [10] and
6) Enabling the electrical system to support the reduction of Greenhouse gases.[11]

Toronto Hydro used this list to develop a customer-focused Outcomes Framework, in alignment with both the utility's corporate strategic pillars and the outcomes and performance categories of the *Renewed Regulatory Framework* ("RRF"). The resulting framework, depicted in Figure 2 in Section E2.1, is focused on six key outcomes: Customer Service, Reliability, Safety, Environment, Public Policy (which includes enabling the system to support the reduction of greenhouse gases), and Financial (which includes delivering reasonable electricity prices). This became the lens through which the utility assessed the value to customers of its capital (and OM&A) program expenditure proposals during business planning. As planning progressed, the utility developed measurable objectives for its plan in each of the six outcome categories, and developed specific objectives at the program level that linked to these measurable objectives, resulting in an outcomes-oriented business plan and DSP. Refer to Exhibit 1B, Tab 2, Schedule 1 for more details on the structure of this framework and its alignment with the RRF and Toronto Hydro's strategic pillars.

In addition to identifying and categorizing customers' priorities, Innovative gathered feedback on how customers ranked these priorities. While customer preferences varied somewhat across classes, in Innovative's view, the overall feedback could be characterized by the following common issues:

1) Keeping distribution price increases as low as possible;
2) Maintaining long-term performance for customers experiencing average or better service;
3) Improving service levels for customers experiencing below average service or who have special reliability needs; and
4) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases.[12]

This feedback informed Toronto Hydro's strategic parameters and outcome objectives for business planning. As discussed in Section E2.1 above, the utility sought to minimize rate increases by setting an upper capital expenditures limit that was closest to the baseline "sustainment" scenario shown in

[10] The customer priority "helping customers with electricity conservation and efficient usage" speaks to the Conservation and Demand Management ("CDM") side of Toronto Hydro's business. This priority is addressed in E2.3.1.4 below.
[11] Exhibit 1B, Tab 4, Schedule 1, Appendix A, p. 7
[12] Exhibit 1B, Tab 4, Schedule 1, Appendix A, p. 5

Figure 3 (in Section E2.1), and by limiting price increases for the residential class to no greater than 3.5 percent over the 2020-2024 period. Toronto Hydro concluded that a sustainment level of capital expenditures would provide the minimum funding necessary to:

- hold average reliability steady over the period;
- maintain long-term performance by preventing asset failure risk from increasing over the period;
- deliver targeted improvements to customers with below average reliability service; and
- maintain or, in targeted situations, improve upon the utility's performance in other priority areas (e.g. Customer Service, Safety, etc.).

As explained in Section E2.2.1, the utility refined these strategic parameters into specific asset management objectives for the 2020-2024 period (see Table 1) and developed a penultimate business plan to achieve these objectives. The following subsections describe how each of these objectives aligns with specific Phase 1 Customer Engagement results.

E2.3.1.1 Reliability and Safety Outcomes

1. Customer Views on Reliability and Safety

When asked to score the importance of their priorities (without ranking them against each other) low-volume customers identified safety, reliability and price as equally important and the most important priorities overall.[13] When these customers were then asked to rank their top three priorities, price clearly emerged as the highest priority, with 52 percent of customers choosing it first, followed by reliability at 22 percent, and safety at 8 percent.[14] Innovative notes that while safety drops to third in these rankings, this is in part because customers tend to view safety as "table stakes", i.e. a baseline requirement of a utility's operations.[15] As expressed in Toronto Hydro's corporate strategic pillars, the utility is fully aligned with customers on this point: public and employee safety is the overarching priority of the utility and is built into its culture, operations, and decision-making frameworks. On reliability, customers overall were generally satisfied with the

[13] Ibid., p. 7
[14] Ibid., p. 8
[15] Ibid., Appendix 1.1., p. 13

current level of service, with support for improving service levels for customers experiencing below average service.[16]

Mid-market customers (i.e. GS > 50 kW) expressed preferences similar to lower-volume GS customers. These customers prioritized "cost containment and short-term rate predictability."[17] Acceptance of "reasonable" rate increases appeared to be conditional in part on maintaining current reliability, which these customers generally viewed as good.[18]

For Toronto Hydro's largest commercial and industrial customers, reliability and price were again top priorities. However, "ensuring reliable electrical service" appeared to be more important for large customers than "delivering reasonable electricity prices".[19] In addition to day-to-day reliability, large customers were specifically concerned about the need to "prevent or reduce the length of prolonged power outages caused by extreme weather".[20] In fact, when large customers were asked to consider the importance of various priorities *without* ranking them, the risk of prolonged outages caused by extreme weather was seen as having the greatest importance.[21] When asked to rank their priorities, this risk came in third, behind price as the second priority and reliability as the top priority.[22] Power quality was not listed as a separate priority from reliability in the ranking exercise; however, in response to an open-ended question about potential improvements in service, 13 percent of large customers identified power quality as an opportunity.[23] Overall, a majority of large customers (56 percent) indicated they would be willing to pay more to maintain or improve reliability.[24]

2. Alignment of the Plan with Customer Preferences for Reliability and Safety

Toronto Hydro's Reliability and Safety objectives for its 2020-2024 Capital Expenditure Plan are aligned with and responsive to the customer feedback summarized above. When it comes to Reliability performance, the utility is seeking to minimize price increases by investing only what is necessary to maintain system reliability at current levels while (i) improving the experience for customers with poor reliability and power quality; and (ii) improving the resiliency of the distribution

[16] Exhibit 1B, Tab 3, Schedule 1, Appendix A, p. 5
[17] Ibid., p. 8
[18] Ibid., p. 9
[19] Ibid., p. 11
[20] Ibid., p. 10
[21] Ibid.
[22] Ibid., p. 11
[23] Ibid., p. 9
[24] Ibid., p. 11

system in light of increasing weather-related risks. As discussed in E2.1 and E2.2 above, the utility's capital expenditure plan is projected to maintain overall SAIDI and SAIFI over the plan period. Toronto Hydro is also proposing the incremental Custom Performance Scorecard measures in Table 10 to track its 2020-2024 reliability performance.

Table 10: Custom System Reliability Measures

Toronto Hydro Outcome	OEB Reporting Category	2020-2024 Custom Performance Measure	Target
Reliability	System Reliability	SAIDI - Defective Equipment	Maintain
		SAIFI - Defective Equipment	Maintain
		FESI-7 System	Improve
		FESI-6 Large Customers	Maintain

The utility added SAIDI and SAIFI for Defective Equipment outages as these measures are an indicator of the age, health, obsolescence, and modernization of system assets, all of which are key drivers of System Renewal and System Service investments during the period. The utility has also included Feeders Experiencing Sustained Interruptions ("FESI") measures to reflect the need, expressed by customers, to improve performance for customers experiencing below-average reliability. Refer to Section C for more information on these measures.

Toronto Hydro's plan also includes investments to improve the resiliency (i.e. the ability to handle emergency events) of the system and utility operations, which aligns with feedback received from commercial and industrial customers. These investments are discussed throughout Section E2.2 and include the renewal of major stations assets in the downtown core (Section E6.6), modernization of the network system (Sections E6.4 and E7.3), remote switching enhancements in the Horseshoe area (Section E7.1), and a project to create a dual control centre (Section E8.1).

As noted above, in addition to sustained outages, some of Toronto Hydro's commercial and industrial customers have expressed a need for improvements to power quality, including momentary interruptions, voltage sags and other issues that can have a significant impact on business operations. The utility is planning to continue addressing these concerns through a combination of targeted activities, including (i) the installation of new ION meters with added functionality that will allow for the diagnosis of customer power quality issues (Section E5.4), (ii) targeted energy storage investments to address grid issues including power quality on poor performing feeders (Section E7.2), and (iii) corrective maintenance and capital investments on worst performing feeders.

Another significant asset management objective related to customers' Safety and Reliability needs is the utility's goal to maintain and, where appropriate, reduce asset failure risk – as represented by leading indicators like asset condition – over the 2020-2024 period. This objective is necessary to support stable system reliability and safety outcomes for customers in the current period and over the long-term, in alignment with many customers' recognition of the need for Toronto Hydro's investments to be future oriented.[25] Section E2.2 describes the various ways in which the goal of either maintaining, or in some cases reducing, the level of asset risk informed the pacing of Toronto Hydro's investment programs. For example, the utility's pacing of pole replacement for the 2020-2024 period is intended to keep the condition demographics of wood poles from deteriorating over the period, which is a key issue for both Safety and Reliability on the overhead system. Similarly, Toronto Hydro plans to pace direct-buried cable replacement with the intention of preventing the significant Reliability risks related to this asset type from increasing to an extent that would result in deteriorating service and high reactive repair costs over the long-term. Given the significant investment that both of these activities drive in the 2020-2024 period, Toronto Hydro has included Custom Performance Scorecard measures that will track the utility's effectiveness in managing these risks, as shown in Table 11 below. Other System Renewal programs have been paced in a similar manner to manage asset risks and maintain performance while minimizing price increases.

Table 11: Custom Asset Management Measures

Toronto Hydro Outcome	OEB Reporting Category	2020-2024 Custom Performance Measure	Target
Reliability	Asset Management	System Capacity	Maintain
		System Health (Asset Condition)–Wood Poles	Monitor
		Direct Buried Cable Replacement	Improve

Toronto Hydro has also included a System Capacity measure under this category. Available capacity is another leading indicator of reliability performance and the ability of the system to handle contingency events. It is also an important indicator of Toronto Hydro's ability to connect customers and carry-out planned capital and maintenance work efficiently. Toronto Hydro plans to maintain current performance for this measure through investments in the Stations Expansion (E7.4) and Load Demand (E5.3) programs.

[25] Example: Ibid., Appendix 1.2, p. 11

In addition to managing failure risks for assets generally, Toronto Hydro set the following Safety-specific objectives for its capital program in the 2020-2024 period:

- Continue to reduce and eliminate public and employee safety risks, for example by removing higher-risk legacy assets from the system within a specific and reasonable timeframe;
- Strive to target zero public and employee safety incidents over the 2020-2024 period; and
- Comply with all safety regulations and standards over the 2020-2024 period.

These objectives are aligned with customer expectations for a safe distribution system. The majority of Toronto Hydro's capital programs address safety risks or improve the safety of the system or the utility's operations. Among these are a number of programs that address higher-risk legacy assets that the utility is aiming to remove entirely. Box construction poles and non-submersible network units are two examples of legacy assets that present risks to employee and public safety in the congested downtown core. Toronto Hydro plans to track its progress in eliminating these assets during the 2020-2024 period with the measures in Table 12.

Table 12: Custom Safety Measures

Toronto Hydro Outcome	OEB Reporting Category	2020-2024 Custom Performance Measure	Target
Safety	Safety	Total Recorded Injury Frequency	Maintain
		Box Construction Conversion	Improve
		Network Units Modernization	Improve

Toronto Hydro also plans to report on its Total Recorded Injury Frequency metric during the 2020-2024 period. This is a long-standing measure of employee safety at the utility.

In addition to the aforementioned custom measures, the utility plans to continue meeting all of the OEB's existing Safety and Reliability performance standards as reporting on the Electricity Distributor Scorecard (refer to Exhibit 1B, Tab 2 for more information).

E2.3.1.2 Customer Service Outcomes

1. Customer Views on Customer Service

"Providing quality customer service" was not ranked as a top three priority in any of the customer classes that were formally surveyed. However, the results of the mid-market focus groups led Innovative to conclude that Customer Service appeared to be the third ranked priority for GS > 50 kW customers. Specifically, providing accurate and proactive communications around outages was seen as a priority, as was enhancing customer service to match emerging technological capabilities (e.g. receiving bills by email and creating master accounts to manage multiple bills).[26]

Where customers in other classes provided feedback on Customer Service, it tended to echo the views of the mid-market GS customers. For example, low-volume customers were also interested in receiving accurate restoration times for outages and were interested in tools to make billing, account management, and usage information easily accessible.[27] Large customers were generally satisfied with their level of Customer Service and were mainly focused on additional support in implementing CDM programs.[28] A minority of large customers identified other opportunities to improve their Customer Service, e.g. improving communications around scheduled outages.

2. Alignment with Customer Preferences for Customer Service

The type of feedback that Toronto Hydro received on Customer Service was generally aligned with what the utility hears from its customers on an ongoing basis. Toronto Hydro is working to continuously improve its capabilities around outage communications, billing preferences, and information accessibility through operational improvements and targeted capital investments; for example, installations of next generation metering technology (Section E5.4) with "last gasp" capabilities will allow the utility to find the specific location of an outage faster, supporting improved outage response and outage communications. Planned IT Software upgrades and enhancements will also support improvements to the customer experience of interacting with the utility through digital platforms, and improvements to accurate and timely communication with customers during prolonged power outages (Section E8.4). With respect to receiving electronic bills and access to usage information and other data, Toronto Hydro plans to continue improving the number of customers on "eBills" and will report this under the Customer Service outcome as a Custom Performance Measure for 2020-2024. The movement to eBills is also a continuing source of OM&A cost savings.

Table 13: Custom Customer Service Measures

Toronto Hydro Outcome	OEB Reporting Category	2020-2024 Custom Performance Measure	Target
Customer Service	**Customer Satisfaction**	Customers on eBills	Improve

[26] Ibid., p. 6
[27] Ibid.
[28] Ibid.

Toronto Hydro generally performs at or above standard on the OEB's Electricity Distributor Scorecard measures and Electricity Service Quality Requirements for Customer Service and intends to continue meeting or exceeding the OEB's standards in these areas. This includes connections activities, which were not a concern of the customers engaged in the Innovative Report (as they were already connected customers), but are nonetheless an important driver of System Access and capacity related investments in the 2020-2024 period. As noted in Table 1, Toronto Hydro's objective is to continue connecting customers of all types (including distributed energy resources) on time and cost-effectively, without harming system performance for existing customers.

E2.3.1.3 Environmental Outcomes

With the exception of enabling the grid to reduce greenhouse gases (which is a Public Policy outcome under Toronto Hydro's Outcomes Framework) customers did not identify the environment as a distinct priority, which could be due to a lack of awareness around the environmental risks or issues related to distribution assets. Operating the utility in an environmentally sustainable manner is an important outcome for Toronto Hydro and one that directly affects customers and stakeholders. For the 2020-2024 period, Toronto Hydro's asset management objectives for the Environment include the following:

- Endeavour to eliminate the risk of PCB-contaminated oil spills by 2025.
- Reduce the system's impact on the environment caused by greenhouse gas emissions and oil leaks of all types.
- Comply with all environmental regulations and standards over the 2020-2024 period.

While the utility's PCB risk mitigation objective for the 2020-2024 period is categorized as an Environment outcome, it is aligned with customer expectations for Safety. As discussed in E2.2.3.2, the risk of PCB oil spills is both an environmental issue and, due to the toxic and persistent nature of PCB, a public health and safety concern. Toronto Hydro is required to address these risks in accordance with legislation and City bylaws, and the utility plans to track and report on the number of spills containing PCBs over the 2020-2024 period as a Customer Performance Scorecard measure, as noted in Table 14. The utility's System Renewal (and maintenance) programs deal with various other environmental compliance risks, including the risk of oil spills generally.

Table 14: Custom Environment Measures

Toronto Hydro Outcome	OEB Reporting Category	2020-2024 Custom Performance Measure	Target
Environment	**Environment**	Oil Spills Containing PCBs	Improve
		Waste Diversion	Monitor

E2.3.1.4 Public Policy Outcomes

While customers typically did not explicitly reference public policy in discussions and responses, many customers did provide feedback on certain topics that are influenced or driven by provincial energy policy. The main focus of customers in this regard was CDM. As noted at the beginning of E2.3.1, "helping customers with electricity conservation and efficient usage" is a common interest across customer classes that speaks to the CDM side of Toronto Hydro's business.[29] As discussed in Section 1B, Tab 2, Schedule 1, Toronto Hydro intends to continue implementing CDM programs and is on track to fulfil its CDM targets set by the IESO by 2020.

Most of the utility's CDM programs are not rates funded. However, the utility's business plan does include a continuation of the utility's targeted Local Demand Response initiative, which features rates-funded demand response activities to defer distribution infrastructure. Details on this activity can be found in Section E7.4 (Stations Expansion). This program supports the "Conservation First" objectives of the Long-Term Energy Plan and contributes to minimizing price increases in the utility's business plan.

Enabling the electrical system to support the reduction of greenhouse gases is another Public Policy related activity that was identified as a priority for customers. While, on net, both low-volume and large customers viewed this priority as important,[30] it did not rank highly compared to other priorities. Large customers ranked this as the lowest priority, while low volume customers ranked it as the fourth most important priority behind Safety and ahead of conservation/efficient usage and Customer Service.[31] For the 2020-2024 period, Toronto Hydro's planned investments in this area are exclusively related to enabling the connection of renewable energy generation ("REG") projects in accordance with the utility's obligation to provide access to generation customers, and in strict alignment with the forecasted volume of REG connections (as reviewed and supported by the

[29] Ibid.
[30] Ibid, p. 7 and p. 10
[31] Ibid., p.8 and 11

IESO).[32] As discussed in E2.2.3.1, Toronto Hydro plans to meet this demand through investments in the Customer Connections program (E5.1), the Generation Protection, Monitoring, and Control program (E5.5), and the Energy Storage Systems program (E7.2). The utility will continue to report its performance in connecting renewable generation customers through the Connection of Renewable Generation measures on the OEB's Electricity Distributor Scorecard.[33]

E2.3.1.5 Financial Outcomes/Price

As noted at the beginning of this section, overall feedback from customers was characterized by a general preference to keep prices as low as possible, balancing other customer priorities with the need to contain rate increases. Low-volume and mid-market customers ranked price as their top priority, while large customers ranked reliability as the top priority, just ahead of price.

As discussed in detail in E2.1 and E2.2, Toronto Hydro developed a capital plan that made the necessary trade-offs between improvements and price to ensure the delivery of performance and service outcomes that align with customer needs and preferences while minimizing bill impacts. Leveraging the outputs of its asset management tools and processes, Toronto Hydro's plan was calibrated to include only the expenditures necessary to meet these objectives, including the overarching customer priorities of maintaining average reliability now and in the long-term, improving resiliency, and prudently mitigating safety risks over the 2020-2024 period.

In addition to the Cost Control measures reported on the OEB's Electricity Distributor Scorecard, and in recognition of the importance to customers of cost control and price mitigation over this period, Toronto Hydro plans to report on the following custom measures as further indication of the cost efficiency of the utility's system plan over time.

Table 15: Custom Financial Measures

Toronto Hydro Outcome	OEB Reporting Category	2020-2024 Custom Performance Measure	Target
Financial	Cost Control	Average Wood Pole Replacement Cost	Monitor
		Vegetation Management Cost per Km	Monitor

These measures are discussed in detail in Section C of the DSP.

[32] Section 2B, Appendix F
[33] Refer to Exhibit 1B, Tab 2, Schedule 1

E2.3.2 Phase 2 Customer Engagement Results

Innovative translated the penultimate plan developed using the Phase 1 Customer Engagement results into consultation materials for the second phase of engagement. The objective of Phase 2 was to:

- confirm the customer needs, preferences and priorities identified in Phase 1;
- solicit customer feedback on Toronto Hydro's planning development process and the content of its proposed plans and subsequent rate impact; and
- identify customer preferences towards particular capital projects where trade-offs on pacing exist.[34]

E2.3.2.1 Needs, Preferences and Priorities

Innovative found that a "strong majority" of customers were both familiar with Toronto Hydro and satisfied with the services they receive.[35] Survey results confirmed that customers in the low-volume classes ranked price as the top priority, reliability as the second priority, and safety as the third. For mid-market GS customers – who were not formally surveyed in Phase 1 – price and reliability continued to be first and second priority, as identified in the previous focus groups; however, safety took the place of outage communications as the third priority.[36] Large customers reaffirmed their priorities related to reliability, price, and outages caused by extreme weather.[37]

A strong majority of customers did not identify any missing priorities from those identified by customers in Phase 1.[38] Furthermore, a clear majority responded that they felt that Toronto Hydro's Customer Engagement process "seemed like a good way to bring customer needs and preferences into Toronto Hydro's plan."[39]

E2.3.2.2 Opinion of Toronto Hydro's Proposed Plan

Innovative initially presented customers with a general description of the approach behind Toronto Hydro's penultimate plan (e.g. "[…] focuses on delivering current levels of reliability") and provided

[34] Ibid., p. 13
[35] Ibid.
[36] Ibid., p. 14
[37] Ibid., p. 19
[38] Ibid., p. 15
[39] Ibid.

them with the associated bill impacts. As noted in the Innovative Report, in the absence of a discussion of specific benefits and trade-offs for customers, a plurality of participants did not agree with Toronto Hydro's approach, which, in Innovative's view, highlighted "the general concern about delivering reasonable electricity prices […]."[40] Innovative notes that "this is the only trade-off question where respondents appear to place price concerns above the maintenance of reliability and targeted improvements," and that "as customers became more engaged in discussing more detailed trade-offs, their responses favoured the other outcomes over bill impacts."[41]

After considering and providing feedback on the pacing and prioritization of various capital programs and activities, customers were asked whether Toronto Hydro should stick with its proposed plan, improve service, or scale back the plan. A majority of customers across all classes either supported sticking with the plan as proposed or improving service. A plurality of customers in the residential and small business (i.e. GS < 50 kW) classes, and a majority of customers in the mid-market class (GS > 50 kW), supported the plan as proposed. Of the 37 large customers that completed the Key Account online survey, 29 felt that Toronto Hydro should either exceed the current plan to improve services beyond what is being proposed (4 of 37) or stick with the current plan and its expressed outcomes (25 of 37).[42]

E2.3.2.3 Program Specific Feedback and Final Plan Adjustments

Customers were asked to provide feedback on the pacing and prioritization of programs in areas where Toronto Hydro felt it could adjust pacing to achieve greater benefits. The two categories of programs that were presented to customers were "Addressing Safety and Reliability" and "Innovation and Planning for the Future". As Innovative notes, "a majority of customers in each rate class support either the current proposed pace of investments or an accelerated approach and associated outcomes for all six programs […]" in the "Addressing Safety and Reliability" category, which included rear lot conversion, direct-buried cable replacement, lead cable replacement, network unit replacement, cable chamber renewal, and contingency enhancements.[43] Under the "Innovation and Planning for the Future" category, customers strongly supported investing in monitoring and control equipment (e.g. Network Monitoring and Control), with more customers

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[40] Ibid.
[41] Ibid. 16
[42] Ibid. 20
[43] Ibid.

indicating that Toronto Hydro should be spending more on these investments rather than reducing the current pace. Customers did not support doing more than planned in the other programs in this category.[44]

As discussed in Sections E2.1 and E2.2, Toronto Hydro took this feedback into account as it refined and finalized its 2020-2024 Capital Expenditure Plan. The utility took customers' support for the overall plan and the Customer Engagement process as confirmation that the plan achieves an appropriate balance between addressing long-term system needs and risks, delivering the outcomes that customers need and prefer, and keeping price increases as low as possible. Given the particularly strong support across customer classes for programs that address the risk of network vault floods and fires (i.e. Network Unit Renewal and Network Condition Monitoring & Control), Toronto made minor adjustments to the pace of these programs to address these issues at an accelerated pace over the 2020-2024 period. Refer to E2.2.3.2 and E2.2.3.3 for more details.

[44] Ibid., p. 17

E3 System Capability Assessment for Renewable Energy and Conventional Generation

This section provides information on the capability of Toronto Hydro's distribution system to accommodate renewable energy generation ("REG") and other distributed generation ("DG") connections. This information includes REG applications, overall DG connection projections, the distribution system's ability to connect, as well as known constraints on the distribution system.

E3.1 Applications

Since the introduction of the *Green Energy and Green Economy Act, 2009*, Toronto Hydro has responded to over 8,000 inquiries from customers and developers seeking to connect generation under various programs such as IESO programs (FIT, HCI, PSUI-CDM, RESOP, HESOP),[1] Net-Metering, Energy Storage, Combined Heat and Power ("CHP"), Closed Transition and Load Displacement. A wide range of proponents have submitted project applications, including many schools, housing developments, large grocery stores, condominium corporations, and department stores.

As of the end of 2017, Toronto Hydro has connected nearly 1,800 unique DG connections to the distribution grid. Figure 1 provides an overview of existing DG connections within Toronto Hydro's service territory. This represents over 225 MW of generation capacity across various types of DG technologies.

[1] Feed-in Tariff ("FIT"); Hydroelectric Contract Initiative ("HCI"); Process and Systems Upgrade Initiative – Conservation Demand Management (PSUI-CDM"); Renewable Energy Standard Offer Program ("RESOP"); and Hydroelectric Standard Offer Program ("HESOP");

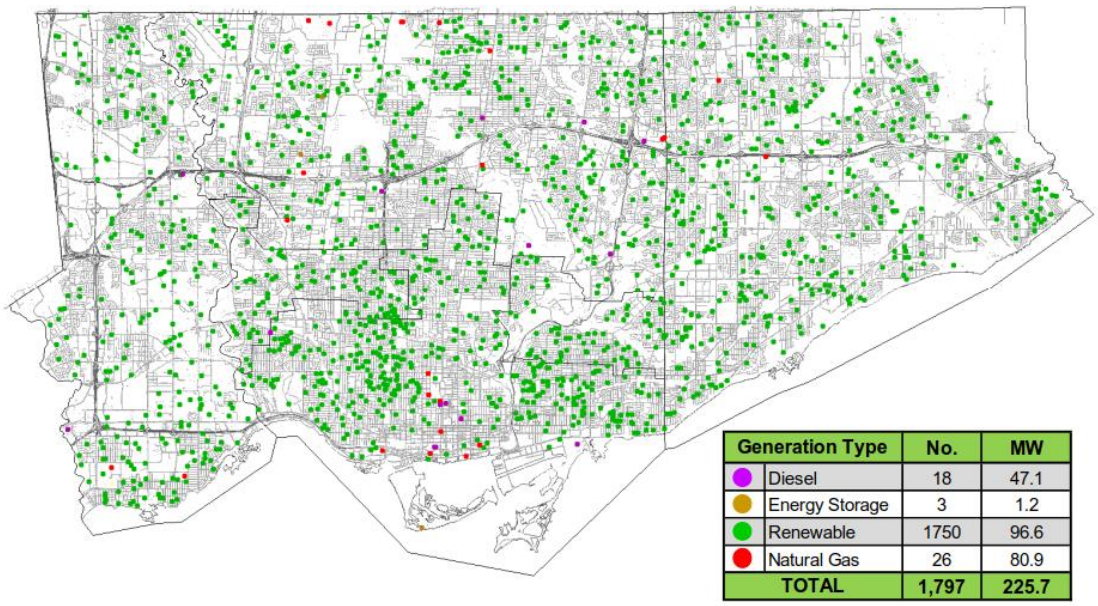


Figure 1: Toronto Hydro DG Connections (as of December 31st, 2017)

From 2014 to 2017, Toronto Hydro connected about 131 MW of generation to its distribution system, which represents roughly 43 percent of the connected capacity that was projected for the same time period in the 2015 CIR application. The lower the expected DG capacity connected during this period can be attributed to various reasons:

- Eight medium and large DG's totalling about 32 MW were cancelled by the customer.
- 14 medium and large DG's totalling about 76 MW deferred by the customer and are expected to be installed between 2018 and 2020.
- 12 new medium and large DG's totalling about 43 MW were forecasted to be connected between 2015 and 2017 based on historical connections and consultations at the time. However, only six new medium and large DG's totalling about 20 MW were connected during this timeframe.
- 114 MW of FIT and microFIT generations were forecasted to be connected between 2015 and 2017 based on the pace of applications and connection requests at the time. However, due to reductions in incentive rates by the IESO, customer interest proved lower than expected and only 70 MW of these FIT and microFIT generations were connected during this timeframe.

E3.2 Forecasted Generation Connections

Interest in generation projects within Toronto Hydro's service territory has been steady in recent years, and is anticipated to continue into the future. In particular, there has been a growing interest in Net Metering and battery energy storage, due to provincial policy changes and falling costs of solar photovoltaic panels, inverters, and lithium-ion batteries. Inquiries regarding conventional generators have also increased as micro-turbine based installations become more economically viable and commercial and industrial customers attempt to increase site reliability and operational cost savings.

Toronto Hydro's 2018-2024 DG connection and capacity forecast takes into account historical connection trends, completed assessments, and anticipated projects with respect to various DG programs. Toronto Hydro used a linear approximation to forecast the anticipated amount of connections and associated capacity from 2018 through 2024. The forecast connection rates of DG and REG are consistent with expectations from the Long-Term Energy Plan and IESO procurement plans and assumes the following:

- The microFIT and FIT program will transition to a net metering program in 2018, as per the directive issued by the Minister of Energy on April 5, 2016.
- No major changes will be introduced to the net metering program from 2020 to 2024
- A steady 3 percent increase year-over-year for REG connections (90 micro and 60 small sized REG connections in 2019 are used as the baseline);
- Increased demand for energy storage connections due to lithium-ion battery prices reductions:
    - 12 micro, five small, and three medium sized energy storage connections in 2019 are used as the baseline. A 20 percent increase year-over-year is used to forecast 2020-2024 connections;
- Increased demand for CHP and diesel connections due to customers seeking site reliability and electricity charge reductions:
    - 15 small and two medium sized natural gas connections in 2019 are used as the baseline. A 15 percent increase year-over-year is used to forecast 2020-2024 connections; and
    - one small and four medium sized diesel connections in 2019 are used as the baseline. An extra unit is forecasted to be added every two years.

DG projects are expected to more than double by 2024, reaching approximately 3,600 connections. This represents an additional 581 MW on top of the 226 MW in connected DG as of December 2017. Forecasts for renewable and conventional generation are shown in Figures 2 and 3 below.

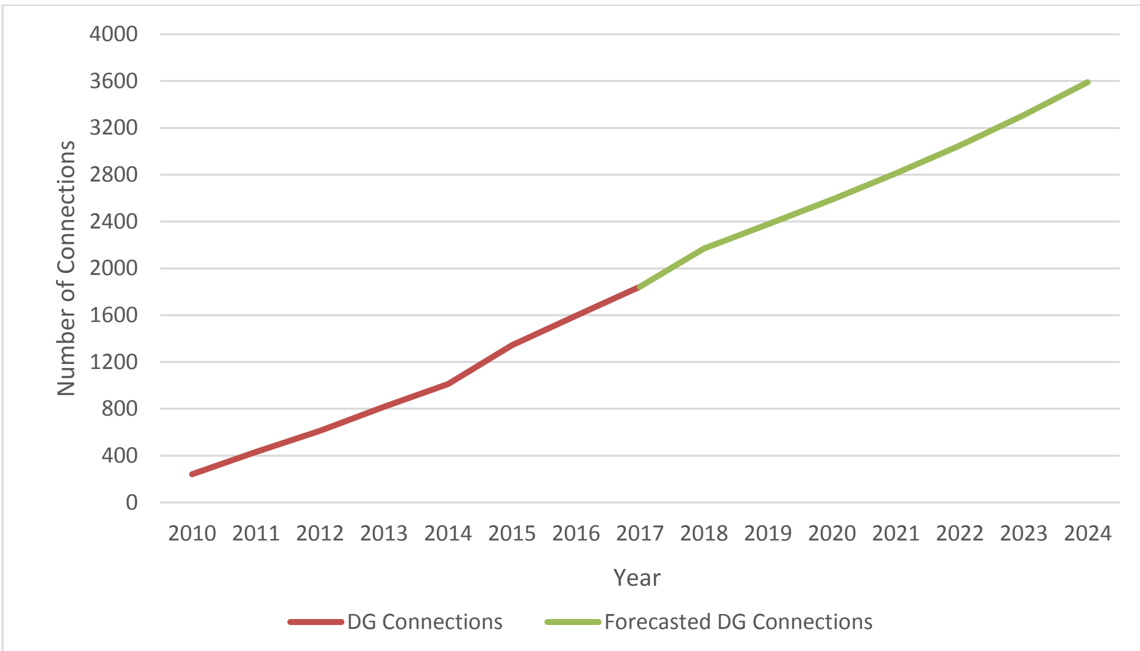


Figure 2: Historical and Forecasted Generation Connections

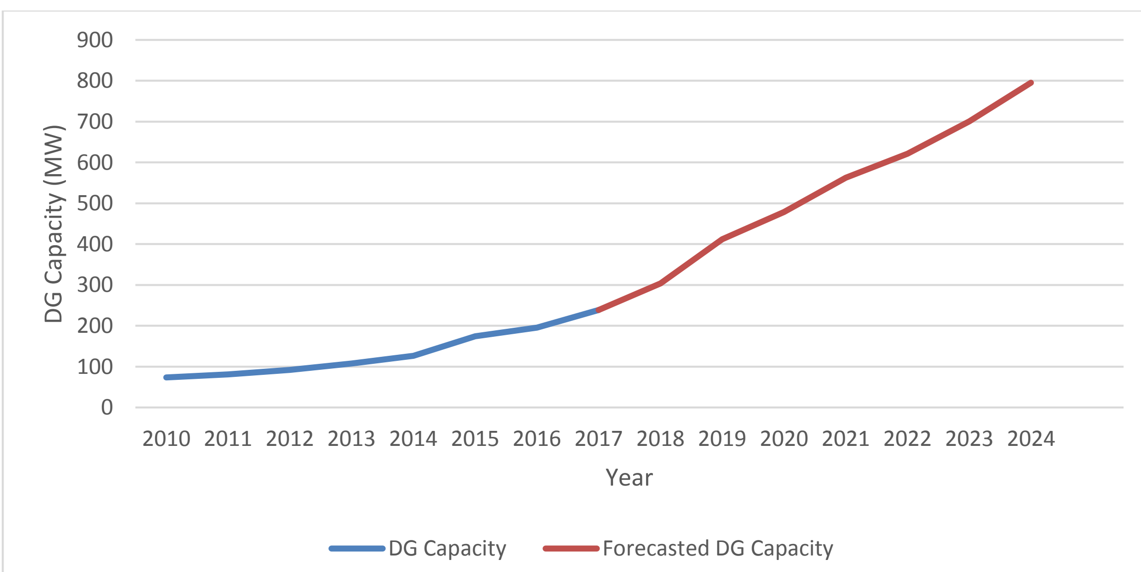


Figure 3: Historical and Forecasted Generation Capacity

E3.2.1 Forecasted Connections for Renewable

The policy and economic conditions within Toronto Hydro's service territory in recent years have facilitated a steady interest in REG projects, which is expected to continue into the foreseeable future. In addition, the combination of decreasing costs of photovoltaic panels and termination of the IESO FIT program has generated growing interest in the IESO Net Metering program.

As of the end of 2017, Toronto Hydro has assessed and approved over 450 micro and small REG projects totalling 31 MW under the microFIT, FIT, and Net Metering programs. These projects are expected to be connected to the distribution system by the end of 2018.

Based on historical trends and given the end of the IESO FIT program in 2018, Toronto Hydro anticipates the pace of REG connections to slow slightly beginning in 2019. However, forecasted REG installations will likely be larger in size compared to the past due to cost reductions in solar photovoltaic panels.

Between 2019 and 2024, Toronto Hydro forecasts roughly 830 additional REG connections (totalling 69 MW) to the distribution system.

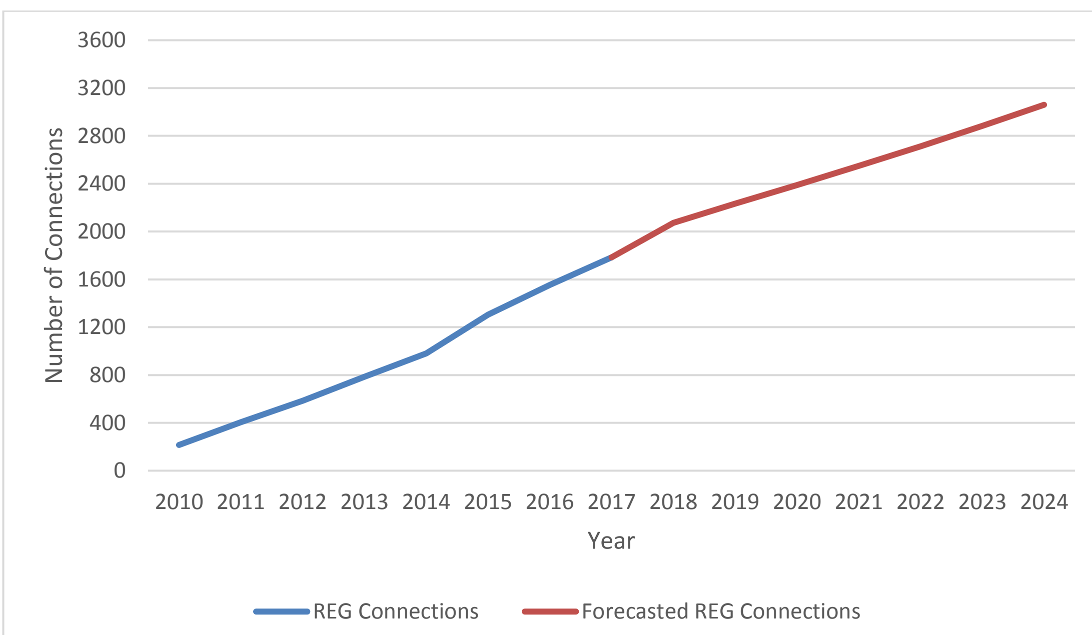


Figure 4: Historical and Forecasted REG Connections

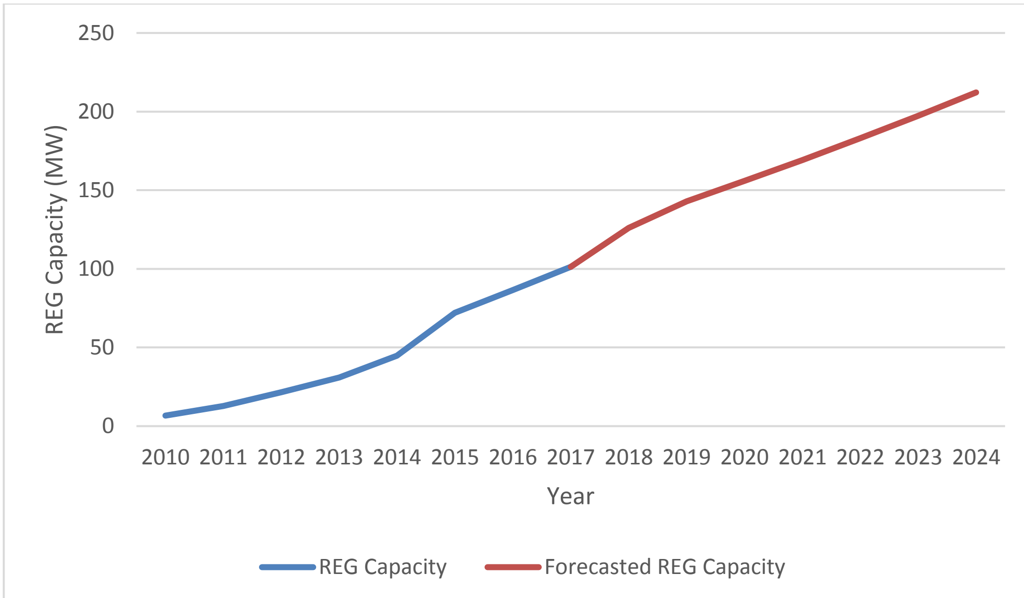


Figure 5: Historical and Forecasted REG Capacity

E3.2.2 Forecasted Connections for Conventional

Inquiries regarding conventional generation connections has also increased in Toronto Hydro's service area in the past few years, primarily due to industrial and commercial customers seeking site reliability and operational cost savings. Specifically, inquiries relating to mid- and large-sized CHP installations have more than tripled from 15 in 2015 to almost 50 in 2017.

Toronto Hydro has also observed increased interest in small scale micro turbine-based installations. As a proven technology that is already in extensive use throughout North America, this type of installation is ideally suited for small-scale power generation in commercial and multi-level residential buildings. The number of connection requests for micro turbine-based CHP jumped from 25 in 2015 to 120 in 2017. Over the 2020-2024 period, Toronto Hydro anticipates a larger volume of applications as more customers become aware of the economic benefits of micro turbine-based CHP.

Battery energy storage is becoming the next major generation technology as costs associated with lithium-ion batteries continue to fall. As a result, Toronto Hydro has seen exponential growth in battery energy storage inquiries. Based on market projections, battery energy storage connections are expected to increase between 15 and 25 percent year-over-year as the technology matures and prices fall to a point where it makes economic sense to invest in battery storage.

Toronto Hydro is aware of 19 CHP, Diesel Closed Transition and Energy Storage projects totalling 124 MW of nameplate capacity. These projects are in various stages of development, and due to being larger in nature, will take longer to be connected to the distribution system. These DG's are anticipated to be connected over the 2018-2020 period.

Toronto Hydro's forecasts for conventional generation are based on initial consultations and preliminary assessments received and completed to date, including potential projects with a relatively high level of intent to proceed under CHP, Closed Transition, Load-Displacement, IESO Energy Storage Procurement Request for Proposal ("RFP"), and other IESO programs such as PSUI.

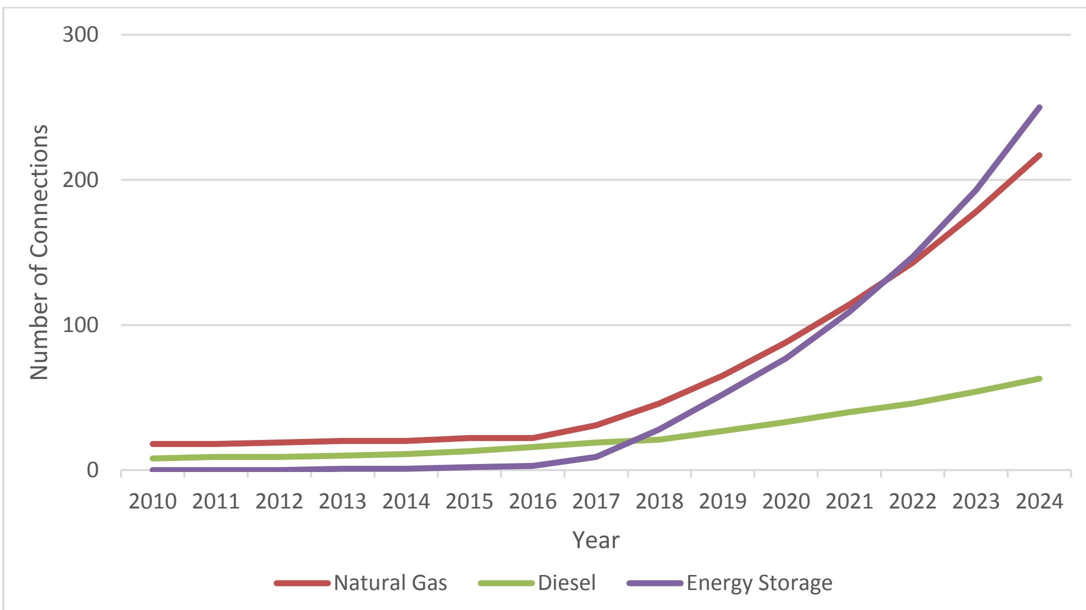
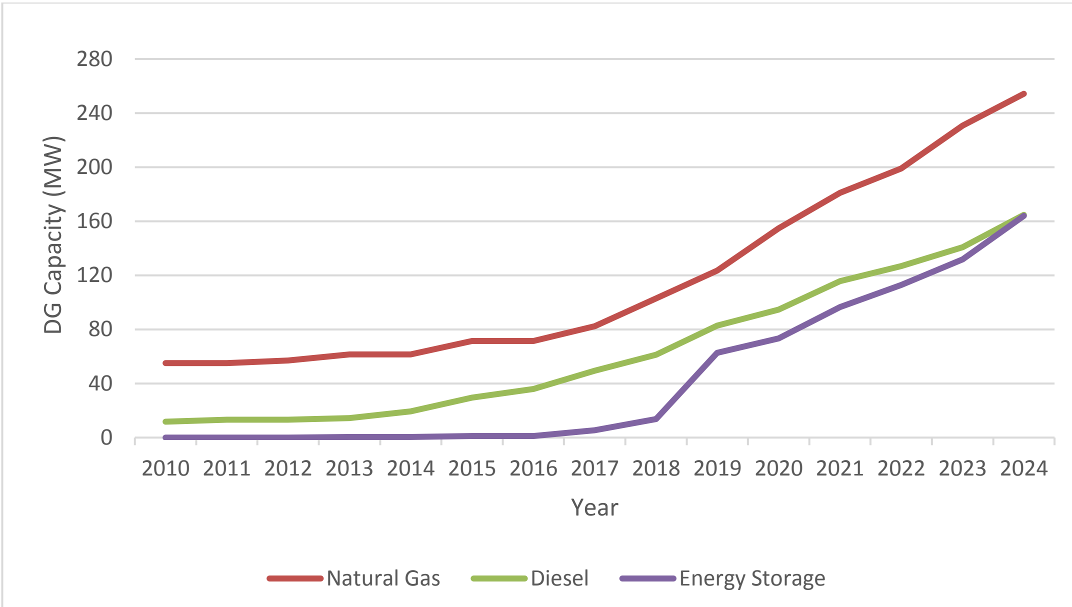


Figure 6: Historical and Forecasted Generation Connections



1 **Figure 7: Historical and Forecasted Conventional Generation Capacity**

E3.3 Capacity and Constraints to Connect Distributed Generation (DG)

E3.3.1 Existing Capacity to Connect

There are several challenges associated with connecting the forecasted 581 MW of DG to the Toronto Hydro system. On the distribution level, short circuit capacity is the main constraint that prevents new DG connections to certain stations.

E3.3.2 Existing Constraints to Connect

There are a number of constraints limiting Toronto Hydro's ability to connect DG, including fault current, thermal limits, anti-islanding, and the ability to transfer loads between feeders in the event of a contingency. The primary constraint at this time is short circuit capacity.

1. Short Circuit Capacity Constraints

To maintain safe and reliable operation of the distribution system, Toronto Hydro cannot connect DG in situations where short circuit capacity limitations exist. The existing distribution based short circuit capacity constraints are identified in Figure 8. This map shows the areas within Toronto that are approaching or have reached short circuit limits at various stations. These stations are supplied by Hydro One Networks Inc. ("Hydro One") transformers and directly connect to Toronto Hydro feeders. Toronto Hydro is proposing to install bus tie reactors to mitigate the existing short circuit capacity constraints, so as to allow the distribution system to accommodate new DG connections. More detailed information is provided in Section E5.5.

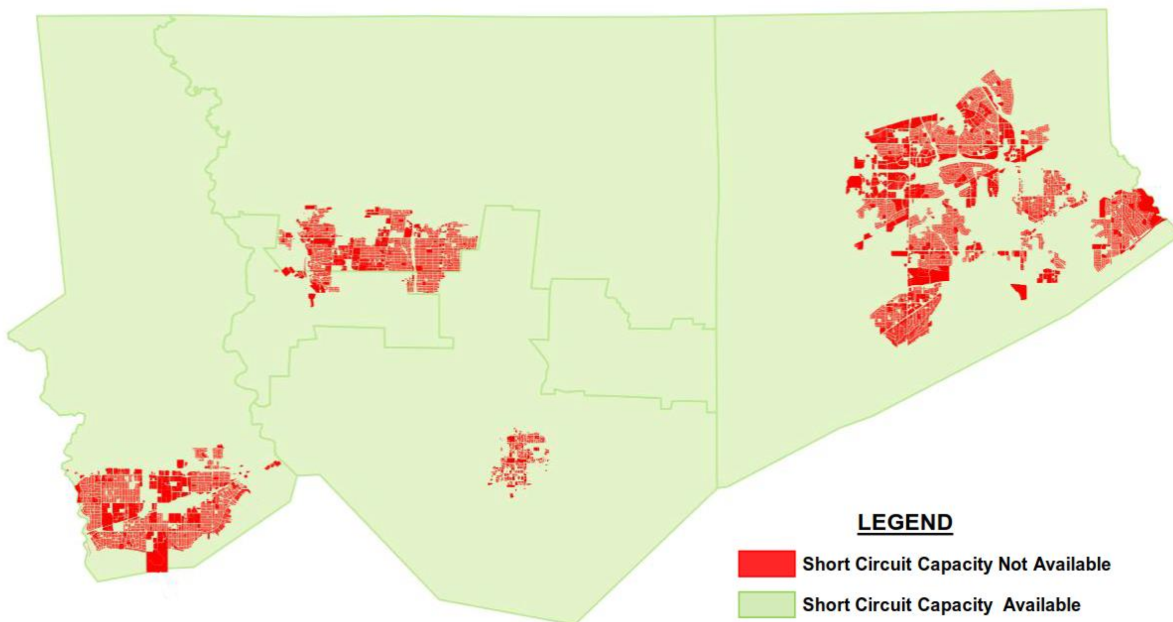


Figure 8: Map of Distribution System Short Circuit Capacity Constraints

2. Anti-Islanding Condition for Distributed Generators

Islanding occurs when a DG source continues to power a portion of the grid even after the main utility supply source has been disconnected or is no longer available. This situation must be avoided as it can interfere with grid protection systems and potentially endanger Toronto Hydro crews.

The connection of photovoltaic solar inverters and other DG sources must be accomplished in a manner that ensures that unintentional islanding of cannot take place. Toronto Hydro plans to deploy real-time monitoring and control investments proposed within the Generation Protection, Monitoring, and Control program at every new DG site to provide the ability to address anti-islanding concerns. More detailed information is provided in Section E5.5.

As the ratio of generation capacity to minimum load increases, the amount of time required by inverters to respond to anti-islanding scenarios also increases and the effectiveness of inverter response to anti-islanding scenarios decreases. Based on common industry practice, Toronto Hydro aims to ensure that “DR aggregate capacity is less than one-third of the minimum load of the Local

Electric Power System (EPS)."[2] Toronto Hydro plans to deploy energy storage investments to help mitigate feeders with high generation to load ratio in order to address anti-islanding concerns. More detailed information is provided in Section E7.2.

3. System Thermal Limits and Load Transfer Capability

For large generation or aggregated generation connections, an important operating limit stems from a feeder's continuous load thermal ratings. Exceeding system thermal limits adversely affects the lifespan of distribution equipment and can cause immediate equipment failure.

In undertaking feeder planning and operations, Toronto Hydro considers the system impact of the generator being online versus offline. The aforementioned thermal ratings affect the variability of various generation sources, system load growth, and the occurrence of contingencies. The ability to provide monitoring and control allows Toronto Hydro to monitor and mitigate feeder thermal loading. More detailed information is provided in Section E5.5.

E3.3.3 Planned Investments to Eliminate Constraints

In order to connect the forecasted amount of DG to Toronto Hydro's distribution system, the following solutions have been identified for the 2020 to 2024 period:

1) A bus-tie reactor is expected to increase DG connection capacity by lowering the short circuit current on the station bus and distribution system. Based on forecasted DG growth outlined in section E3.2, Toronto Hydro anticipates that five bus-tie reactors will be required over the 2020 to 2024 period to alleviate short circuit capacity constraints. The station buses where bus tie reactors are proposed are shown in the table below.

[2] IEEE 1547 Standard for Interconnecting Distributed Resources ("DR") with Electric Power Systems, section 4.4.1,

Table 1: Locations of Proposed Bus Tie Reactors (2020-2024)

Station	Bus	DG Connections as of end of 2017		Forecasted DG Connections by 2024	
		Total Capacity (MW)	Available Short Circuit Capacity (MVA)	Total Capacity (MW)	Available Short Circuit Capacity (MVA) without Bus-Tie Reactors
Ellesmere TS	*J*	7.9	49.6	12.47	-0.5
Esplanade TS	*A1A2*	7.3	57.6	17.88	-29.6
Fairbank TS	*YZ*	2.7	6.0	7.92	-10.6
Horner TS	*BY*	14.55	92.8	20.82	-4.6
Sheppard TS	*BY*	3.54	21.7	9.39	-4.0

As shown in the table above, as of the end of 2017, the five station buses have available short circuit capacity to connect DG. Based on the forecast methodology outlined in section E3.2, the total DG capacity expected to be connect by 2024 to each station bus (assuming no constraints) is also shown in the table. The connection of all the forecasted DG's would result in these five buses exceeding their short circuit limits by the amount shown in the final column.

1) Real-time monitoring and control are expected to allow Toronto Hydro to connect the forecasted amount of DG sources, and continue to meet the mandated requirements of the Distribution System Code.
2) Energy storage is expected to support network operation, by absorbing energy in off-load hours and supplying a certain amount of energy during peak periods to mitigate generation to load ratio concerns. The benefit is an improvement of voltage profiles, reduction in substation transformers and line overloading, reduction in system losses, and increase in network REG hosting capacity.

   Based on forecasted DG growth outlined in section E3.2, Toronto Hydro intends to install three energy storage systems over the 2020 to 2024 period to alleviate generation to load ratio concerns for three feeders, as outlined in the table below.

Table 2: Proposed Energy Storage Systems (2020-2024)

No.	Feeder	Station	Bus	Gen to Min Load Ratio	ESS (MW)	ESS (MWh)	ESS Cost ($M)
1	***51-M25***	*Leslie TS*	J	0.38	0.35	1.40	$1
2	***51-M32***	*Leslie TS*	Q	0.46	0.87	3.50	$2
3	***80-M27***	*Fairchild TS*	J	0.51	1.08	4.30	$2
Total					**2.30**	**9.20**	**$5.0**

By implementing these solutions, Toronto Hydro expects to be able to provide access across the distribution system, allowing REG source to connect on a grid-wide basis. In addition, Toronto Hydro forecasts that these investments will permit the distribution system to accommodate the total forecasted 800 MW of DG by the end of 2024. For more detailed information regarding the Generation Protection, Monitoring, and Control program, please refer to Exhibit 2B, Section E5.5.

E4 Capital Expenditure Summary

This section provides a 10-year view of Toronto Hydro's capital spending and System O&M for the 2015-2024 period, including explanatory notes on: (i) plan versus actual variances and trends during the historical period (i.e. 2015-2019), and (ii) shifts in forecast versus historical expenditures by investment category. The explanations in this section are focused on investment category level (and total) variances as presented in OEB Appendix 2-AB.[1] Toronto Hydro has also completed OEB Appendix 2-AA, which includes a 10-year view of expenditures across the utility's various capital programs.[2] Explanations for material variances and trends at the program level are provided within the "Expenditure Plan" section of each capital program narrative in sections E5 through E8.

E4.1 Plan versus Actual Variances for 2015-2019

In Toronto Hydro's 2015-2019 Custom IR Application, the OEB approved the utility's custom rate-setting mechanism and a resulting capital related revenue requirement of $2,497.9 million during the 2015-2019 period. As discussed in the Deferral and Variance Accounts exhibit, Toronto Hydro's actual capital spending is slightly less than approved for the period, resulting in a refund to customers of $59.4 million through the CRRR Variance Account.[3]

The OEB's envelope approval of CRRR for the 2015-2019 period did not include prescribed adjustments to the expenditure plans within specific programs or investment categories. Toronto Hydro received final rates in the first quarter of 2016 and proceeded to manage spending through the normal course of business planning and execution during the remaining years of the plan. This has included reprioritizing projects and adjusting program pacing where needed in order to: (i) remain within the OEB's approved CRRR, (ii) deliver on the highest priority objectives of the original 2015-2019 DSP,[4] and (iii) adapt to the typical variances and evolving circumstances that arise during the planning and execution of a large capital program.[5]

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[1] Exhibit 2A, Tab 4, Schedule 3
[2] Exhibit 2A, Tab 4, Schedule 2
[3] See Exhibit 9, Tab 1, Schedule 1 for more information.
[4] Some of the highest priority objectives for the 2015-2019 DSP included reducing the backlog of aging assets, improving reliability, reducing the number of high-risk legacy assets, reducing capacity constraints, and executing the Operating Centres Consolidation Program. Toronto Hydro's measured performance during 2015-2017 – including reliability performance – is discussed in in Section 1B, Tab 2, and in Section C of the DSP. Section E2 includes information on how historical performance influenced the 2020-2024 plan, and the narratives in Sections E5 through E8 discuss historical accomplishments relative to the 2015-2019 plan at the program level.
[5] Examples include: weather, feeder availability, permitting timing, and restrictions, etc.

In Table 1 below, Appendix 2-AB, and throughout the remainder of this section, Toronto Hydro refers to its filed 2015-2019 DSP as the "Plan" for 2015-2019. By comparing the 2015-2019 DSP to the actual and bridge year expenditures, the utility is able to provide a meaningful and complete picture of where adjustments were made through normal course planning to manage within approved rates, respond to evolving system and customer needs, and adapt to work program execution restrictions such as weather.

Toronto Hydro forecasts $2,383.5 million in actual capital expenditures over the 2015-2019 period, which is 4 percent lower than the $2,489.3 million forecasted in the 2015-2019 DSP. The breakdown of plan versus actuals by year and by category is presented in Table 1 below, and explanations for each category are provided in the following subsections.

Table 1: Historical Capital Expenditure Summary ($ Millions)

Category	Historical									Bridge					
	2015			2016			2017			2018			2019		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	For.	Var.	Plan	For.	Var.
System Access	86.1	58.3	(32%)	95.3	79.0	(17%)	104.9	65.5	(38%)	95.8	100.8	5%	92.3	97.1	5%
System Renewal	251.7	304.1	21%	239.6	266.1	11%	256.2	250.3	(2%)	275.9	229.4	(17%)	287.3	253.4	(12%)
System Service	76.5	37.9	(50%)	70.7	53.3	(25%)	65.1	72.4	11%	52.6	41.4	(21%)	80.2	41.8	(48%)
General Plant	104.6	79.4	(24%)	101.5	109.5	8%	30.3	98.9	226%	34.2	70.0	105%	30.3	40.2	33%
Other	12.2	11.6	(5%)	11.6	3.7	(68%)	10.8	10.7	(1%)	11.5	6.3	(46%)	12.1	2.4	(80%)
Total CAPEX	**531.1**	**491.4**	**(7%)**	**518.8**	**511.6**	**(1%)**	**467.4**	**497.8**	**7%**	**470.0**	**447.8**	**(5%)**	**502.2**	**434.9**	**(3%)**
System O&M	128.8	116.1	(10%)	126.5			126.3			126.9			131.0		

E4.1.1 2015-2019 Variances: System Access

As shown in Table 1, above, actual System Access expenditures were lower than forecast in each of 2015, 2016, and 2017, and are forecasted to be 16 percent lower than forecast for the five year period 2015 through 2019. The 2015 through 2017 variances were primarily driven by the following factors:

- Major projects with significant construction activities planned for the 2015-2019 period such as Metrolinx Eglinton Crosstown Light Rail Transit ("ECLRT"), Finch West Light Rail Transit ("FWLRT"), and Sheppard East Light Rail Transit ("SELRT"), and Union Pearson GO transit were delayed largely due to third party planning changes, resulting in lower than forecast costs in the first three years of the plan period. See Section E5.2 (Externally Initiated Plant Relocations and Expansion) for more details.

- A subset of generation protection and control projects did not proceed due to a number of technical and customer-related factors. For example, advancement of a Hydro One station upgrade project made it unnecessary to invest in short-circuit capacity constraints at that location, and shifts in the type of inverter technology favored by generation customers forced the utility to seek alternative solutions for relieving short-circuit constraints at Leslie TS. Additionally, delays in the procurement of monitoring and control systems deferred $1.8 million of work from the 2015-2019 period into the 2020-2024 period in the Generation Protection, Monitoring and Control ("GPMC") program. See Section E5.5 for more details.
- The Customer Connections program (Section E5.1) was materially less than forecast. This is a highly volatile program driven by various external factors (e.g. size and location or connections, available capacity provisions, economic drivers). Higher than anticipated capital contributions were a significant contributor to the lower than forecast net expenditures in this program. Toronto Hydro has adjusted its 2020-2024 forecasts to reflect this trend. See the Customer Connections narrative for additional details.

As discussed in each of the program justifications in Section E5, Toronto Hydro has taken the experience of the 2015-2019 period into account in developing the forecasts for the 2020-2024 period.

E4.1.1.1 2015-2019 Variances: System Renewal

As shown in Table 1, above, actual System Renewal expenditures were higher than forecast in each of 2015 and 2016, lower than forecast in 2017, and, overall, are projected to be in line with the forecast for the five year period 2015 through 2019. The 2015 through 2019 variances were primarily driven by the following factors:

- During 2015 and 2016, Toronto Hydro experienced a higher amount of Overhead System Renewal work (see Section E6.5) driven by declining reliability in 2013 and 2014; a higher amount of Underground System Renewal work (see Section E6.2) driven by improved inspection data, which identified an urgent need to address submersible transformers at risk of spilling oil contaminated with PCB; and higher than forecast Reactive Capital expenditures.

- In light of higher than forecast spending in 2015 and 2016, Toronto Hydro reduced forecast spending in 2017, 2018, and 2019 to remain in alignment with the utility's original five-year forecast for System Renewal.

As discussed in each of the program justifications in Section E6, Toronto Hydro has taken the experience of the 2015-2019 period into account in developing the forecasts for the 2020-2024 period.

E4.1.2 2015-2019 Variances: System Service

As shown in Table 1, above, actual System Service expenditures were lower than forecast in 2015 and 2016, higher than forecast in 2017, and are expected to be lower than forecast in 2018 and 2019. Overall, spending in the System Service category is expected to be 28 percent lower than forecast during the 2015-2019 period. The 2015 through 2019 variances were primarily driven by the following factors:

- Over the 2015-2019 period, Toronto Hydro reduced the pace of Feeder Automation and Contingency Enhancement investments. Both of these programs were developed to add remote switching capabilities and tie points in the Horseshoe area of the system, with the Feeder Automation program adding incremental capabilities by creating automated (i.e. "self-healing") switching schemes to improve outage restoration time. As discussed in Section E7.1 (System Enhancements), Toronto Hydro encountered operational limitations in its efforts to scale-up its use of peer-to-peer Feeder Automation technology. This led the utility to alter its approach to Feeder Automation, with a plan to explore a potentially more feasible centralized communications solution that leverages basic SCADA-enabled remote switching technology in combination with the utility's planned Network Management System ("NMS") upgrades. As a result of this decision, the utility significantly curtailed investment in the Feeder Automation program during the 2015-2019 period, and intends to develop the alternative solution during the 2020-2024 period. Toronto Hydro also scaled down its Contingency Enhancement program during the 2015-2019 period. Some of the highest priority work from this program was bundled with overhead rebuild work in the System Renewal category in order to deliver sustainable reliability benefits in poor performing areas.
- Lower than forecast spending in 2015 and 2016 was also related to delayed investments in the Stations Expansion program. The Copeland TS – Phase 1 project, a large and complex

project of unprecedented scale for Toronto Hydro, experienced slower progress and less spending than planned in 2015 and 2016 due to several unforeseen events and factors. The project is now scheduled for completion in 2018. Overall, Toronto Hydro is forecasting that Stations Expansion expenditures will be approximately 6 percent lower than forecast for the 2015-2019 period. Section E7.4 provides additional information on Copeland TS and other cost and timing variances for Stations Expansion work, including variances related to Toronto Hydro's capital contributions to Hydro One for transformer station upgrades.

E4.1.3 2015-2019 Variances: General Plant

As shown in Table 1, General Plant expenditures were lower than forecast in 2015 and higher than forecast in 2016 and 2017. Toronto Hydro expects expenditures to be greater than forecast in 2018 and 2019. Overall, 2015-2019 General Plant expenditures are projected to be 32 percent higher than forecast. Variances related to two major projects – the Operating Center Consolidation Program ("OCCP") and the Enterprise Resource Planning ("ERP") system – accounted for the majority of the variance between actual and planned spending:

- The OCCP was a real estate initiative from 2014 to 2018, intended to: (i) ensure security of tenure at major crew-supporting operating centers; (ii) ensure the uninterrupted continuation of critical functions; and (iii) achieve permanent significant cost savings for ratepayers. The OCCP program exceeded planned costs by $46.5 million due to higher than forecast capital improvement costs at 715 Milner Rd., 71 Rexdale Blvd., and 500 Commissioners St. These improvements were necessary to support consolidation. Changes in capital improvement costs were largely driven by changes in project costs between the initial and final estimates, including increases associated with the Ontario Building Code, environmental considerations, and design considerations.

  Despite these variances, the program has generated more value in returns to rate payers than originally planned. Table 2 shows the variances on cost and net gains of sale related to the original OCCP scope of work. Net proceeds from the sale of 5800 Yonge Street will be returned to rate payers in the form of a rider over the 2020-2024 period.[6]

[6] Refer to Exhibit 9, Tab 1, Schedule 1 for more information on the OCCP deferral and variance account.

Table 2: Costs and Gains Associated with the OCCP Program ($ Millions)

	Planned	Actual	Variance
Capital Cost	160.0	206.6	**46.6**
Net gain from Sale	72.5	142.2	**69.7**

/C

Beyond the original planned scope of consolidation, the program's space utilization efforts allowed Toronto Hydro to dispose of an additional property, at 60 Eglinton Ave., the proceeds of which will also be returned to ratepayers in the form of a rider over the 2020-2024 period. The employees from 60 Eglinton Ave. were transferred to other Toronto Hydro owned properties in June 2017, allowing for a reduction in maintenance costs related to that property. Overall, the program has achieved an increase of $69.8 million in amounts to be returned to rate payers compared to the original plan.

- IT/OT program investments are expected to exceed planned investments over the 2015-2019 period. Actuals in 2017 and forecasts in 2018 and 2019 are offset by lower than planned expenditures in 2015 and 2016, resulting in an expected variance over the 2015-2019 period of $18.3 million, or 9 percent.

  The majority of this variance is attributed to increased investment in Toronto Hydro's new ERP system, which the utility plans to complete in 2018. Approximately half of the ERP variance is attributed to higher infrastructure costs compared to the original high-level estimates developed in 2013. Drivers of cost changes included changes in the Canadian to American dollar exchange rate, a change in hardware requirements necessitated by standards changes during the period between the initial project estimate and the commencement of the project, additional requirements for components not identified in the 2013 estimate, and scope changes to include additional subscriptions and licenses for capabilities that would deliver greater benefits and better align with business requirements. The remaining variance is the result of a greater allocation of internal employee time in support of the project.

E4.1.4 2015-2019 Variances: Other Capital

Expenditures in the "Other Capital" investment category are projected to be 40 percent less than forecast over the 2015-2019 period. The Other Capital budget had included approximately $20.6 million in road cut repair costs. Toronto Hydro revised its approach during the period to begin recording actual road cut expenditures against specific projects, resulting in the negative variance shown in Table 1. The utility has carried this approach forward by including road cut repair costs within the capital program forecasts for 2020-2024.

E4.1.5 2015-2019 Variances: System O&M

System Operating and Maintenance ("System O&M") spending is driven by the need to maintain distribution assets and support the execution of Toronto Hydro's capital, maintenance, system response, and customer-driven work activities. The O&M expenditures for this category include the following activities, which are described in detail in Exhibit 4A, Tab 2:

- Supply Chain;
- Asset and Program Management;
- Work Program Execution;
- Customer-Driven Work;
- Control Centre Operations;
- Distribution Maintenance Programs;
- Emergency Response; and
- Fleet and Equipment Services.

As shown in Table 1, the utility's System O&M activities were lowest in 2015. Expenditures increased in 2016 to levels comparable with the originally forecast 2015 levels. Using actual 2015 spending as the comparison point, System OM&A is forecast to increase an average of 3 percent annually over the 2015-2019 period. However, relative to Toronto Hydro's planned 2015 System O&M, expenditures have remained essentially flat.

Fluctuations in costs associated with the business functions included in System O&M occur from year to year for many reasons. Reasons include:

- The volume of maintenance for an asset class is dictated by asset class maintenance cycles and varies from year-to-year.
- The extent of maintenance required for inspected assets can vary from year-to-year depending on observed condition and other factors.
- Costs associated with Emergency Response and Customer-Driven Work are subject to various external factors including weather and customer demand.

In light of the above drivers of variance, adjustments are made in program activities over the course of each year to manage cost increases in one function with deferral of activities and associated costs in other functions where appropriate. For example, costs associated with an increase in station battery failure for a particular year may be offset by a temporary reduction in the number of insulators requiring washing in that year.

In addition to the above noted drivers, capital investment can drive fluctuations in costs for associated planned, predictive, and corrective maintenance activities.

E4.1.5.1 Capital Investment and Planned Maintenance

As discussed in Section D3.1.1.3, the directional relationship between asset replacement and planned maintenance is largely dependent on the maintenance requirements for the assets being removed and installed. Certain types of System Renewal investment can reduce planned maintenance costs in specific circumstances. Generally, the removal of legacy and functionally obsolete assets from the system can eliminate the need for maintenance activities or higher maintenance frequencies that are specific to the legacy asset type. At the same time, new equipment and new standards and practices may introduce incremental maintenance requirements. A reduction in renewal spending can lead to asset deterioration, potentially resulting in the need for additional inspection cycles and associated maintenance. The corollary is also possible. The utility considers maintenance requirements when evaluating new products and developing new standards as part of its continuous Standards and Practices Review activities.

Compared to 2015 actuals, the Preventative and Predictive Maintenance components of System O&M are forecast to have increased by an average of 3 percent per year by 2019. However, a major driver of this increase is the introduction of a preventative Contact Voltage inspection program. When the total is normalized for this inspection program, Preventative and Predictive Maintenance expenditures have increased at 2 percent per year, roughly in line with inflation.[7]

[7] For more information on the Preventative and Predictive Maintenance programs, refer to Exhibit 4A, Tab 2, Schedules 1-3.

E4.1.5.2 Capital Investment and Corrective Maintenance

Corrective Maintenance can also fluctuate in response to capital work. A reduction in renewal spending can lead to asset deterioration, potentially resulting in an increase in corrective maintenance to mitigate increases in failure rates. The corollary is also possible.

As noted in Section D3.1.1.3, due to the overall age and condition of the system, the remaining volume of obsolete legacy assets, and increasing pressure from adverse weather events, Toronto Hydro does not anticipate an overall decline in planned, corrective, or emergency maintenance spending during the 2020-2024 period.

E4.2 Forecast (2020-2024) vs. Historical (2015-2019) Expenditures

E4.2.1 System Access: Historical vs. Forecast Expenditures

Table 3: System Access: 2015-2024 Expenditures ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
System Access	58.3	79.0	65.5	100.8	97.1	91.8	93.3	93.9	106.0	116.4

Toronto Hydro expects System Access expenditures will be generally stable from 2018 through 2024, with an increase in spending in 2020-2024 relative to the 2015-2019 period. As discussed in Section E2.2, this overall increase is primarily driven by continued growth in customer connections demand, greater certainty around major externally initiated relocations projects, and, beginning in 2022, the need to renew the utility's end-of-life Residential and Small C&I meters. Forecast inflation for construction costs is also a driver of increases in certain programs in this category. For more information on the programs in this category, refer to Section E5.

E4.2.2 System Renewal: Historical vs. Forecast Expenditures

Table 4: System Renewal Expenditures: 2015-2024 ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
System Renewal	304.1	266.1	250.3	229.4	253.4	306.6	325.7	323.1	339.0	325.5

System Renewal investments are forecast to be relatively stable over the 2020-2024 period at around $325 million per year, an increase over 2015-2019 spending levels. As discussed in Section E2.2, this increase is necessary to manage significant safety, reliability, and environmental asset risks and to ensure stable and predictable performance for current and future customers. There are multiple drivers of the overall increase in investment in 2020-2024, including, for example: wood pole condition demographics; a large population of overhead and underground transformers at risk of spilling oil contaminated with PCB; continuing needs related to high-risk legacy assets such as direct-buried cable and box construction; emerging needs in the downtown core, including replacement of high-risk lead cable; the need to address a growing backlog of critical stations-level equipment at risk of failure; increasing performance pressure on the system from climate change, necessitating greater investment in resiliency; projected increases in the amount reactive capital work; and anticipated cost pressures from construction inflation in the City of Toronto. These and other drivers are discussed in detail in Sections D1, E2, and throughout the System Renewal programs in Section E6.

A number of System Renewal programs included in the 2015-2019 plan are expected to be largely or entirely complete before 2020-2024, including:

- **Paper-Insulated Lead-Covered Leakers and Cable ("PILC") Piece-Outs:** This program will be completed during the 2015-2019 period. This is a targeted program to replace and repair leaking PILC cables and piece-out any cable in congested chambers to manage failure risk and mitigate safety hazards. All known high risk PILC leakers and piece-outs will be completed in the 2015-2019 period resulting in approximately 16 kilometres of PILC cable being addressed. If additional leaker locations are identified, they will either be repaired as part of the Reactive and Corrective Capital program or replaced through the new lead cable replacement segment in the Underground System Renewal – Downtown program (E6.3).
- **Underground Legacy Infrastructure**: The high-risk legacy equipment issues in this program will largely be addressed during the 2015-2019 period. Remaining transclosure units and cable chamber lids at risk of failure will be addressed within the Underground System Renewal Programs (E6.2 and E6.3) as noted below. By 2019, Toronto Hydro anticipates having successfully reduced significant safety and reliability risks on the underground system by addressing the following units 2015-2019:
    - 48 Sachsenwerk switch and fuse units;
    - 66 transclosures;
    - 10 Powerlite switches;

- 7 vault step transformers;
- 1,500 cable chamber covers; and
- Conversion of the legacy system configuration in Thorncliffe Park area.

- **Overhead Infrastructure Relocation**: This program focused on relocating overhead assets in areas with limited or difficult access, station egress assets carrying three or more circuits, and assets crossing highways. The relocation of these assets, improves employee safety and reliability to the distribution system by minimizing duration of interruptions due to accessibility issues. The most inaccessible and high-risk sites are forecast to be completed over the 2015-2019 period. As other inaccessible locations are identified that require relocation, they will be considered for relocation as part of the Overhead System Renewal program (E6.5) in 2020-2024, provided that their condition warrants their replacement.
- **SCADA-Mate R1 Switch Renewal**: All known SCADA-Mate R1 switches – which have numerous safety, reliability and operational concerns – will be replaced in the 2015-2019 period in order to eliminate the defective switches from the system. If additional SCADA-Mate R1 switches are identified, these will be addressed reactively or through renewal work in the Overhead System Renewal program.

E4.2.3 System Service: Historical vs. Forecast Expenditures

Table 5: System Service Expenditures: 2015-2024 ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
System Service	37.9	53.3	72.4	41.4	41.8	34.2	60.1	71.3	33.6	38.5

Overall, System Service investments in 2020-2024 are forecast to be slightly reduced compared to 2015-2019 spending. Reduced expenditures are largely driven by lower forecasted capacity expansion needs in the Stations Expansion program (E7.4) and a deliberately restrained pace of System Enhancement program (E7.1) expenditures, as well as the completion of a number of smaller System Service programs. These program reductions have been partially offset by the introduction of the Network Condition Monitoring and Control program, which aims to modernize the network system with the objective of mitigating safety, reliability and environmental risks and reducing other operational limitations. For additional details on these programs, refer to Section E7.

System Service investments are forecast to increase from 2020 to 2022 and then return to a 2020 spending level in 2023 and 2024. This reflects the pattern of spending in the Energy Storage Systems and Station Expansions programs, while System Enhancements expenditures are forecast to remain relatively stable and Network Condition Monitoring and Control expenditures to steadily increase from 2020 to 2024.

A number of System Service programs included in the 2015-2019 plan are expected to be largely or entirely complete before 2020-2024, including:

- **Design Enhancements:** Moving forward, to improve planning and execution efficiency, Toronto Hydro will include design enhancements such as tree-proof conductor upgrades in planned System Renewal programs or in the Worst Performing Feeder segment (E6.7) for the 2020-2024 period.
- **Overhead Momentary Reduction:** Toronto Hydro is conducting a pilot for Overhead Momentary Reduction study for this program during the 2015-2019 period. It involves the installation of reclosers and communication infrastructure to minimize momentary interruptions to customers. Toronto Hydro plans to install four reclosers on the system in 2019. Toronto Hydro will assess technical issues of implementation such as relay coordination as well as practical benefits to reliability prior to determining the feasibility and benefits of this program.
- **Handwell Upgrades**: Toronto Hydro's replacement of deteriorated and high-risk handwells is on track for completion in the 2015-2019 period. This program involved replacing legacy handwells with non-conductive material as well as renewing the secondary cables between handwells. Due to the safety issue related to the legacy handwell units, Toronto Hydro has upgraded all known locations to the non-conductive type handwells. These upgrades addressed safety issues associated with the risk of contact voltage from conductive handwells so that the risk to individuals, pets, and wildlife are minimized.
- **Polymer SMD-20 Switch Renewal**: Replacement of defective SMD-20 switches is on track for completion during the 2015-2019 period. This program replaces all identified polymer SMD-20 switches in the system with a newer fiberglass core model. Due to the safety risks associated with operating the switch, all locations will be replaced by 2019.
- **Downtown Contingency**: In 2015-2019, this program was planned to address station level contingency risk through the establishment of inter-station feeder ties. Toronto Hydro successfully completed a number of overheard feeder ties, but upon re-evaluating the costs

and challenges associated with underground feeder ties, decided to cancel the remaining underground work in the program. Note that the 2015-2019 spending for Downtown Contingency was included as part of System Enhancements spending in the Capital Projects Table OEB Appendix 2-AA (Exhibit 2A, Tab 4, Schedule 2).

- **Feeder Automation**: As noted in Section 4.1.3 above, Toronto Hydro has changed its approach on Feeder Automation to move away from a peer-to-peer (i.e. switch-to-switch) communication technology to a centralized solution leveraging the planned NMS upgrade. In light of this change, it is no longer necessary to separate the System Service activities that enable feeder automation (i.e. installing automated tie- and sectionalizing-points on feeders) from the Contingency Enhancement segment that is included as part of the System Enhancements program. (Previously, the key difference between Contingency Enhancement and Feeder Automation was the need to retrofit SCADA switches with peer-to-peer communications technology.) For more information on the Contingency Enhancement program for 2020-2024 and the accomplishments of the Feeder Automation program in 2015-2019, refer to the System Enhancements program at Section E7.1.

E4.2.4 General Plant: Historical vs. Forecast Expenditures

Table 6: General Plant Expenditures: 2015-2024 ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
General Plant	79.4	109.5	98.9	70.0	40.2	78.8	93.7	89.0	77.7	85.2

Over the 2020-2024 period, General Plant investments are forecast to be relatively stable with expenditures averaging approximately $85 million per year, a slight increase over 2015-2019 levels. As discussed in detail in Section E2.2, the moderate increase in this category is driven by the new, one-time Control Operations Reinforcement program and increases in spending for the Facilities Management and Security, Fleet and Equipment Services, and IT/OT Systems programs, which are driven primarily by asset lifecycle needs, IT investments to meet evolving customer service needs and preferences, and operational continuity risks. These increases are partially offset by the completion of the Operating Centers Consolidation Program and Program Support programs in 2015-2019. For further information on the 2020-2024 General Plant programs, refer to Section E8.

Two System Service programs included in the 2015-2019 plan are expected to be complete before 2020-2024:

- **Operating Centers Consolidation Program:** On track for completion in 2018. See section E4.2.4 above for more details.
- **Program Support**: Activities in this program will be completed by 2019. This program included climate change related activities (i.e. studies and pilots), the results of which are discussed in Section D2, and upgrades to Asset Management capabilities.

E4.2.5 Other Capital: Historical vs. Forecast Expenditures

Table 7: Other Capital Expenditures: 2015-2024 ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Other Capital	11.6	3.7	10.7	6.3	2.4	7.0	9.0	9.8	9.5	8.7

Toronto Hydro's forecast for Other Capital expenditures includes forecasted amounts for Allowance for Funds Used during Construction ("AFUDC") and routine costs related to the replacement of major tools used in the execution of capital and maintenance programs.

E4.2.6 System O&M: Historical vs. Forecast Expenditures

Table 8: System O&M Expenditures: 2015-2020 ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
System O&M	116.1	126.5	126.3	126.9	131.0	130.4				

Overall, System O&M expenditures are expected to remain essentially flat between 2017 and 2020, with an average annual increase of approximately 1 percent per year (and a lower budgeted amount in 2020 than in 2019). For details on the programs that constitute System O&M, refer to Exhibit 4A, Tab 2. These expenditures are the minimum necessary to meet the utility's various system-related outcome objectives during the 2020-2024 period.

E4.2.7 Trends in Category Spending – Historical vs. Forecast

Table 9 below shows the contribution to the total capital program of each investment category for the 2015-2019 and 2020-2024 periods. There are no marked changes in the share of total investment represented by a given investment category over the forecast period relative to the actual spending over the historical period. On a percentage basis, there is a slight shift away from General Plant and System Service investments to System Renewal and Access investments, reflecting the net result of various planning considerations and drivers, as discussed in Section E2 and in Sections E5 to E8.

Table 9: Historical and Forecast Share of Total by Investment Category

Category	Historical Share of Total (%)						Forecast Share of Total (%)					
	2015	2016	2017	2018	2019	Average	2020	2021	2022	2023	2024	Average
System Access	12%	15%	13%	23%	22%	**17%**	18%	16%	16%	19%	20%	**18%**
System Renewal	62%	52%	50%	51%	58%	**55%**	59%	56%	55%	60%	57%	**57%**
System Service	8%	10%	15%	9%	10%	**10%**	7%	10%	12%	6%	7%	**8%**
General Plant	16%	21%	20%	16%	9%	**17%**	15%	16%	15%	14%	15%	**15%**
Other CAPEX	2%	1%	2%	1%	1%	**1%**	1%	2%	2%	2%	2%	**2%**
Total	100%	100%	100%	100%	100%	**100%**	100%	100%	100%	100%	100%	**100%**

E5 System Access Investments

E5.1 Customer Connections

E5.2 Externally Initiated Plant Relocations and Expansion

E5.3 Load Demand

E5.4 Metering

E5.5 Generation Protection, Monitoring, and Control

E5.1 Customer Connections

E5.1.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 176.1	**2020-2024 Cost ($M):** 223.4
Segments: Load Connections; Generation Connections	
Trigger Driver: Customer Service Requests	
Outcomes: Customer Service, Public Policy, Safety, Reliability	

The Customer Connections program ("the Program") captures system investments that Toronto Hydro is required to make to provide customers with access to its distribution system. This includes enabling new or modified load and distributed generation ("DG") connections to the distribution system, in accordance with legal and regulatory obligations under various statutes and codes. This Program is a continuation of customer connection activities described in Toronto Hydro's 2015-2019 Distribution System Plan.[1]

Toronto Hydro's primary objective in this Program is to provide new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system. In pursuing this objective, the utility strives to meet, and where possible, exceed, all mandated service obligations. In 2017, Toronto Hydro completed 98.32 percent, and 98.41 percent, of low voltage (below 750 V) and high voltage (750 V or above) connections, respectively, as well as 92.41 percent of distributed generation connections on time.[2]

The Program is comprised of two segments:

- **Load Connections**: This segment involves completing new load connections and upgrades to existing load connections. Customers are connected to one of the various overhead or underground distribution systems in the City. The work also includes any expansion work necessary to address capacity constraints for the purpose of connecting customers.

[1] EB-2014-0116, Exhibit 2B, Section E5.2
[2] These metrics will be published in Toronto Hydro's 2017 Scorecard.

- **Generation Connections**: This segment involves connecting DG customers to the distribution system.

The investments made by Toronto Hydro in this Program support the ongoing economic growth and development in the City of Toronto.[3] The connection of DG facilities under this Program supports the achievement of public policy objectives with respect to the expansion of green energy alternatives and mitigation of climate change in alignment with the Long Term Energy Plan ("LTEP") and the directive issued by the Minister of Energy on April 5, 2016.[4]

E5.1.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro customer service objectives by: ○ Fulfilling customer service requests as mandated by Sections 6.2.4 (generation connections) and 7.2 (customer connections) of the Distribution System Code ("DSC"), *Electricity Act, 1998* (Electricity Act), and *Ontario Energy Board Act, 1998* (OEB Act); and Toronto Hydro's Conditions of Service and Electricity Distribution License; ○ Completing low and high voltage connections within 5 and 10 business days respectively at least 90 percent of the time, as measured pursuant to the OEB's new connection metrics and section 7.2 of the DSC; ○ Completing customer appointments in accordance with the OEB's Appointment Scheduling and Appointments Met metrics, 90 percent of the time, as per sections 7.3 and 7.4 of the DSC; and ○ Responding to inquiries requiring a written response within 10 business days at least 80 percent of the time, as measured pursuant to the OEB's Written Response metric and section 7.8 of the DSC. ○ Connecting DG facilities to the distribution system as mandated by sections 25.36, 25.37, and section 26 of the *Electricity Act,* 1998; and; without extensive delays or adverse impacts to existing customers, within 5 business days at least 90 percent of the time on a yearly basis as per section 6.2.7 of the DSC.

[3] Toronto Economic Bulletin, May 25, 2018, Available from: https://www.toronto.ca/wp-content/uploads/2018/05/95f7-EDC-Toronto-Economic-Bulletin-May-2018.pdf
[4] Ontario Ministry of Energy, Ministerial Directive - Future Renewable Energy Procurements, April 5, 2016.

Public Policy	• Supports the Ministerial renewable energy procurements directive[4] by connecting DG facilities that: o Reduce greenhouse gas emissions from fuel burning plants (renewable DG connections); and o Reduce "line losses" that occur during the transmission and distribution of electricity (renewable and non-renewable DG connections).
Safety	• Contributes to compliance with *Ontario Regulation 22/4* and safety objectives by: o Ensuring service connections are compliant with applicable requirements; and o Ensuring Electrical Safety Authority connection permits are available prior to connecting new or upgraded customers' service entrance equipment.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, System Capacity) by installing assets that meet up-to-date standards and provide sufficient capacity when completing the connection request.

E5.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Customer Service Requests
Secondary Driver(s)	Mandated Service Obligations

E5.1.3.1 Load Connections

The Load Connections segment is driven by customer requests to connect to Toronto Hydro's distribution system and service upgrades for existing customers. Continuing growth in residential and commercial developments within the City is a fundamental driver of the volume of work in the Load Connections segment, as many, if not all, new developments will require new or modified connections to Toronto Hydro's distribution system. Toronto Hydro anticipates that the number of customer service requests and the size of the requested connections will continue to trend up to accommodate growing residential and commercial needs. Toronto Hydro is required to fulfill these service connection requests or to make an offer to connect ("OTC") any customers in its service area and meet its legal obligation to connect these new and existing customers to its distribution system pursuant to its Conditions of Service and section 28 of the *Electricity Act*, subject to certain exemptions specified in the DSC.

Serving one of the fastest growing cities in North America, Toronto Hydro receives high volumes of requests for connections and upgrades for residential and commercial developments each year. The City of Toronto's current rate of development is expected to continue over the 2020-2024 period. From 2012 to 2016, the City's development pipeline included 2,523 projects in various stages of approval and completion[5] with 1,156 built, 743 active and 624 under review[6] as shown in Figure 1 below. Toronto Hydro anticipates that a large number of projects and proposed loads submitted between 2012 and 2016 as well as those submitted between 2017 and 2019 are expected to be completed within the 2020-2024 period or shortly thereafter based on the average completion rate and the number of units proposed for the City of Toronto.[7] The projects in the City's development pipeline will account for 363,859 residential units and 9.53 million m^2 of non-residential Gross Floor Area, which will require connections to Toronto Hydro's distribution system.

	Built	Active	Under Review	Total in Pipeline	% of Total
City of Toronto	**1,156**	**743**	**624**	**2,523**	
Growth Areas					
Downtown and Central Waterfront	**187**	**129**	**132**	**448**	**17.8**
Centres	**28**	**34**	**26**	**88**	**3.5**
Etobicoke Centre	6	10	3	19	21.6
North York Centre	14	9	9	32	36.4
Scarborough Centre	4	3	1	8	9.1
Yonge-Eglinton Centre	4	12	13	29	33.0
Avenues	**174**	**154**	**147**	**475**	**18.8**
Other Mixed Use Areas	**79**	**82**	**55**	**216**	**8.6**
All Other Areas	**688**	**344**	**264**	**1,296**	**51.4**

Source: City of Toronto, City Planning Division: Land Use Information System II

Development projects with activity between January 1, 2012 and December 31, 2016. Built projects are those which became ready for occupancy and/or were completed. Active projects are those which have been approved, for which building permits have been applied or have been issued, and/or those which are under construction. Projects under review are those which have not yet been approved or refused and those which are under appeal.

Figure 1: Proposed Projects in the City of Toronto (2012-2016)

This pace of development and growth is consistent with the City's projected growth in population, which is over 2.9 million as of July 2017[8] and is expected to reach 3.9 million by 2041.[9] The increase

5 Including projects that are pending approval, approved, awaiting or holding building permits, or under construction.
6 City of Toronto, "How Does The City Grow?" April 2017.
7 Discussed further in the Load Demand program, see Exhibit 2B, Schedule E5.3.
8 City of Toronto, "Toronto at a Glance" Available from: https://www.toronto.ca/city-government/data-research-maps/toronto-at-a-glance/
9 Ontario Ministry of Finance, Ontario Population Projections Update, 2016-2041 Available from: https://www.fin.gov.on.ca/en/economy/demographics/projections/

in population will require additional accommodation, commercial spaces and services.[10] This growth is also reinforced by the projected GDP growth anticipated for the City, which is expected to be around 2 percent per annum for the period of 2020-2024.

As illustrated in Figure 2, from 2007 to 2017, Toronto Hydro connected approximately 88,000 customers, representing a 13 percent increase in its customer base (average of 1.3 percent per year), and approximately 49,000 customers from 2012 to 2017, representing a 7 percent increase (average of 1.4 percent per year). Similar levels of growth are expected for the 2020-2024 period, as described in the Customer Forecast Section.[11] These additional customers were connected to Toronto Hydro's distribution system as a result of the investments in the Load Connection segment.

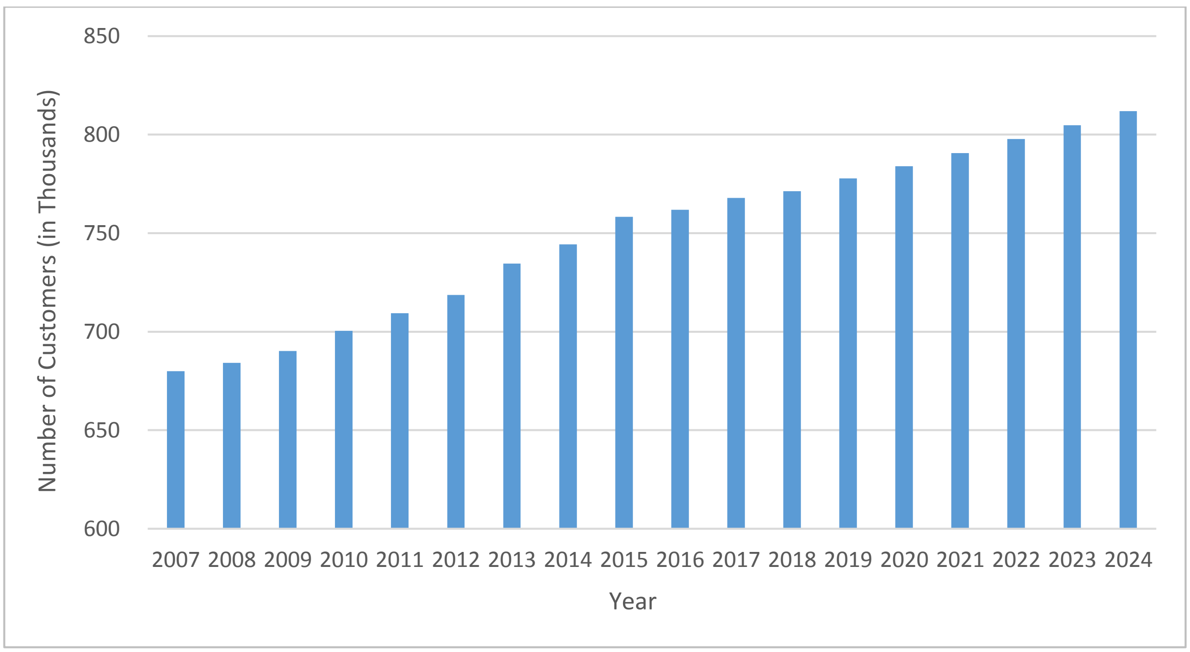

Figure 2: Historical and Forecast Number of Toronto Hydro Customers

Customer connections can be in the form of a basic connection, or a connection requiring expansion work. The types of connections Toronto Hydro performs can generally be divided into two categories as follows:

10 As of 2017, Toronto continues to lead in the number of major buildings under construction, ranking second in tall building construction after New York (Toronto Economic Bulletin, May 25, 2018).
11 Exhibit 3, Tab 1, Schedule 1.

- **Low voltage requests (below 750 Volts):** These requests primarily involve residential and small commercial customers (GS<50 rate class) supplied at 750 Volts or less whose average monthly maximum demand is less than, or is forecasted to be less than 50 kW. As shown in Figure 3, the volume of low voltage connections has been high in recent years (i.e. consistently exceeding 2,500 per year); however, the work is typically seasonal and has a relatively short turnaround time. As part of Toronto Hydro's obligations, the utility works with customers to provide options for a new connection or service upgrade. As per the DSC, section 7.2.1, these service requests must be completed within 5 business days from the day on which all applicable service conditions are satisfied, or at a later date as agreed to by the customer and distributor.

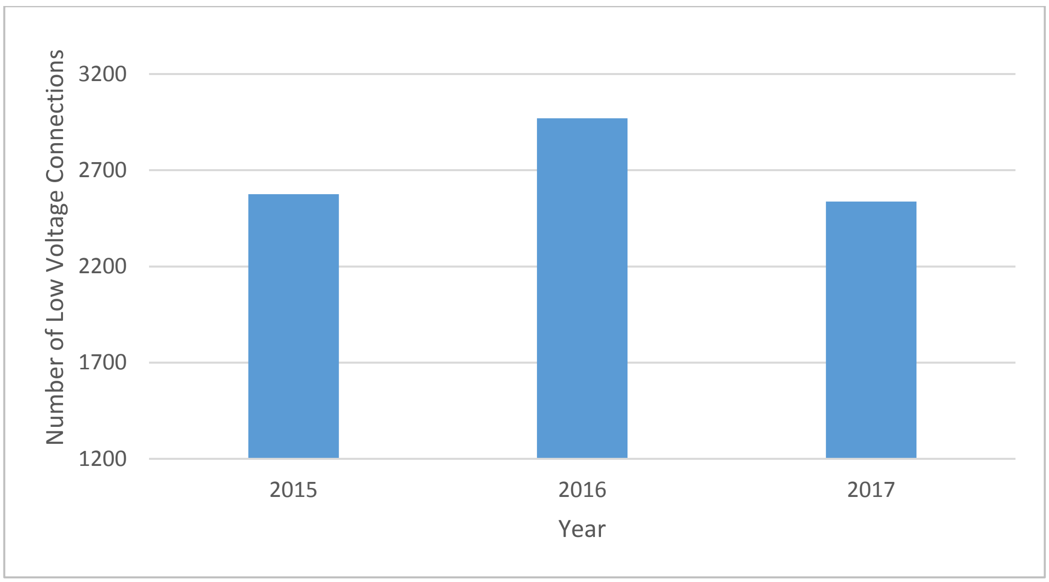

Figure 3: Low Voltage Connections 2015-2017

- **High voltage requests (750 Volts and above):** These requests primarily relate to larger residential and commercial developments. These customers typically engage Toronto Hydro years before service is expected to be required. Figure 4 provides a year-over-year comparison of the volume of new formalized high voltage requests that Toronto Hydro receives on an annual basis. As per section 7.2.2 of the DSC, these service requests must be completed within 10 business days from the day on which all applicable service conditions are satisfied, or at a later date as agreed to by the customer and distributor.

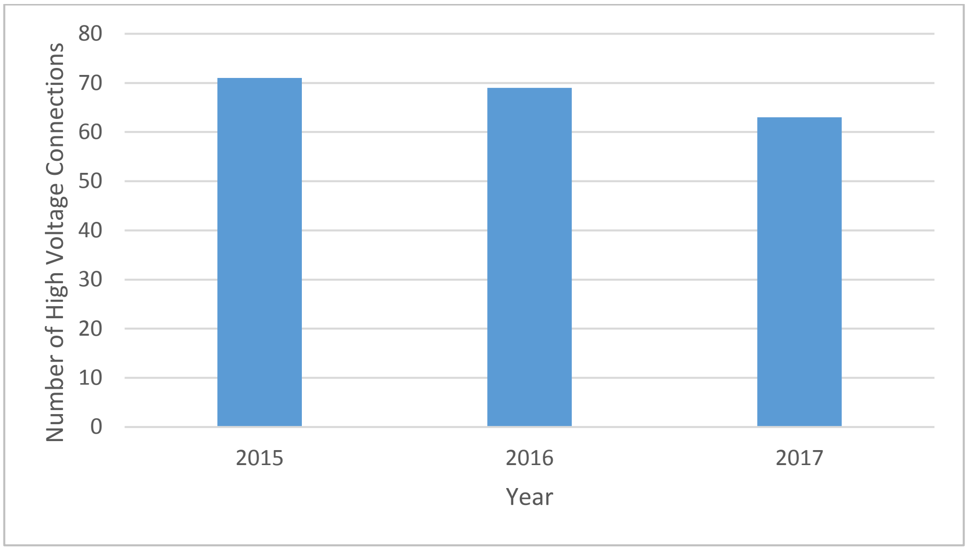

Figure 4: High Voltage Requests 2015-2017

For both low and high voltage service requests, applicable service quality requirement must be met at least 90 percent of the time on a yearly basis. Toronto Hydro processed a total of 1,901 feeder requests[12] over the last five years (i.e. between 2013 and 2017), including 948 (43 percent) during 2016 and 2017, as shown in Figure 5 below. Figure 6 illustrates the variation in location and load requirements for the requests. The overall increasing trend in the volume of requests processed from year to year is expected to continue up to and throughout the 2020-2024 period. Following a feeder request, the connection typically materializes within 5 years, from the day the feeder request was created, excluding any project delays. As a result, a number of feeder requests received between 2015 and 2019 are expected to drive work in the 2020-2024 period.

[12] **Feeder request**: An internal request to determine the appropriate point and method of connecting customers exceeding 50 kW to Toronto Hydro's distribution system. Feeder requests relate to both potential and proposed projects in their preliminary stages.

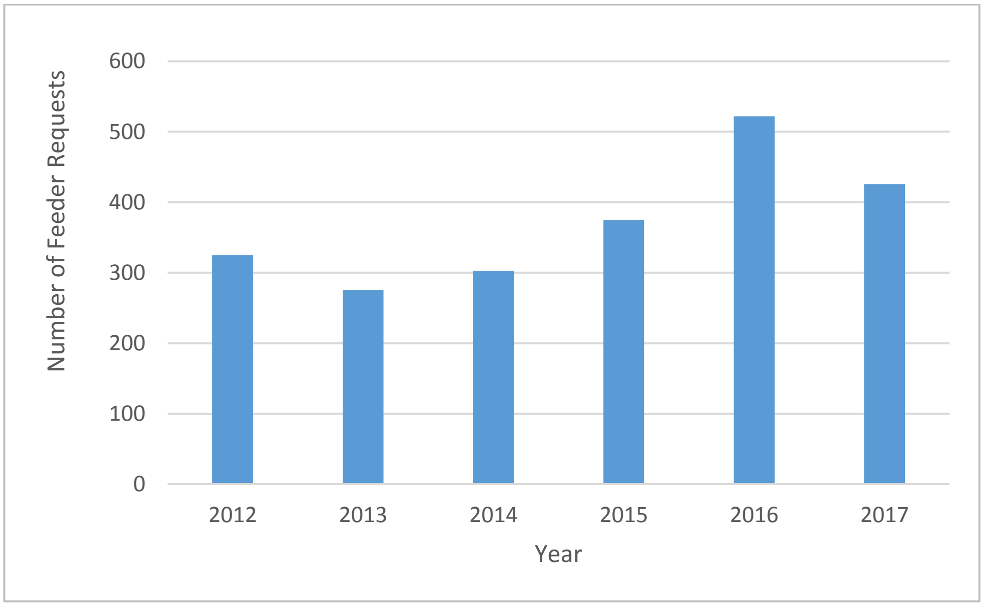

Figure 5: Feeder requests processed (2012-2017)

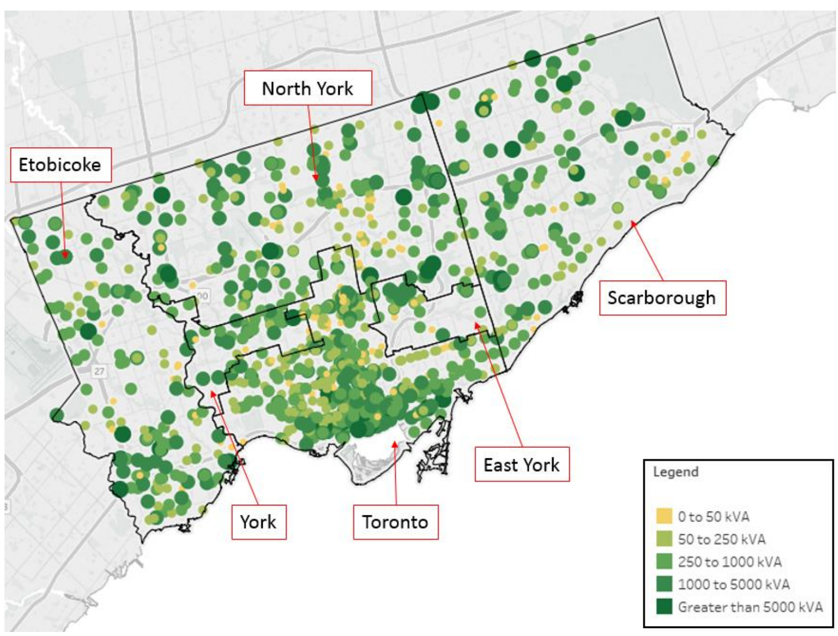

Figure 6: Proposed Load Additions in the City of Toronto during the 2012-2017 Period

Similar trends were observed in the overall increasing volumes of Offers to Connect (OTCs) issued requiring expansion work throughout the 2012-2017 period, as illustrated in Figure 7*.* Expansion work is typically needed for larger connections or requests in areas of the City that are capacity constrained. This involves the installation or upgrade of distribution assets such as new circuits or civil infrastructure required to accommodate new customer loading. Such work can have a significant cost impact as it typically requires a substantial amount of resources to plan and construct the infrastructure necessary to connect a large customer. The resulting expansion projects are usually large-scale and complex, and thus require weeks or months to complete. Connecting customers to the distribution system without completing the necessary expansions can negatively impact system reliability and safety.

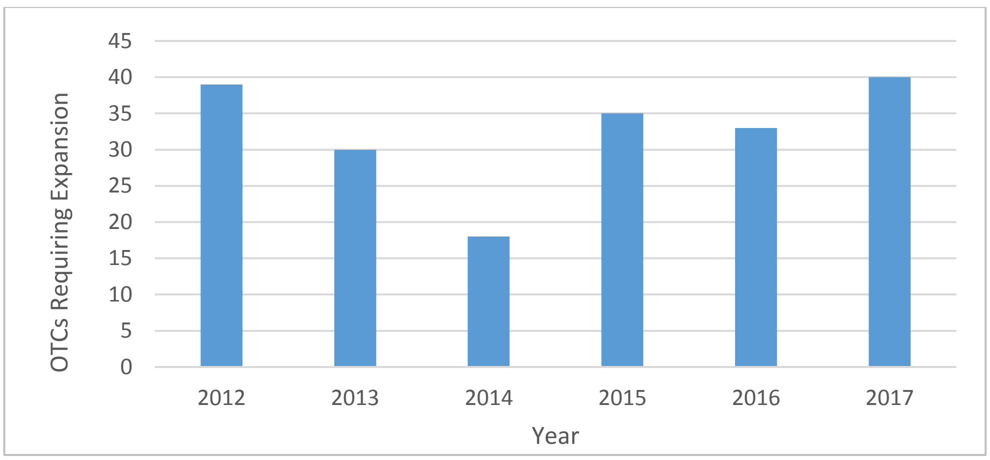

Figure 7: Offers to connect Requiring Expansion

E5.1.3.2 Generation Connections

As per Section 6.2.4 of the DSC, and sections 25.36 of the *Electricity Act*, Toronto Hydro is mandated to connect DG customers to its distribution system while maintaining the safety and reliability of the system for existing customers. Toronto Hydro is also obligated under section 6.1 of its Distribution License and section 26 of the *Electricity Act* to provide generators with non-discriminatory access to its distribution system and to provide priority access for renewable energy generation facilities. It is also required to meet certain timelines when connecting and assessing DG facilities:

- A distributor, as per DSC sections 6.2.7 and 6.2.7A, shall connect an applicant's micro-embedded generation facility to its distribution system within 5 business days from the day on which all applicable service conditions are satisfied, 90 percent of the time on a yearly basis, or at such later date as agreed to by the customer and distributor.
- Section 25.37 of the *Electricity Act* requires that Generation Connection Impact Assessments ("CIA") for renewable energy generation facilities be completed by electricity

distributors within prescribed timelines, and also requires distributors to report quarterly to the OEB on their ability to meet those timelines. Ontario Regulation 326/09 (Mandatory Information re Connections) sets out details regarding the timing of, and reporting on, connection assessments.

Toronto Hydro supports connecting DGs to the distribution system in alignment with the DSC and in coordination with Hydro One and the IESO. As of the end of 2017, Toronto Hydro had responded to over 8,000 inquiries from customers and developers seeking to connect generation under various programs such as the IESO programs,[13] Net-Metering, Energy Storage, Combined Heat and Power ("CHP"), Closed Transition and Load Displacement. A wide range of proponents have submitted project applications, including many schools, housing managers, large grocery stores, condominium corporations, and department stores. As of the end of 2017, Toronto Hydro had connected nearly 1,800 DGs of various sizes totalling 225.7 MW in capacity as seen in Table 4. An overview of the number and total capacity of DGs connected by technology types are provided in Table 4, Table 5 and Figure 8.

Table 4: Cumulative Existing Generation Connections

Generation Type	2010	2011	2012	2013	2014	2015	2016	2017
Renewable	216	407	584	785	978	1304	1554	1750
Natural Gas	18	18	19	20	20	22	22	26
Diesel	8	9	9	10	11	13	16	18
Energy Storage	0	0	0	1	1	2	3	3
Total	**242**	**434**	**612**	**816**	**1010**	**1341**	**1595**	**1797**

Table 5: Cumulative Existing Generation Capacity (in MW)

Generation Type	2010	2011	2012	2013	2014	2015	2016	2017
Renewable	6.7	12.8	21.3	30.9	44.5	71.9	86.6	96.6
Natural Gas	55.1	55.1	57.1	66.1	66.1	75.9	75.9	80.9
Diesel	11.8	13.3	13.3	14.5	19.5	29.6	36.1	47.1
Energy Storage	0.0	0.0	0.0	0.5	0.5	1.2	1.2	1.2
Total	**73.6**	**81.1**	**91.6**	**111.9**	**130.5**	**178.6**	**199.7**	**225.7**

[13] Including Feed-in-Tariff (FIT), microFIT, Process and Systems Upgrade Initiative (PSUI), and Renewable Energy Standard Offer Program (RESOP).

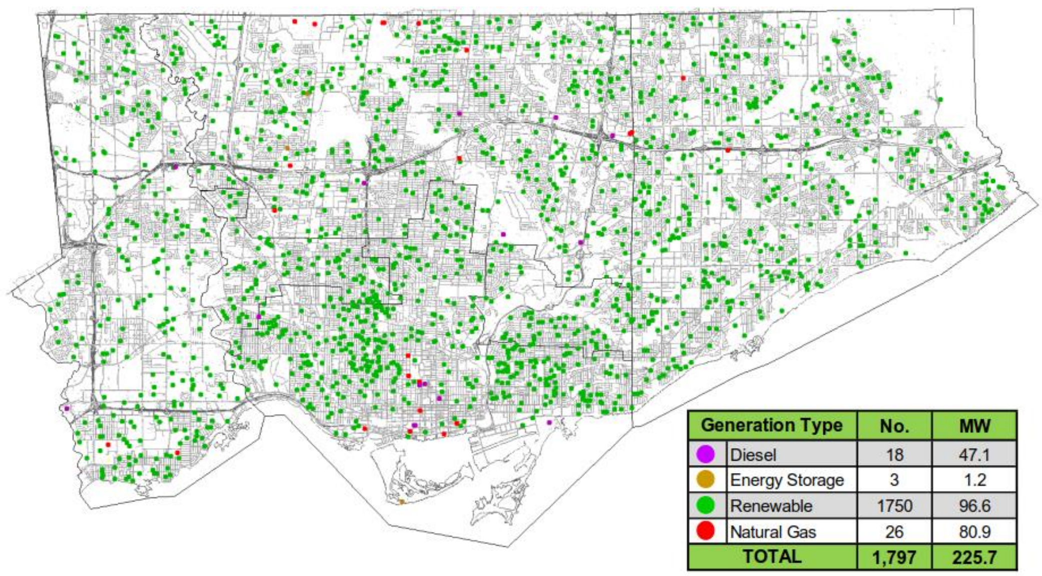

Figure 8: Generation Connections in Toronto Hydro Service Area by Generation Type

Customers have shown a steadily increasing interest in DG projects, as evidenced by the historical connection figures in Table 4 and Table 5 and by the large amount of inquiries received by Toronto Hydro in this regard. The majority of the applications received to date are for renewable generation projects under the FIT and microFIT programs. However, there is a growing interest in the Net-Metering program and battery Energy Storage, due to policy changes[14] in Ontario and as costs associated with solar photovoltaic panels, inverters and lithium-ion batteries continue to fall. Based on market projections, battery energy storage connections are expected to increase between 15 percent[15] and 25 percent[16] year-over-year as the technology matures and prices fall to economical levels.

Figure 9 shows the historical and forecasted DG capacity within Toronto Hydro's service territory up to 2024 (see section 4.2 for forecast details).

[14] See: LTEP and April 5, 2017 Ministerial Directive (*Supra* note 3)
[15] Based on observed trends since the 2015-2019 CIR application and the increased emergence of micro-turbine CHP in recent years.
[16] Navigant Research Report Findings in Hill, J.S. (2015). "Distributed Energy Storage Revenue to Exceed $16.5 Billion by 2024". *CleanTechnica.* Jan 13, 2015. Available from: https://cleantechnica.com/2015/01/13/grid-scale-energy-storage-expected-generate-68-billion-revenue-2014-2024-according-navigant-research/

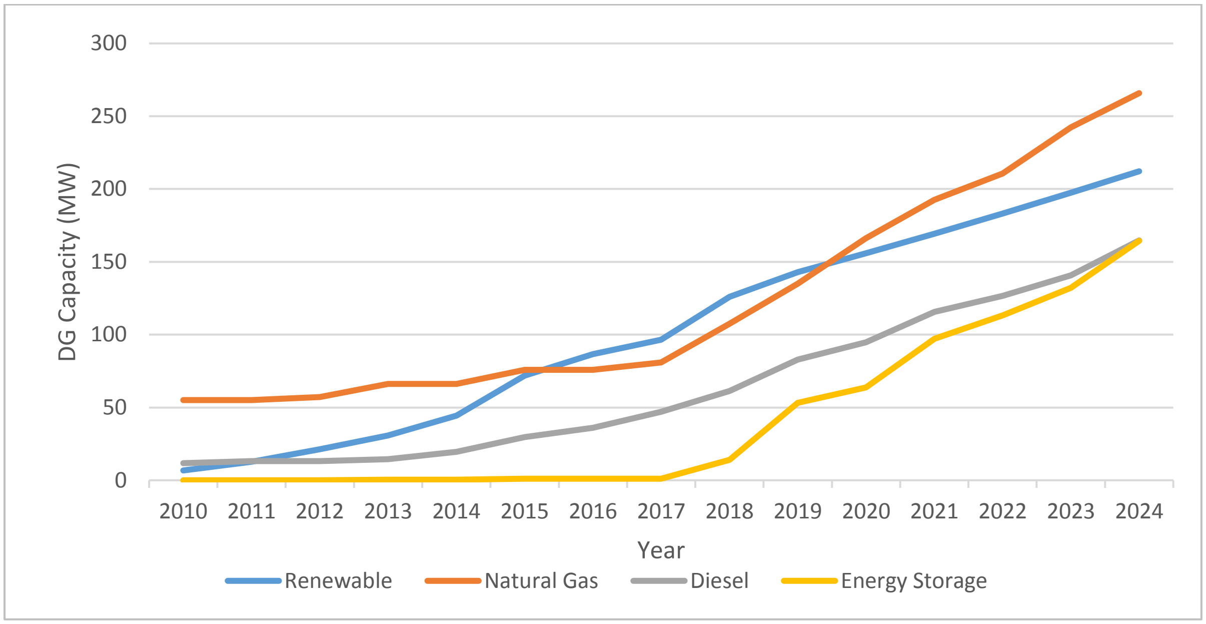

Figure 9: Forecast Generation Capacity

Toronto Hydro's DG connection forecast is based on historical DG connections, initial consultations and preliminary assessments received and completed from 2009 onwards, which include initial consultations regarding the Net-Metering, CHP, Closed Transition, Load-Displacement, IESO Energy Storage Procurement Request for Proposal ("RFP") and IESO programs such as PSUI and FIT[17]. The forecast takes into account the historical connection trends, completed assessments, and anticipated projects with respect to various DG programs.

Forecasts for DG connections and capacity are provided in Table 6 , Table 7 and Figure 9. DG projects are expected to nearly double by 2024, reaching approximately 3600 connections. This represents an additional 581 MW on top of the 225.7 MW of existing DG as of the end of 2017.

Table 6: Forecast Generation Connections (Volumes)

Generation Type	2018	2019	2020	2021	2022	2023	2024
Renewable	2074	2235	2390	2550	2715	2885	3062
Natural Gas	46	65	88	114	143	178	217
Diesel	21	27	33	40	46	54	63
Energy Storage	28	52	77	110	148	194	251
Total	**2169**	**2379**	**2588**	**2814**	**3052**	**3311**	**3593**

[17] *Supra* note 13

Table 7: Forecast Generation Capacity (in MW)

Generation Type	2018	2019	2020	2021	2022	2023	2024
Renewable	126.0	143.0	156.0	169.4	183.2	197.4	212.2
Natural Gas	107.5	135.1	166.3	192.7	210.7	242.3	265.9
Diesel	61.2	82.9	94.7	115.7	126.7	140.7	164.7
Energy Storage	14.0	53.2	63.7	97.1	113.2	132.2	164.4
Total	**308.7**	**414.3**	**480.7**	**574.8**	**633.8**	**712.6**	**807.2**

The above forecast is consistent with the current trend being observed in respect to DG connections. Customer interest in large, medium, and small-scale CHP generation facilities also continues to rise due to industrial and commercial customers seeking site reliability and operational cost savings. Inquiries for medium and large embedded CHP facilities have more than tripled from 15 in 2015 to almost 50 in 2017. Similarly, customer interest in small-scale microturbine-based CHP facilities[18] continues to rise as the number of connection requests has jumped from 25 in 2015 to 120 in 2017. Toronto Hydro anticipates a large volume of applications for these CHP facilities over the 2020-2024 period, as more customers become aware of this technology's economic benefits.

At this time, there are over 450 micro and small sized renewable projects totalling 31 MW that have been assessed and approved by Toronto Hydro for connection under the microFIT, FIT and Net-Metering programs. These projects are expected to be connected to the distribution system by the end of 2018.

Toronto Hydro is aware of 19 medium and large sized CHP, Diesel Closed Transition and Energy Storage projects totalling 124 MW in nameplate capacity. These projects are in various stages of development and will take longer to be connected to the distribution system (i.e. anticipated to be connected between 2018 and 2020) due to their larger size.

[18] This technology is ideally suited for small-scale power generation in multi-level residential buildings.

E5.1.4 Expenditure Plan

Table 8: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Customer Connection	32.6	39.6	22.1	44.8	37.6	42.9	43.9	44.8	45.6	46.3
Generation Connection	(0.9)	0.4	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**31.7**	**40.1**	**21.9**	**44.8**	**37.6**	**42.9**	**43.9**	**44.8**	**45.6**	**46.3**

E5.1.4.1 Customer Connections

Table 9: Historical & Forecast Program Costs ($ Millions)

		Actual			Bridge		Forecast				
		2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Customer Connection	*Gross*	68.3	67.1	58.6	82.1	78.6	73.6	75.3	76.9	78.2	79.6
	CC[A]	(35.7)	(27.4)	(36.5)	(37.2)	(41.0)	(30.8)	(31.4)	(32.0)	(32.7)	(33.3)
	Net	**32.6**	**39.6**	**22.1**	**44.8**	**37.6**	**42.9**	**43.9**	**44.8**	**45.6**	**46.3**

[A] CC: Customer Contributions

Expenditure in the Customer Connections segment is driven by a myriad of factors. Year to year variations are due to factors such as economic drivers and changes, the specific type of connection and associated expansion work, and provincial and municipal policies regarding infrastructure and community revitalization projects. As described below, Toronto Hydro's 2020-2024 expenditure forecast is based on historical data.

The irregular nature of expenditures in this segment is attributed to externally driven variables, which include:

1) Economic drivers, changes, and policies influence corporations from various industries (such as technology,[19] design,[20] food & beverage,[21] film, financial services, transportation, etc.) to operate or expand in Toronto, consequently impacting investment needs and expenditures.

[19] Toronto is North America's fastest growing technology market - https://www.toronto.ca/business-economy/industry-sector-support/
[20] Toronto employs the largest design workforce in Canada and third largest in North America - https://www.toronto.ca/business-economy/industry-sector-support/
[21] Toronto is a major decision-making centre for the food industry in Canada, with half of Canada's top ranked food and beverage manufacturers being headquartered in the city https://www.toronto.ca/business-economy/industry-sector-support/food-beverage/

2) Provincial and municipal policies regarding infrastructure and community revitalization projects (e.g. Six Points and Toronto Waterfront), hospitals, universities, public transit projects (e.g. TTC and Metrolinx) may give rise to connection work and consequently create further construction and related work in the relevant project sites and surrounding areas.
3) The number, type, size, and location of connection requests received by Toronto Hydro are factors that inform whether an expansion to the distribution system is required. As elaborated in Section 3.1, expansion work can significantly impact program expenditures as it typically requires a substantial amount of resources to plan and construct the infrastructure necessary to connect a customer.
4) Capacity relief and additional capacity provisions completed under other System Access and System Renewal programs. For example:
   - Areas with load constraints may be relieved under the Load Demand program.
   - Assets replaced to current standards under the Overhead System Renewal program may indirectly include additional capacity provisions for future purposes.
   - Current standards do not specifically aim to increase capacity to facilitate new connections, but rather aim to minimize disruptions and achieve cost efficiencies and savings. For example: (i) poles are replaced with higher or stronger poles to accommodate additional circuits without having to replace the new poles in the future; and (ii) additional ducts may be installed when ducts are rebuilt to leverage trenching costs and avoid future costs.
   - The resulting capacity relief will allow Toronto Hydro to connect customers more efficiently, reducing expansion requirements to the distribution system and consequently reducing connection costs.

Toronto Hydro's customer charges or allowances associated with the work are established pursuant to the DSC, and Toronto Hydro's Conditions of Service. Connection asset related work, less any allowance, is paid for by the customer. Expansion asset related work is evaluated using the Economic Evaluation Model[22] to determine capital contribution and expansion deposit requirements to be met by the customer. One set of allowances are the Basic Connection Fees. As per Revision 17 of the Conditions of Service, Toronto Hydro's Basic Connection Fees are shown in Table 10.[23]

[22] As defined in Section 3 and Appendix B of the DSC.
[23] Fees are reviewed annually and updated with notice to customers when Toronto Hydro's Conditions of Service is revised.

Table 10: Basic Connection Fees

Customer Class		Basic Connection Fee
Class 1 to 5		$1,396
Unmetered (excluding street lighting)	*Overhead Supply*	$446 or $1,011
	Underground Supply	Collected directly from Customer

The contributions filed in the last application assumed a gross spend (and capital contribution ratio of 25 percent) identical to the 2014 historical, which was further adjusted as anticipated Metrolinx costs and contributions were added. However, the actual contributions received in 2015 and 2017 exceeded the forecast by $36 million. Therefore, to smooth any cyclical trends and better reflect actual contributions, the 2020-2024 forecast utilizes the average capital contribution of 46 percent experienced during the most recent 5-year period (i.e. 2013 to 2017).

Overall, for the 2015-2019 period, the load connection segment is forecasted to be within 5 percent of gross expenditures initially planned, however, recovered capital contributions were 90 percent higher than what was initially planned. This resulted in lower net expenditures.

The Customer Connections program is driven by customer service requests and as such, Toronto Hydro ranks and prioritizes jobs in this Program in accordance with the schedules and timelines of individual customers and service requests.

For customers requiring basic connections, prioritization is conducted on a first come, first served basis, taking into account the in-service date requested by the customer. This prioritization applies where Toronto Hydro has sufficient physical infrastructure, such as through overhead or underground lines, to enable the connection as well as adequate capacity on the relevant distribution feeder cable and station bus. Furthermore, customer timelines are considered to minimize disruptions or allow for efficiencies, whenever possible.

Wherever civil or electrical capacity is constrained or reliability is a concern, the connection is completed once the constraints are addressed by an expansion or system enhancement. For connections that cannot be completed without an expansion, prioritization of the work is determined in accordance with the timelines and requirements stated in the OTC.

E5.1.4.2 Generation Connections

Table 11: Historical & Forecast Program Costs ($ Millions)

		Actual			Bridge		Forecast				
		2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Generation Connection	*Gross*	0.9	0.6	0.8	3.4	2.8	2.9	3.5	3.2	4.1	4.5
	Customer Contribution†	(1.8)	(0.2)	(1.0)	(3.4)	(2.8)	(2.9)	(3.5)	(3.2)	(4.1)	(4.5)
	Net[24]	**(0.9)**	**0.4**	**(0.2)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

† Work and costs associated with additional modifications to the distribution system to incorporate renewable generation into the system are not paid for by the customer, and therefore, not covered under this Program. Such work and costs are discussed in the Generation Protection, Monitoring, and Control program see Exhibit 2B, Section E5.5.

The Generation Connection forecast has been compiled based on historical trends, completed assessments, and anticipated projects. A linear approximation was used to forecast the anticipated number of connections and total generation from 2018 through 2024. The forecast assumes the following:

1) The microFIT & FIT program will transition to a net metering program in 2018, as per the direction issued by the Minister of Energy on April 5, 2016;
   - no major changes will be introduced to the net metering program from 2020 to 2024;
2) A steady 3 percent increase year-over-year for renewable connections;
   - 90 micro and 60 small sized renewable connections in 2019 are used as the baseline;
3) Increased demand for energy storage connections due to reductions in lithium-ion battery prices;
   - 12 micro, 5 small and 3 medium sized energy storage connections in 2019 are used as the baseline, and a 20 percent increase year-over-year is used to forecast 2020-2024 connections;
4) Increased demand for CHP and diesel connections due to customers seeking site reliability and electricity charge reductions;

[24] All DG connections are 100 percent funded by capital contributions from the customer, and consequently, there should be zero net expenditure for DG connections. However, due to the pacing and timing of a DG installation, capital contributions may be collected from the customer in one year whereas the gross expenditures may span several years. As a result, the 2015- 2017 historical yearly total net expenditures do not equal zero.

- 15 small and 2 medium sized natural gas connections in 2019 are used as the baseline, and a 15 percent increase year-over-year is used to forecast 2020-2024 connections; and
- 1 small and 4 medium sized diesel connections in 2019 are used as the baseline, and an extra unit is forecasted to be added every two years.

Table 12 and Table 13 below provide a breakdown of work units and costs associated with the Generation Connection program based on generation type and size.

Table 12: 2015-2019 Volumes (Actual/Bridge)

Generation Type	Actual			Bridge		Total
	2015	2016	2017	2018	2019	
Micro (Renewable & Energy Storage)	122	124	155	247	102	**750**
Small Renewable	251	24	89	99	71	**534**
Small (Natural Gas, Diesel & Energy Storage)	2	2	3	22	23	**52**
Medium (Renewable, Natural Gas & Energy Storage)	1	2	2	6	2	**13**
Medium (Diesel)	3	2	-	8	8	**21**
Large (Natural Gas & Energy Storage)	-	-	-	-	3	**3**
Large Diesel	-	-	-	-	1	**1**

Table 13: 2020-2024 Volumes (Forecast)

Generation Type	Forecast					Total
	2020	2021	2022	2023	2024	
Micro (Renewable & Energy Storage)	108	114	121	129	139	**611**
Small Renewable	62	64	66	68	71	**331**
Small (Natural Gas, Diesel & Energy Storage)	25	30	36	43	51	**185**
Medium (Renewable, Natural Gas & Energy Storage)	4	4	4	5	5	**22**
Medium (Diesel)	9	10	11	13	14	**57**
Large (Natural Gas & Energy Storage)	1	2	-	1	1	**5**
Large Diesel	-	1	-	-	1	**2**

Toronto Hydro does not propose any net expenditure under this Program for the years 2020 to 2024 as all DG connections are 100 percent funded by capital contributions from the customer. Work and costs associated with additional modifications to the distribution system to incorporate renewable generation into the system are not paid for by the customer, and therefore, not covered under this Program but under the Generation Protection, Monitoring, and Control program.[25]

Toronto Hydro has a dedicated generation planning team that supports DG connections. The team works closely with customers to ensure the DG connection process is followed and timelines are met. Generation connections, like customer load connections, are processed and completed on a first come first serve basis. As such, the proposed investment pacing of this Program is based on historical trends, completed assessments, and anticipated projects.

E5.1.4.3 Cost Management

Toronto Hydro integrates the connection work with its planned construction activities to help ensure that the scope, nature and timing of the connection work does not adversely affect the utility's existing customers and planned work program.

If Toronto Hydro anticipates that load growth will require additional infrastructure upgrades beyond what is required under the expansion work set out in the OTC, the utility will include the additional distribution work, which can range from installing larger circuits to rebuilding cable chambers, as a part of the project. Project costs are allocated to the respective programs (e.g. Load Demand, Externally Initiated Plant, Overhead System Renewal, or Underground System Renewal). This coordinated approach is more cost-efficient than returning to the same area at a later date to perform additional upgrades.

An example of this approach can be found in work along Toronto's Waterfront, where the required civil work to connect new condominiums and developments was augmented to include the additional infrastructure necessary to meet future demands and system requirements that are imminently expected based on the City's Precinct Plans and progress for the revitalisation project.

Wherever possible, Toronto Hydro also coordinates its connection work with construction activities undertaken by other utilities or municipal or provincial government agencies. For example, Toronto

[25] Exhibit 2B, Section E5.5.

Hydro is coordinating the expansion work for the Six Points Interchange with the City of Toronto's road allowance infrastructure construction schedule.

Where an expansion overlaps with a capital work program or another project, Toronto Hydro would connect customers under a temporary arrangement until the project is complete. Customer offers and sustainment work are reviewed and switching and restoration plans are made to assist with meeting customer demands.

E5.1.5 Options Analysis

E5.1.5.1 Option 1: Do nothing

Do nothing is not an option as Toronto Hydro would be violating the DSC as well as its Distributor License.

E5.1.5.2 Option 2 (Selected Option): Customer Connections Program

As customers request access to the distribution system, Toronto Hydro endeavours to connect them in the most efficient and economic means available. Specifically, Toronto Hydro aims to connect customers from the closest access points available; where possible.

Depending on the system and customer conditions (e.g. requirements, size, location, and timelines), capacity or access may not be available. In such cases, Toronto Hydro will consider alternative solutions to connect the customer. Such alternatives may include, but are not limited to, transferring existing customers to an alternative feeder to free capacity on the feeder in question, or upgrade, extend, or install feeders, transformers, switches or other relevant equipment, as required. Should multiple options exist to connect a customer, options are reviewed with the customer and any differences (financial or technical) are explained to the customer to allow for an informed decision.

The Customer Connections program is an integral program for Toronto Hydro for purposes of meeting customer service requests in accordance with its mandated service obligations. Without this Program, Toronto Hydro will not be able to serve and connect customers in the manner specified by its Distributor Licence and other applicable regulatory requirements.

E5.1.6 Continuous Improvement

E5.1.6.1 Productivity

In 2017, Toronto Hydro combined two of its design teams: Low Voltage and High Voltage. Prior to this, the Low Voltage team dealt with short turn around seasonal work while the High Voltage team dealt with larger developments that had long lead times. This merger has allowed the allocation and distribution of work across design team members in a more effective and efficient manner.

Toronto Hydro implemented an online form with standardized fields that customers complete in respect of their inquiries. This directs the customers' inquiry promptly and accurately to the correct resource thus minimizing the "bouncing" around of the customer from one department to another.

Wire transfer payments for customer connections have recently been implemented to provide customers with alternate and more efficient methods of payment. This increases efficiency by reducing the time required to receive and cash the funds, improves traceability and reduces the possibility of cheques getting misplaced. Furthermore, this eliminates the need for customers to mail cheques or travel to Toronto Hydro work centers to deposit cheques.

In 2016, Toronto Hydro piloted a Customer Relationship Management ("CRM") system to improve relationship management with customers, better manage status and progress of requests, and enhance project tracking. The pilot provided transparency and allowed Toronto Hydro to better manage requests by recording information such as when requests were received, milestone progress, response times, assigned designer, and project status. This pilot system led Toronto Hydro to consider expanding and implementing the CRM solution to capitalize on the potential benefits offered by the system.

E5.1.7 Execution, Risks & Mitigation

E5.1.7.1 Execution

Customer Connections involves the installation of connection, expansion, and/or enhancement assets, as defined by the DSC. The utility manages the work required under the Customer Connections program for Toronto Hydro. Customers or their representatives are required to consult with Toronto Hydro concerning the availability of supply, supply voltage, service location, metering, and any other details necessary to establish service.

Customers apply for new or upgraded electricity services and temporary power services in writing. Each customer provides Toronto Hydro with sufficient lead-time to ensure the timely provision of adequate electricity supply. Toronto Hydro communicates with the customer in a timely manner in accordance with the DSC and Toronto Hydro's Conditions of Service.

Pursuant to the applicable provisions of the DSC and its Conditions of Service, Toronto Hydro does not connect customers if it has safety concerns or reason to believe that the connection would affect the reliability of its distribution system. A load analysis is performed for each customer request to ensure that the requested connection would not overload Toronto Hydro assets above their rated capacity. For large connections, this analysis also includes protection and coordination studies to ensure the proper protection is in place and to avoid damage to equipment and potential safety risks.

During the consultation and design phase of a customer's request, if a connection could potentially degrade the reliability of the relevant feeder or station, expansion work is deemed necessary to increase capacity or transfer load so that the current level of reliability is maintained.

Toronto Hydro provides customers with an OTC within 60 days from the day all required information is received. The customer is presented with a job quotation or a "short form" OTC, should the connection not require any expansion. Otherwise, the customer is provided with a "long form" OTC.

Customers are required to accept and make all OTC payments within 60 calendar days of receiving the OTC. Once an OTC is executed, the resulting work is to be carried out by Toronto Hydro resources unless the customer pursues an alternative bid where allowed by the OTC.

E5.1.7.2 Risks & Mitigation

Following are a number of risks that may affect the completion of the Program, and associated actions aimed to eliminate or manage such risks:

- **Capacity upgrade requirements**: Due to the increasing quantity and size of customer service requests, Toronto Hydro anticipates that many future connections will require expansion work to deal with capacity constraints. Typically these expansions have long lead times that could present a challenge to Toronto Hydro in meeting the customer's required timelines for connection. The increasing complexity of connections, which may require additional capacity/equipment from Hydro One, may not allow Toronto Hydro to deliver an OTC within 60 days. Toronto Hydro will continue to:

- Use long term forecasting, including analysis of city area and development plans in order to address growth early on and proactively upgrade or install required assets through enhancement work to the system; and
- Engage customers early on in the process to determine needs and assess impact on distribution system.

- **Customer timelines and requirements**: Customers' changing requirements, load demand, deadlines, and delays in providing information, signing offers to connect, and providing payments present a risk to project timelines. These issues could consequently impact resource allocation and timeliness of completion of the project in question (and other projects as well). Additionally, an expedited construction schedule by the customer and/or a strain on Toronto Hydro resources risks the utility’s ability to complete the project on time and meet the customer’s timeline. Toronto Hydro strives to identify and mitigate these risks early on during the design and consultation phase. Toronto Hydro communicates with the customer in a timely manner in accordance with the DSC and Toronto Hydro's Conditions of Service to ensure requests are continuously progressing. Customers are informed of expectations, timelines, and requirements early on through proper communications. Customers are also required to accept and make all OTC payments within 60 calendar days of receiving the OTC.

E5.2 Externally Initiated Plant Relocations and Expansion

E5.2.1 Overview

Table 1: Program Summary

2015-2019 Forecast ($M): 23.2	**2020-2024 Forecast ($M):** 46.1
Segment: Externally Initiated Plant Relocations & Expansion	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Service, Public Policy, Financial, Reliability	

The Externally Initiated Plant Relocations and Expansion program (the "Program") captures work Toronto Hydro must undertake to relocate its infrastructure in order to accommodate construction by third parties. In addition, in some instances, the Program includes work that increases the capacity of Toronto Hydro's system where efficiencies can be achieved by pairing the expansion work with the required relocation work. Relocation requests by third parties are usually received from those required to maintain, upgrade, expand and improve existing public infrastructure such as roads, bridges, highways, transit systems and rail crossings. These governmental third parties include the City of Toronto and the Ontario Ministry of Transportation. Toronto Hydro also receives relocation requests from other agencies, such as Metrolinx, which it assesses in a fair and reasonable manner.

The City of Toronto is experiencing a period of significant infrastructure renewal, neighbourhood revitalizations, commercial development and large transit expansions. Toronto Hydro seeks to respond to relocation requests received from third parties in a safe, environmentally responsible, reliable, cost-efficient and timely manner. In pursuing this objective, the utility aims to meet its obligations under the *Public Service Works on Highways Act* ("PSWHA"),[1] section 3.4 of the Distribution System Code ("DSC") and agreements with third parties.

Typically, when relocations are required, Toronto Hydro replaces the existing facilities on a like-for-like basis. This approach represents the minimum investment required to allow Toronto Hydro to continue providing safe and reliable electricity distribution service. However, at times, the nature of the project is such that like-for-like replacements are not the most efficient or desirable option. In these cases, there will be an opportunity for Toronto Hydro to maximize construction efficiencies and increase the existing capacity at the same time a relocation project is completed. In these cases,

[1] R.S.O. 1990, c. P-49

Toronto Hydro reviews the relocation request in conjunction with its future plans, and, if efficiencies can be achieved, works with the third party to complete system expansion work in conjunction with the required relocation. When Toronto Hydro increases the capacity of its infrastructure during an externally initiated relocation project, this is known as an "expansion" for the purposes of this Program.

As mentioned above, the timing, pace and spending under this Program is driven by third party requirements outside of Toronto Hydro's control. The circumstances and discretion of third parties can cause schedules and project scopes to change. In order to mitigate against the unpredictable nature of the work in this Program, Toronto Hydro seeks base rate funding for committed capital projects only. Toronto Hydro also seeks the continuation of the Variance Account for Externally Driven Capital[2] to capture the difference between the capital spending embedded in base distribution rates and the actual spending over the 2020-2024 plan period. This approach will allow Toronto Hydro to fund necessary non-discretionary work, while protecting ratepayers from potential over recovery. Further details on this variance account can be found in Exhibit 9, Tab 1, Schedule 1.

E5.2.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by responding to relocation requests and undertaking necessary, timely and cost-efficient system expansion work to accommodate future growth and increase system access, which should reduce the frequency and duration of construction disruptions for local area residents.

[2] EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Order (December 29, 2015) at p. 50.

Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Complying with the *PSWHA*, which requires Toronto Hydro to work with prescribed entities to complete the relocation of Toronto Hydro infrastructure, when requested, and subject to the cost responsibility principles established therein; and ○ Complying with section 3.4 of the Distribution System Code by resolving relocation requests in a fair and reasonable manner.
Financial	• Contributes to Toronto Hydro's financial objectives by: ○ Obtaining, from third parties requesting distribution plant relocations, full or partial funding for newly installed/relocated assets pursuant to applicable cost sharing agreements; and ○ Combining externally initiated relocation work with expansion work where doing so provides a more prudent and cost-effective solution than conducting the expansion work at a later date.
Reliability	• Contributes to Toronto Hydro's reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Installing new infrastructure to current standards; and ○ Improving capacity, where required, through expansion work associated with the relocation.

E5.2.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Customer Service Requests, Capacity Constraints

E5.2.3.1 Mandated Service Obligations

The projects in this Program are driven by operational decisions of third parties that are beyond Toronto Hydro's control. As mentioned above, the PSWHA requires Toronto Hydro to work with public entities requesting relocation of hydro plant in a timely manner to promote the maintenance and improvement of public infrastructure. In addition, Toronto Hydro is compelled by section 3.4 of the DSC to resolve third party plant relocation requests in a fair and reasonable manner.

E5.2.3.2 Customer Service Requests

Responding to relocation requests by third parties is part of Toronto Hydro's customer service obligations, including those set out in the PSWHA, which require Toronto Hydro to work with certain third parties to complete relocations when requested. The scope, timing and pacing of externally initiated relocation projects are driven by operational and planning decisions of third parties, which are beyond Toronto Hydro's control.

E5.2.3.3 Capacity Constraints

The scope, timing and pacing of these relocation projects are driven by operational decisions of third parties that are beyond Toronto Hydro's control. However, construction work carried out by third parties does provide an opportunity to expand the distribution system in a manner that minimizes disruption to customers and is more cost-effective for ratepayers. To this end, Toronto Hydro reviews load demand projections in the vicinity of externally initiated relocation work to identify opportunities to increase capacity during a relocation project. When capacity needs are identified, Toronto Hydro integrates expansion work into the relocation project. This offers a more cost-effective solution than conducting the expansion work after the sponsor agency has completed its project.

E5.2.3.4 Program Need

Toronto Hydro undertakes the externally initiated relocations and expansions projects solely in response to the capital work initiated by third parties. Toronto Hydro is required to undertake this work under the applicable legislation for prescribed entities (see Requests from Road Authorities section below) and requests from other private parties are dealt with on a case-by-case basis. Any expansion work carried out under this Program is needed to meet anticipated future load growth, to allow Toronto Hydro to coordinate projects with construction work being carried out by third parties. This minimizes disruptions for customers and provides for an efficient and cost-effective solution.

The projects within this Program can be divided into three broad categories: (i) requests from prescribed entities ("Road Authorities") which are governed by the PSWHA; (ii) requests from other agencies; and (iii) expansion work undertaken in conjunction with the relocation work.

1. Requests from Road Authorities

The PSWHA outlines obligations for utilities with infrastructure on roads and those entities ("Road Authorities") that have control of the construction, improvement, alteration, maintenance and repair of a highway (e.g. City of Toronto, Ministry of Transportation of Ontario). For instance, typical relocation work arising from a City of Toronto initiated project includes relocating hydro poles to enable road realignment.

The PSWHA also provides a costs formula that dictates how costs will be allocated between the parties. The PSWHA establishes a framework for determining cost responsibility for the relocation work. Under this framework, the Road Authority and the operating corporation may agree upon the apportionment of the cost of labour employed in the relocation, but, if there is no such agreement then the labour costs are divided equally between the Road Authority and the utility, and all other costs of the work (such as material costs) are the responsibility of the utility. Consistent with past experience, Toronto Hydro estimates that it will recover approximately a third of the total relocation costs associated with projects from a Road Authority.

For relocation project components that are initiated by a third party and not covered under the PSWHA, such as streetscape improvement projects, Toronto Hydro aims to negotiate agreements that provide greater cost recovery than the default cost apportionment provided for under the PSWHA.

2. Requests from Other Agencies

Where the request is not originating from a Road Authority, the PSWHA does not apply. However, Toronto Hydro is still obligated, under section 3.4 of the DSC to respond to these requests in a fair and reasonable manner. In these cases, the initiating third party typically funds 100 percent of the relocation costs while Toronto Hydro funds any expansion work conducted in conjunction with the relocation work. Metrolinx projects, such as Eglinton Crosstown Light Rail Transit ("LRT") and Finch West LRT, and Toronto Transit Commission projects, such as the Scarborough Subway Extension and Easier Access Program, are examples of major projects not subject to the PSWHA provisions. In these cases, the third party funds 100 percent of the relocation work.

The Regional Express Rail is another large Metrolinx project that is also not subject to the PSWHA. However, the project is subject to a number of legacy rail crossing agreements that could affect the allocation of relocation costs. Toronto Hydro is working with Metrolinx to negotiate cost responsibility for relocation work, similar to other Metrolinx projects. If, as a result of these negotiations, Toronto Hydro must bear some of the relocation costs, these costs will be recorded in the Variance Account for Externally Driven Capital.

The locations of some of the other major proposed projects in this Program are shown in Figure 1.

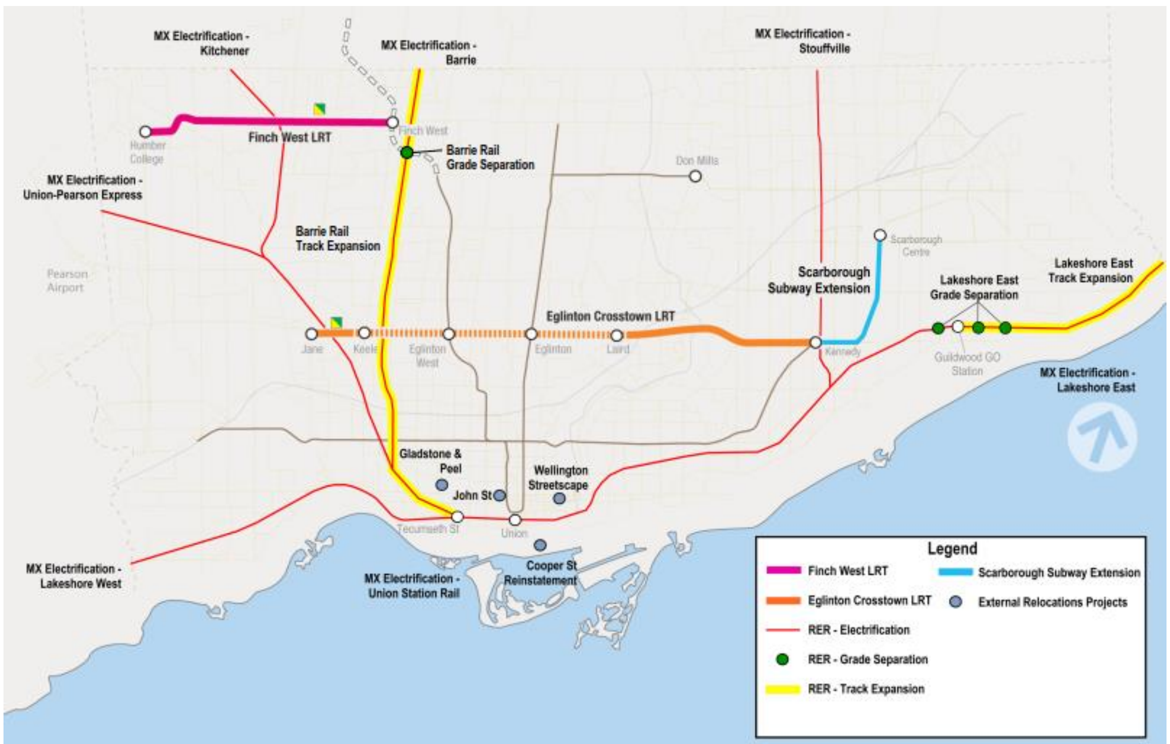

Figure 1: Major Externally Initiated Relocation & Expansion Projects to be constructed during the 2020-2024 Period

3. Expansion Work in Conjunction with Relocation Projects

Expansion work carried out under this Program is needed to meet anticipated future load growth. Pursuing expansion work in conjunction with the externally initiated relocation work allows required infrastructure to be installed where future construction may be restricted due to City streetscaping, commercial developments, City-imposed road work moratoriums or conflicts with other below grade utilities such as water, sewer, gas, and telecommunications.

Incorporating expansion work into the relocation work may result in significant cost savings compared to undertaking expansion work at a later date. Expansion work completed in conjunction with relocation projects may eliminate future third party utility relocation and coordination work, avoid additional restoration work and minimize disturbance to the general public. Further, undertaking expansion work in conjunction with relocation work ensures that Toronto Hydro infrastructure is installed in already congested rights of way without triggering the need for City approval of encroachment exemptions under the municipal consent requirements for infrastructure clearances. For instance, within the LRT transit corridors of the Eglinton Crosstown LRT and Finch West LRT, Toronto Hydro is taking the opportunity afforded by these relocations to expand its existing infrastructure in preparation for the expected load growth along the LRT lines.

E5.2.4 Expenditure Plan

Toronto Hydro's projected spending in this Program is based on committed capital plans from third party agencies including Road Authorities. Toronto Hydro gathers information on anticipated capital projects through direct consultation with external agencies, participation in the Toronto Public Utilities Coordination Committee, and reviewing governmental and public agency publications, including The Big Move, Metrolinx Five Year Strategy 2015-2020, MTO Southern Highways Program and the City of Toronto's 2017-2026 Capital Budget and Plan. These capital plans and project schedules are subject to change at the sole discretion of the sponsor agencies. Any such changes could impact the timing and execution of Toronto Hydro's relocation and expansion work. The projected quantum and timing of spending shown in Table 4, below, is based on the most current information available from third parties.

Table 4: Historical, Bridge and Projected Program Spending ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Project Cost	3.8	9.0	12.5	25.5	21.2	46.3	82.3	56.9	55.8	57.6
Capital Contributions	1.6	6.4	9.9	17.9	12.9	34.9	61.4	52.2	51.1	53.0
Net Cost	**2.2**	**2.6**	**2.6**	**7.5**	**8.3**	**11.4**	**20.8**	**4.6**	**4.7**	**4.5**

In its 2015-2019 Application, Toronto Hydro's forecast cost for the Externally Initiated Relocations and Expansions program was approximately $119 million.[3] This amount was derived from a number of large transit projects scheduled to be undertaken during that plan period by the Province and the

[3] EB-2014-0116, Toronto Hydro-Electric System Limited Custom Incentive Rate-setting Application (Filed July 31, 2014, Updated February 6, 2015), Exhibit 2B, Section E5.3, p. 10.

City. In recognition of the inherent volatility of work included in this Program, Toronto Hydro sought rate funding only for a base amount of approximately $20 million ($4 million of net Toronto Hydro costs per year) and the creation of a variance account to capture the annual differences from the base amount.[4] Toronto Hydro's approach was to ensure funding for necessary, non-discretionary work, while protecting ratepayers from over recovery should the forecasted third party work not materialize due to factors outside of Toronto Hydro's control. The appropriateness of this approach has been validated by the recognition that Toronto Hydro's costs[5] for the 2015-2019 plan period have been less than expected on account of the delay of several major projects.

Toronto Hydro's incurred capital expenditure costs in the 2015-2019 plan period were approximately $23.2 million. Major projects with significant construction activities planned for the 2015-2019 plan period were delayed due to a variety of factors outside of Toronto Hydro's control. These factors include: changes to City and Provincial funding priorities, changes in scope, unforeseen project complications, longer than expected agreement negotiation periods, delayed release or modification of budgets and delays in concluding qualified stakeholder procurement. As such, some of the costs of relocation and expansion work previously anticipated for the 2015-2019 plan period either did not materialize or have been deferred into the 2020-2024 plan period. For example, Toronto Hydro's projected spending is expected to significantly increase over the 2019-2021 period due to the deferral of the Eglinton Crosstown LRT and Finch West LRT relocation projects and associated expansion work.

Toronto Hydro identified a number of major projects that may commence in the 2020-2024 plan period. These are outlined below. Given the uncertainty associated with these projects, Toronto Hydro is seeking rate funding for committed capital projects only (i.e. Eglinton Crosstown LRT and Finch West LRT) during this plan period. If there are any changes to these major projects or any new projects emerge during this plan period, spending under this Program will increase. Therefore, Toronto Hydro requests the continuation of the Variance Account for Externally Driven Capital to record the difference between the capital spending embedded in base distribution rates and the actual spending in this Program over the 2020-2024 plan period.

[4] Ibid at p. 16.
[5] On an ISA basis.

E5.2.4.1 Major Projects

Key projects with anticipated completion in the 2020-2024 plan period, including projects which have carried over from the 2015-2019 plan period, are described below. A number of these projects are still in the scoping phase and, as such, the estimated relocation and expansion costs cannot be determined at this time.

1. Metrolinx Eglinton Crosstown LRT

This is a $5.3 billion investment by the Province of Ontario to expand transit in Toronto by constructing a 19-kilometre LRT line that will run along Eglinton Avenue from Mount Dennis (Weston Road) to Kennedy Subway Station. The project is being carried out by Metrolinx, a provincial Crown agency. Construction along a major corridor such as Eglinton Avenue, with established overhead and underground electricity, water, sewer, gas and telecommunications infrastructure, requires extensive relocation work to avoid conflicts with the construction activities, buildings and infrastructure (e.g. stations, stops, tracks and tunnels). Metrolinx has required that Toronto Hydro assets be relocated to accommodate construction activities which began before 2015. The construction work for this project is expected to continue until 2021, at which time the line is scheduled to go into service. Figure 2, below, shows a typical Eglinton Crosstown LRT Station Box.

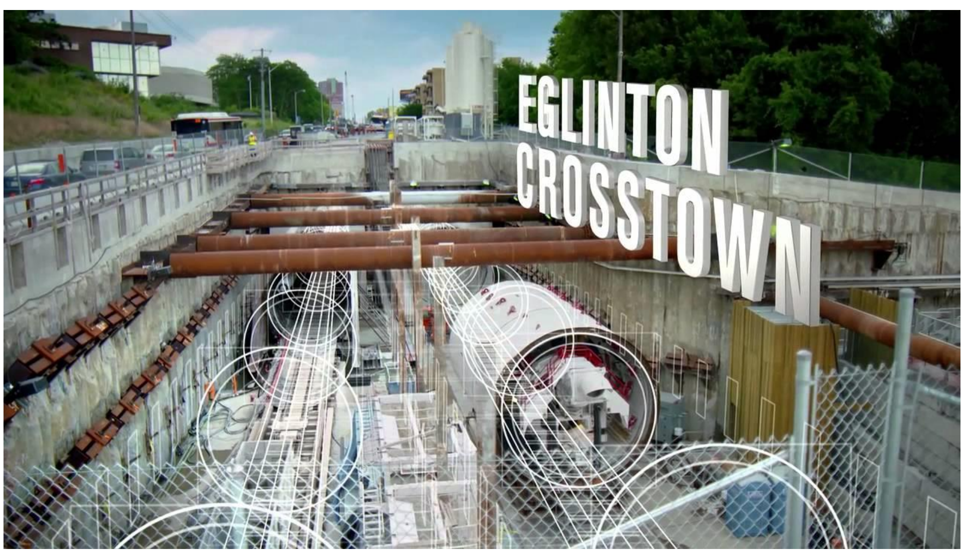

Figure 2: ECLRT Station Box

The project provides an opportunity for Toronto Hydro to undertake needed expansion work in the area. City and provincial policies have targeted the Eglinton corridor as an area of development and density. Construction of new underground assets by Toronto Hydro within the construction zone will relieve existing area capacity constraints and meet this future growth.

Completing expansion work in conjunction with the proposed construction allows Toronto Hydro to take advantage of construction efficiencies eliminating extensive future relocation work involving complex utility coordination, potential deviation on municipal consent requirements on infrastructure clearances and disturbances to the general public. Construction efficiencies may also be gained by utilizing the same trench for multiple utilities and avoiding additional restoration work. The expansion work is scheduled to occur between 2018 and 2021. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors.

2. Metrolinx Finch West LRT

This project is a $1.2 billion investment from the Province of Ontario, to be carried out by Metrolinx, to expand transit in Toronto by constructing an 11-kilometre LRT line that will run along the surface of Finch Avenue from Humber College (Hwy 27) to the new Finch West Subway Station. The at-grade LRT will operate on a dedicated right-of-way in the middle of the road. Figure 3, below, shows a typical LRT catenary system.

Figure 3: Typical Overhead Catenary System

With established overhead and underground infrastructure such as electricity, water, sewer, gas and telecommunications infrastructure, relocation work along the Finch West corridor is required to avoid conflicts with construction activities, equipment and infrastructure. Relocations are required to mitigate the conflict with the overhead catenary system for the LRT and Toronto Hydro's overhead distribution lines, as well as to maintain clearances between the LRT rail tracks and Toronto Hydro's underground civil infrastructure. The timeline for the relocation and expansion work is primarily based on the project schedule established by Metrolinx and its contractor. Construction activities will begin in 2018 and will continue into 2022 until this line is in service.

The City and Province have identified the Finch corridor as an intensification corridor where the upgraded transit services will allow for increased growth and development. Toronto Hydro is taking advantage of the relocation work to construct new infrastructure within the Finch West LRT corridor to alleviate capacity constraints and meet the anticipated load growth in the area. Securing expansion work at the same time may provide significant cost savings for ratepayers. These savings may be achieved through cost efficiencies in design and construction including, savings in trenching costs, bulk concrete purchase savings, insurance and digital mapping. Expansion work will be completed in conjunction with the required relocation work causing less disruption to the ratepayer and enabling cost savings due to the elimination of road cut restoration costs.

3. Metrolinx Regional Express Rail

The Regional Express Rail is a $13.5 billion investment from the Province of Ontario, to be carried out by Metrolinx, to enhance and update GO Transit infrastructure across the Greater Toronto and Hamilton Area to support more frequent, two-way, uninterrupted service via electric trains.

This initiative is a multi-year project on the GO rail network that will require extensive relocation of underground and overhead assets along the GO rail corridor in four project categories:

- **GO Electrification**: utilizing an overhead catenary system at 25 kV to operate electric motor trains and phase out diesel trains;
- **Grade Separation**: elevating the rail corridor to separate rail crossings from other modes of transportation;
- **GO Expansion**: expansion of rail tracks and associated infrastructure (i.e. tracks, rails and signals) to facilitate improved uninterrupted service; and

- **GO Station**: construction of new platforms, buildings, stations, traction power stations, parking and maintenance storage facilities to build a connected transit network.

As part of this project, Metrolinx requires the relocation of Toronto Hydro assets to meet infrastructure clearance requirements and to facilitate infrastructure, equipment and construction activities over the course of the proposed 10-year program. Figure 4 shows a typical GO Transit grade separation.

Figure 4: Typical Grade Separation

Toronto Hydro is reviewing available opportunities to take advantage of efficiencies in carrying out necessary expansion work in parallel with the required relocation work. The expansion work involves the construction of new infrastructure within the construction zone of the GO rail corridor and stations. The timing of the proposed work is dependent on the priority and construction of the grade separation, track expansion, electrification and station work determined by Metrolinx which involves relocation work, site preparation, construction and restoration work across the City of Toronto and the surrounding regions.

4. Toronto Transit Commission ("TTC") Scarborough Subway Extension

The TTC is constructing a realignment and extension of the Bloor-Danforth subway line to replace the existing Scarborough Rapid Transit line, also known as the Scarborough Subway Extension project. The 6-kilometre alignment starts from the east end of Kennedy Station, running in the northerly direction along McCowan Road and ends at the new Scarborough Centre Station. The TTC requires that Toronto Hydro's existing infrastructure be relocated as it is in conflict with this planned subway realignment and extension.

Figure 5: Construction Plan for Scarborough Subway Extension Station

There is work planned for 2018-2019 to relocate Toronto Hydro assets in order to facilitate tunneling at the launch shaft location near Scarborough Centre Station. The rest of Toronto Hydro's relocation work will be driven by the construction schedule for the tunnel and facilities. The planned completion year is 2026. Figure 5, above, shows a typical subway construction configuration. Toronto Hydro is reviewing available opportunities to take advantage of efficiencies in carrying out necessary expansion work in parallel with the required relocation work.

5. TTC Easier Access Program

The TTC initiated the Easier Access Program with the goal of making all of its services and facilities, including key subway and Scarborough Rapid Transit stations, fully accessible to persons with disabilities. The *Accessibility for Ontarians with Disabilities Act*, S.O. 2005 ("AODA") requires that all public facilities and services are accessible by 2025.

Significant subway station infrastructure is impacted by the need for AODA compliance, including the requirement that subway stations be constructed in a tiered configuration, similar to the one set out in Figure 6. Several of the impacted stations are located in the downtown area necessitating relocation of Toronto Hydro's infrastructure. Toronto Hydro has already completed relocation work for four stations. Nine additional station relocations are currently scheduled for completion in the 2020-2024 plan period. Toronto Hydro will evaluate available opportunities to take advantage of efficiencies in carrying out necessary expansion work in parallel with the required relocation work.

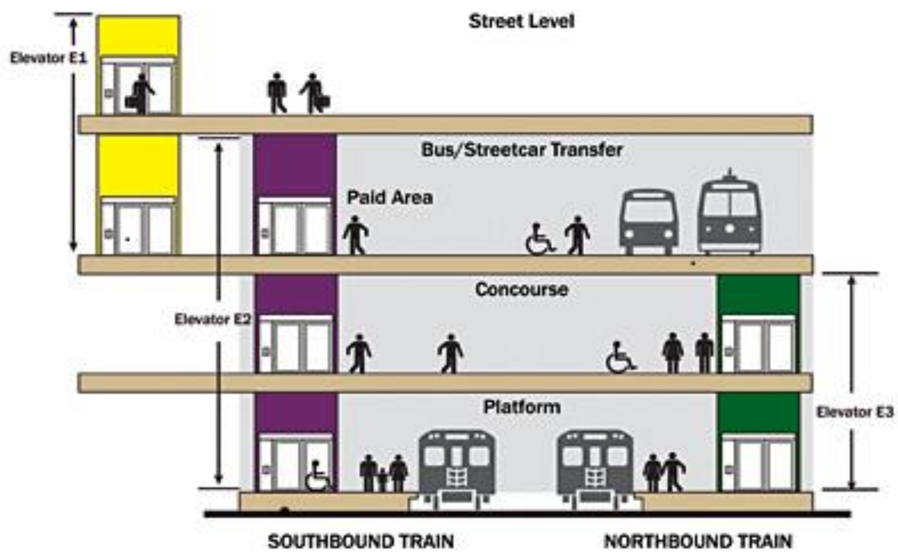

Figure 6: TTC Easier Access Station Concept

6. City of Toronto Projects

The City of Toronto has a $39.7 billion[6] capital budget and plan for 2017-2026 which includes a variety of local and City-wide projects dedicated to the modernization, transformation and renewal of the City. The City approached Toronto Hydro to relocate the utility's infrastructure in conflict with a number of these projects. There are currently 23 active relocation projects, including those in connection with major street development initiatives such as:

[6] City of Toronto 2017-2026 Capital Budget & Plan Executive Committee (Feb 2 2017).

- **John Street Revitalization:** The City and the Toronto Entertainment District BIA are transforming John Street into an arts and culture promenade between Front Street and Stephanie Street by implementing sidewalk widening, road improvements, beautification upgrades and event lighting. Overhead assets will be buried. Civil infrastructure assets required to connect the proposed development to the distribution system will also be installed.

Figure 7: John Street Revitalization Concept

- **Wellington Streetscape:** A public realm (streetscape) improvement initiative between Church Street and Yonge Street implementing sidewalk widening, boulevard improvements and beautification upgrades. The relocation work involves burying overhead electricity distribution assets and the installation of civil infrastructure to connect the development to the distribution system. Toronto Hydro will install additional ducts during the relocation work to address expected load growth in the area.
- **York-Bay-Yonge Ramp Demolition and Harbour Street Widening:** The City is constructing a new off-ramp from the eastbound Gardiner Expressway to Lower Simcoe Street to accommodate traffic flows into the downtown core and waterfront. The project includes the removal of the York-Bay-Yonge off-ramp, the construction of a new ramp ending at Lower Simcoe Street, and improvements to Harbour Street. This project requires the relocation of street-lighting kiosks, transformers and associated infrastructure, as well as the installation

of underground cables and ducts and the rebuilding of cable chambers that conflict with roadway improvement.

A number of rehabilitation projects are put forward every year by the City in connection with its capital plan. With continued City building initiatives and population growth projections, Toronto Hydro anticipates an increase in third party relocation activity during the 2020-2024 plan period pending City council budgetary approvals.

E5.2.4.2 Upcoming Projects

Additional projects that are still in preliminary stages may emerge in the current or next plan period. Government and public agencies such as Metrolinx, TTC, and the City of Toronto have approached Toronto Hydro regarding their initiatives to expand and improve transit and to revitalize public space including, but not limited to, the following projects:

- **Metrolinx**: ECLRT Expansions – Eglinton West LRT and Eglinton East LRT
- **TTC**: Downtown Relief Line and the Yonge Extension to York
- **Waterfront Toronto**: Port Lands Revitalization Waterfront Toronto
- **City of Toronto**: Yonge Street Reimaging
- **City of Toronto**: Port Union Road Widening – Lawrence Ave E to Island Road
- **City of Toronto**: Algonquin Island Bridge
- **City of Toronto**: Scarlett Road Bridge & Road improvement (See Figure 8 below)

Figure 8: Scarlett Road Bridge & Road Improvement Concept

E5.2.5 Options Analysis

E5.2.5.1 Option 1: Completing Externally Driven Relocation Work Only

Toronto Hydro is obligated to relocate its electricity distribution in response to road authorities defined under the PSWHA and respond to relocation requests by third parties in a fair and reasonable manner. As mentioned elsewhere, in general, when relocations are required, Toronto Hydro replaces the pre-existing facilities on a like-for-like basis. This approach constitutes the minimum investment on part of Toronto Hydro to continue providing safe and reliable electricity.

E5.2.5.2 Option 2 (Selected Option): Completing Externally Driven Relocation Work and Expansion Work

Sometimes the nature of a project is such that it is not the most efficient or beneficial option to undertake only relocation work. Upon receipt of a relocation request, Toronto Hydro reviews the future capacity needs in the area and evaluates whether there are opportunities for construction efficiencies available to support undertaking expansion work along with the relocation work. An example of how expansion and relocation work may be combined to maximize efficiencies is the Wellington Streetscape Improvement Initiative.

The Wellington Streetscape Improvement Initiative is a project of the City of Toronto to improve the streetscape along Wellington between Church Street and Yonge Street. Upon being advised of the project by the City, Toronto Hydro worked with the City to identify what infrastructure needed to be relocated and developed a plan to relocate and replace the existing plant according to current standards. Toronto Hydro also reviewed its capital plan to identify expansion work opportunities that could be executed along with the relocation work. Toronto Hydro performed a system analysis to determine expected load growth on the feeders in the area. In reviewing the current feeder loading conditions and approved loads through customer connections and factoring in contingency scenario loading, Toronto Hydro determined that by 2022, seven of nine local feeders would be heavily loaded, requiring relief. To accommodate this anticipated growth, expansion work was integrated into the work plan to be executed during plant relocation initiatives.

Executing expansion work in coordination with the City's capital work was determined to be preferable to only undertaking the relocation work for the following reasons:

- It may be less expensive to construct new civil infrastructure to support the expected load growth in the area if such work is undertaken in conjunction with the relocation work required by the City's project. If the expansion work is undertaken in the future there would be a need for increased coordination initiatives with third party utilities, more potential for deviation from municipal consent requirements on infrastructure clearances and additional civil construction and restoration work in the area.

- The City's road cut moratorium could prevent Toronto Hydro from installing additional infrastructure when needed to address the expected load growth. The City of Toronto imposes a five-year moratorium on road cuts in an area after road resurfacing is completed. Breaking the moratorium requires City approval and payment of a fee. Failing to complete expansion work during the relocation phase of a project could lead to Toronto Hydro having to install more costly and less optimally located facilities to meet the anticipated demand.
- Completing the expansion work and the relocation work together avoids prolonged disturbances to the residents and businesses in the neighbourhood.

E5.2.6 Distribution Grid Operations Consultation

Consultation with Toronto Hydro's Distribution Grid Operations ("DGO") Department, which coordinates all work on the distribution system, early in the design process improves outcomes for third parties and customers more broadly. Early consultation allows the DGO to sequence work on feeders to accommodate third party relocation work more quickly while minimizing disruptions to customers in the area. The DGO also provides an operational perspective during design review. DGO is able to identify design modifications to improve system reliability early on, thereby avoiding any delay to the overall project.

E5.2.7 Execution Risks & Mitigation

Toronto Hydro's projected spending in this Program is based on a combination of deferred projects from the last plan period, future committed projects and anticipated projects. There is risk that projects in these categories or their timing may be modified or may not materialize as anticipated. In addition, new projects can emerge, adding to program costs. To mitigate the effects of these scenarios for ratepayers, Toronto Hydro requests the continuation of Variance Account for Externally Driven Capital.

The projects proposed under this Program are largely dictated by the schedule and plans of third parties. Third parties often face their own constraints with respect to the execution and completion timelines for their projects. For example, the timing and cost of projects can be affected by City initiatives such as the King Street Pilot Project. This project aims to improve transit reliability, speed and capacity along King Street and includes limits on the type and timing of construction in the area during the day. These limits may impact project schedules and increase costs arising from the need to undertake work during off-peak hours on evenings and weekends. Toronto Hydro constantly monitors changes to codes, bylaws and legislation which impacts its relocation operations to ensure that its processes and standards align with requirements.

E5.3 Load Demand

E5.3.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 81.9	**2020-2024 Cost ($M):** 87.5
Segments: N/A	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Service, Reliability, Safety	

With increasing land development and growth in Toronto Hydro's service territory, the Load Demand program (the "Program") aims to alleviate emerging capacity constraints to ensure the availability of sufficient capacity to connect customers to Toronto Hydro's distribution system efficiently. In doing so, the Program also seeks to minimize the effect of load growth on existing customers. Toronto Hydro's investments in this Program enable the operation of its distribution system under first contingency scenarios,[1] as well as the minimization of potential switching restrictions during summer peak conditions (which can impede the utility's ability to execute maintenance and capital work during summer months). This Program is a continuation of the activities described in the Load Demand program in Toronto Hydro's 2015-2019 rate application.[2]

More specifically, the Program alleviates overloaded equipment and capacity constraints on the distribution system through:

- Load transfers between feeders and station buses to relieve overloads;
- Electrical and civil enhancements to enable capacity upgrades; and
- Cable upgrades, load transfers and equipment upgrades in network vaults to reduce the number of switching restrictions experienced during the summer peak.

[1] "First contingency" occurs when any one primary feeder, transformer, or other critical equipment is lost, either due to a fault or planned outage

[2] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 2B, Tab 5, Schedule E5.4.

E5.3.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Customer Service	• Contributes to the sustainment of service connection targets established by the OEB (i.e. the Electricity Service Quality Requirements) for new residential, small business services, and high voltage services by undertaking targeted capacity upgrades, primarily in the downtown core and areas of high load growth. • Contributes to customer satisfaction results by providing large customers flexibility in scheduling substation maintenance by reducing summer peak switching restrictions.
Reliability	• Contributes to maintaining Toronto Hydro's System Capacity measure, and reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Improving restoration capabilities and reducing customer interruptions by providing additional capacity or maintaining spare capacity through cable upgrades and load transfers; ○ Improving restoration capabilities in the downtown system by decreasing the number of highly loaded feeders expected by 2024. ○ Improving restoration capabilities in the Horseshoe system by conducting load transfers for 6 feeders in the high growth areas; ○ Improving system reliability by reducing the risk of failures due to highly overloaded equipment through mitigation of expected bus overloads; and ○ Improving downtown reliability by reducing and maintaining the number of heat restricted feeders.
Safety	• Contributes to Toronto Hydro's safety performance objectives (as measured through measures like Total Recordable Injury Frequency) by reducing the failure risk of overloaded infrastructure to Toronto Hydro workers and members of the public.

E5.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Customer Service Requests, Reliability, System Efficiency

E5.3.3.1 Mandated Service Obligations

Toronto Hydro is required to ensure its distribution system can support projected load growth while maintaining reliability and quality of service for customers on both a short-term and long-term basis, as required by sections 3.3.1 and 4.4.1 of the Distribution System Code ("DSC"). Toronto Hydro must also connect new customers within the timelines prescribed by the OEB's service quality standards[3] without adversely affecting the quality of distribution services for existing customers, with 97 percent of new residential and small business services completed on time; and 99 percent of new high voltage connections completed on time.

To satisfy these requirements, Toronto Hydro must maintain sufficient capacity on its system to keep pace with load growth and ensure that its assets are not overloaded (i.e. an overloaded bus is defined as reaching 95 percent of its firm capacity under normal and emergency operating conditions). Highly loaded downtown feeders are defined as feeders that exceed cable ratings under contingency, assuming peak customer loads and a coincidence factor of 1 (i.e. all customers peak at the same time). In the Horseshoe area, sufficient relief must be provided on feeders in high growth areas. The investments in this Program are specifically targeted to meet these mandated service obligations.

The rapid influx of new dense load in the downtown core and Horseshoe areas (see section E5.3.3.2 for more details) poses a challenge for Toronto Hydro to meet its service requirements, as the rapid growth is causing bus loadings to approach their rated capacity (95 percent) over the 2019-2024 period. The forecasted growth in the distribution system is based on the Toronto Hydro 2017 Station Load Forecast.

As discussed in greater detail below, critical parts of Toronto Hydro's distribution system (such as the downtown and Central Waterfront areas) that service a large amount of load or are experiencing high growth are at risk of overloading already highly loaded downtown feeders, with additional overloading expected in the upcoming years. These areas are seeing growth associated with multiple

[3] DSC, section 7.2 Connection of New Services: low voltage (<750 Volts) within 5 business days and high voltage (>750 Volts) within 10 business days.

storey residential condominiums, mixed use buildings and large commercial developments. If no action is taken to alleviate the constraints presented by the highly loaded feeders, load shedding will be required during the summer peak period to mitigate the risk of failure from overloaded equipment. This involves dropping customer loads when the feeders or the equipment that supply them are overloaded so that a tolerable loading level can be maintained. Supplying customers through highly loaded feeders would reduce the level of reliability for downtown customers, thereby causing Toronto Hydro to fail in meeting the top priority of these customers as identified through customer engagement studies.

E5.3.3.2 Customer Service Requests

Toronto Hydro receives customer requests for service connections (called Applications for Service) every time there is a new residential, industrial, or commercial development, or when upgrades are required for an existing connection. Applications for Service are processed as part of the Customer-Driven Work program.[4] In most cases, System Planning[5] input is also required to determine how to service the customer in the most efficient manner. The utility's ability to respond to customer service requests within the OEB-prescribed timelines,[6] without affecting the quality of service for existing customers, is largely dependent on the investments made in this Program. Toronto Hydro relies on the City of Toronto's land planning information to help assess what areas of the system require additional capacity to accommodate customer service requests in a timely and cost-effective manner.[7]

Figure 1 shows the load additions submitted to Toronto Hydro from 2013 to 2017 by geographical region. Figure 2 shows the resulting load impact in each region of the City.

[4] Exhibit 4A, Tab 2, Schedule 8 Customer-Driven Work.
[5] Exhibit 4A, Tab 2, Schedule 9 Asset and Program Management.
[6] DSC, section 7.3 Connection of New Service.
[7] City of Toronto (2017, Apr.). "How Does The City Grow?" Available: https://web.toronto.ca/wp-content/uploads/2017/08/9014-How-Does-the-City-Grow-April-2017.pdf

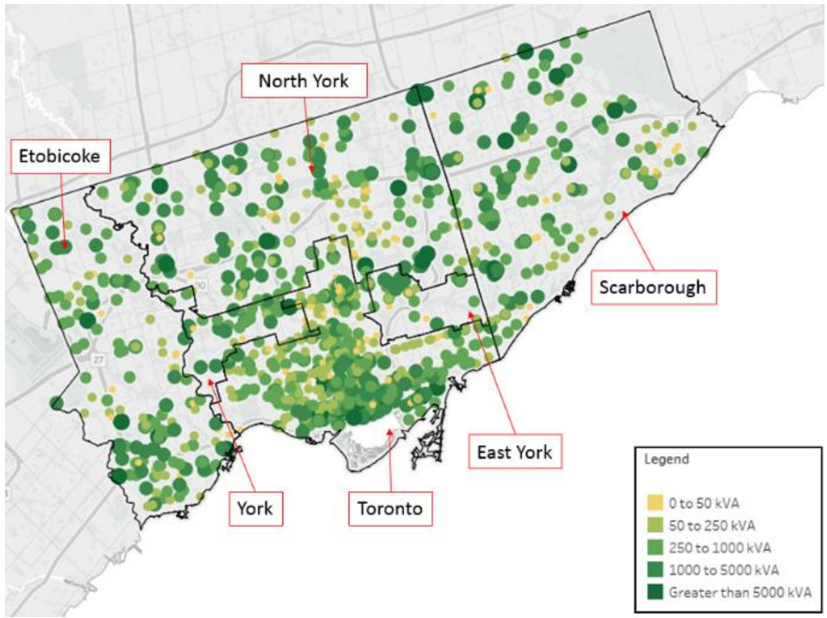

Figure 1: Load Additions in the City of Toronto during the 2013-2017 Period

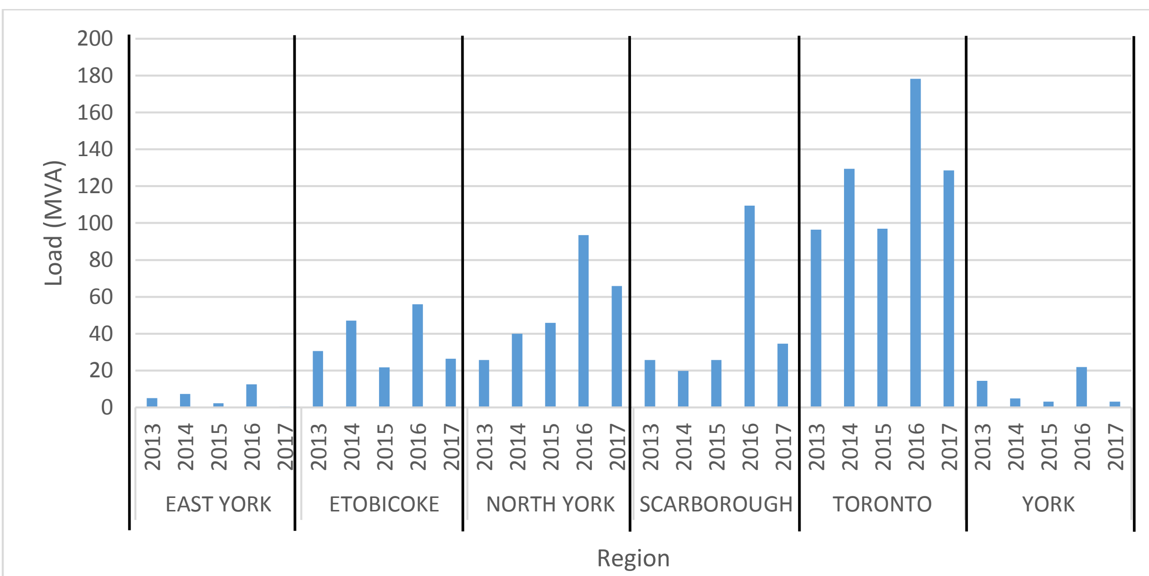

Figure 2: Load Additions by Region during the 2013-2017 Period

The City of Toronto is experiencing an increase in development which is expected to continue throughout the 2020-2024 period. Table 4 below provides a summary of the projects submitted to the City of Toronto's Planning Division between 2012 and 2016, and Figure 3 is a map of the residential units proposed over this period.

Table 4: Proposed Projects in the City of Toronto (2012-2016)[8]

	Built	Active	Under Review	Total in Pipeline	% of Total
City of Toronto	**1,156**	**743**	**624**	**2,523**	
Growth Areas					
Downtown and Central Waterfront	**187**	**129**	**132**	**448**	**17.8**
Centres	**28**	**34**	**26**	**88**	**3.5**
Etobicoke Centre	6	10	3	19	21.6
North York Centre	14	9	9	32	36.4
Scarborough Centre	4	3	1	8	9.1
Yonge-Eglinton Centre	4	12	13	29	33.0
Avenues	**174**	**154**	**147**	**475**	**18.8**
Other Mixed Use Areas	**79**	**82**	**55**	**216**	**8.6**
All Other Areas	**688**	**344**	**264**	**1,296**	**51.4**

Source: City of Toronto, City Planning Division: Land Use Information System II

Development projects with activity between January 1, 2012 and December 31, 2016. Built projects are those which became ready for occupancy and/or were completed. Active projects are those which have been approved, for which building permits have been applied or have been issued, and/or those which are under construction. Projects under review are those which have not yet been approved or refused and those which are under appeal.

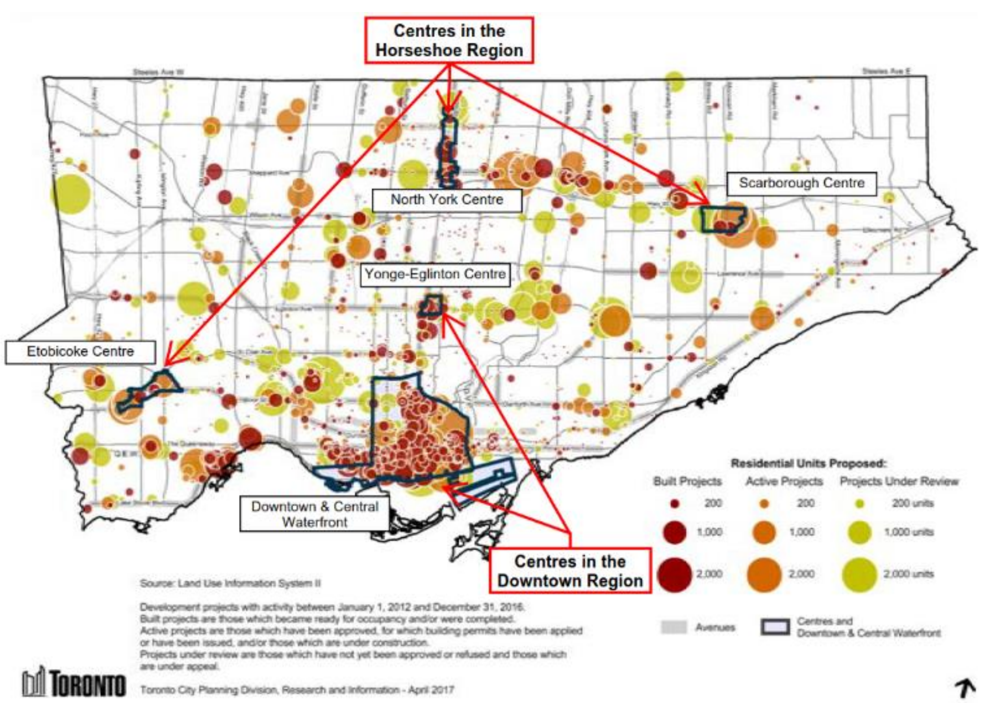

Figure 3: Residential units proposed (2012-2016)

[8] *Supra* Note 8.

As illustrated in Figure 3, the majority of the growth is focused on the downtown system, particularly the downtown and Central Waterfront area, where 42,556 residential units have been built as of the end of 2016 and 141,079 units are in the pipeline for future development. Another area experiencing strong growth in the downtown system is the Yonge-Eglinton Centre, with 1,329 units built by 2016 and 12,975 units in the pipeline.

In the Horseshoe system, Etobicoke Centre, North York Centre, and Scarborough Centre have experienced development growth which are expected to continue: (i) in the Etobicoke Centre area, 970 units were built and 7,261 remain in the development pipeline; (ii) in the North York Centre area, 4,052 units were built and 8,819 remain in the pipeline; and (iii) in the Scarborough Centre area, 853 units were built and 1,591 remain in the pipeline.[9]

Of the total projects proposed over the 2012-2016 period, 123,710 residential units and 3,046,196 m^2 of proposed non-residential Gross Floor Area ("GFA") are currently in the development pipeline as active projects.[10] Based on a load estimate of 2 kVA per residential unit[11] and 0.07 kVA per m^2 of non-residential GFA,[12] Toronto Hydro expects that these projects will result in up to an estimated 460 MVA of new load during an estimated 3 to 7 years after the end of the 2020-2024 period. This estimated load addition does not take into account load subtractions to the distribution system due to redevelopments. Therefore the actual net new load may vary. Furthermore, the actual load added to the distribution system will depend on customer load factors and the system coincidence factors.

Therefore, the utility can expect a steady stream of customer service requests for new connections over the 2020-2024 period and beyond.[13] To meet these requests in a timely and cost-effective manner, and maintain reliability and quality of service for existing customers, Toronto Hydro must invest in infrastructure upgrades and load transfers to alleviate capacity constraints. In particular, the utility must focus its efforts in the downtown area where concentrated growth is straining the distribution system by overloading station buses, feeders, and transformers.

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[9] *Supra* note 8.
[10] *Supra* note 8.
[11] OEB, Backgrounder – May 1 electricity price change (2016). Available: https://www.oeb.ca/oeb/_Documents/Press%20Releases/bg_RPP-TOU_20160414.pdf
[12] H. Joshi, "Load Estimates," in Residential, Commercial and Industrial Electrical Systems: Network and Installation, Volume 2, 1st ed. (McGraw-Hill, 2008), pp. 3.
[13] Canada Mortgage and Housing Corporation reports that from 2007 to 2016, an average of approximately 14,700 residential units were built each year. This information confirms that active residential projects will likely be completed in the 2020-2024 rate period. (City of Toronto (2017). "How Does the City Grow?" *Supra* Note 8)

E5.3.3.3 System Reliability and Efficiency

This Program aims to ensure that the system has enough capacity to restore customers during contingency events and that asset failure and loss of supply due to overloading are prevented. Operating assets loaded above their rated capacity for prolonged durations increases their risk of failure and corresponding loss of supply to customers. The risk of overloading is highest during the summer months when system load peaks. These conditions can lead to the premature failure of primary overhead conductor and undersized legacy assets (i.e. underground paper insulated lead-covered "PILC" cables), that were installed over 25 years ago when standard trunk cables were approximately 30 percent smaller and had a 25 percent lower current capacity. Since 2010, Toronto Hydro's distribution system has experienced 175 cable and splice failures on legacy PILC cable.[14]

Overloaded assets pose reliability and public safety risks. For example, the temperature of conductors and cables increases when they are overloaded which reduces the conductor's tensile strength.[15] Loss of the rated tensile strength can cause significant sagging of an overhead feeder line, which makes it more susceptible to external contacts and safety requirement violations.[16,17] Similarly, underground cables, such as the cross-linked polyethylene ("XLPE") cable used in the downtown system, soften as their temperature increases, particularly in areas where the insulation is under mechanical stress (e.g. bends in the route), thereby leading to deformation of the cable. This can lead to electrical failures resulting in outages.[18]

To meet the increasing need for capacity, ensure system reliability and efficiency, and meet the mandated service obligations, four types of work are carried out under this Program:

[14] These cables are addressed through the Underground System Renewal – Downtown program, see Exhibit 2B, Schedule E6.3.
[15] K. Adomah, Y. Mizuno and K. Naito. "Probabilistic assessment of the reduction in tensile strength of an overhead transmission line's conductor with reference to climatic data." *IEEE Transactions on Power Delivery*, vol.15, pp.1221-1224, 2000.
[16] F. Jakl and A. Jakl. "Effect of Elevated Temperatures on Mechanical Properties of Overhead Conductors under Steady State and Short-Circuit Conditions." *IEEE Transactions on Power Delivery*, vol. 15, pp. 242-246, Jan. 2000.
[17] Minimum Safety Clearance as in Toronto Hydro standard 03-2000 Overhead – Minimum Vertical Separations, where the exact clearance depends on the configuration of the pole, the type of attachments on it, and primary voltage.
[18] S. H. Alwan, et al. "Factors Affecting Current Ratings for Underground and Air Cables." *International Journal of Energy and Power Engineering,* vol. 10, pp. 1422-1428, 2016.

- **Bus[19] Level Load Transfers**: load transfers between station buses to alleviate overloaded buses.
- **Feeder[20] Level Load Transfers and Upgrades**: transferring loads between feeders to alleviate overloaded feeders or buses or upgrading undersized feeder trunks to the current standard.
- **Equipment Upgrades**: carried out in network vaults to increase unit size and associated capacity, which reduces the number of switching restrictions experienced during summer peaks.
- **Civil Enhancements**: carried out in duct banks and egress cable chambers to enable capacity upgrades such as cable upgrades.

1. Bus Level Load Transfers

Toronto Hydro plans to execute targeted load transfers on station buses that are expected to become overloaded based on the 2017 Station Load Forecast and those where opportunities will arise to redistribute load with adjacent station buses.[21]

Table 5 lists the specific station buses planned for bus level load transfers during the 2020-2024 period, and Figure 4 shows the stations' locations. Three types of planned transfers will be carried out:

- **Downtown Intra-station Transfers**: load transfer to another bus in the same station;
- **Downtown Inter-station Transfers**: load transfer from one station to another in the area;
- Load Transfers in the Horseshoe area of Toronto.

The completion of Copeland TS Phase 2 under the Stations Expansion program[22] will have the potential to enable load relief at Esplanade TS, Strachan TS, Windsor TS, Cecil TS, and Terauley TS.[23] For these stations, civil and cabling work to enable the transfers is planned to be undertaken before Copeland TS Phase 2 is energized, so that the full benefits of Phase 2 can be realized immediately

[19] **Bus** – A rigid, large conductor usually in substations, to provide a quick and convenient means of rearranging circuit connections to keep power flowing or to restore power after an outage.
[20] **Feeder** – A distribution circuit carrying power from a substation to customers. Feeders consist of circuits and other electrical equipment supported by civil infrastructure like poles and ducts.
[21] See Exhibit 2B, Section E7.5 Stations Expansion.
[22] See Exhibit 2B, Section E7.5 Stations Expansion. Copeland TS Phase 2 is expected to be completed by 2023/2024.
[23] Not all stations listed are addressed through the Load Demand program.

upon its energization. Relief for Horner TS and Manby TS are dependent on the Horner TS station expansion.

Table 5: Station Buses Planned for Relief within 2020-2024

Station	Bus	Target Year	Estimated Load to Transfer (MVA)	Planned Transfer Type
Cecil	*A5-6CE*	2020	2.5 - 10	Downtown Intra-station
Wiltshire	*A5-6W*	2020	5 - 20	Downtown Intra-station
Esplanade	*A1-2X*	2023, 2024	5 - 20	Downtown Inter-station
Basin	*A5-6BN*	2022, 2023	10 - 40	Downtown Inter-station
Horner	*B&Y*	2022, 2023	10 - 40	Horseshoe
Strachan	*(Note 1)*	2023,2024	5 - 20	Downtown Inter-station
Manby	*Q&Z, V&F*	2024	10 - 40	Horseshoe
Windsor	*(Note 2)*	2023,2024	5 - 20	Downtown Inter-station

Note 1: Targeting bus supplying feeders in area bounded by Spadina Ave, Rail Corridor, Strachan Ave, and Lake Ontario.

Note 2: Targeting bus supplying feeders in area bounded by Bathurst St, Adelaide St W, Yonge St, and Railway Corridor.

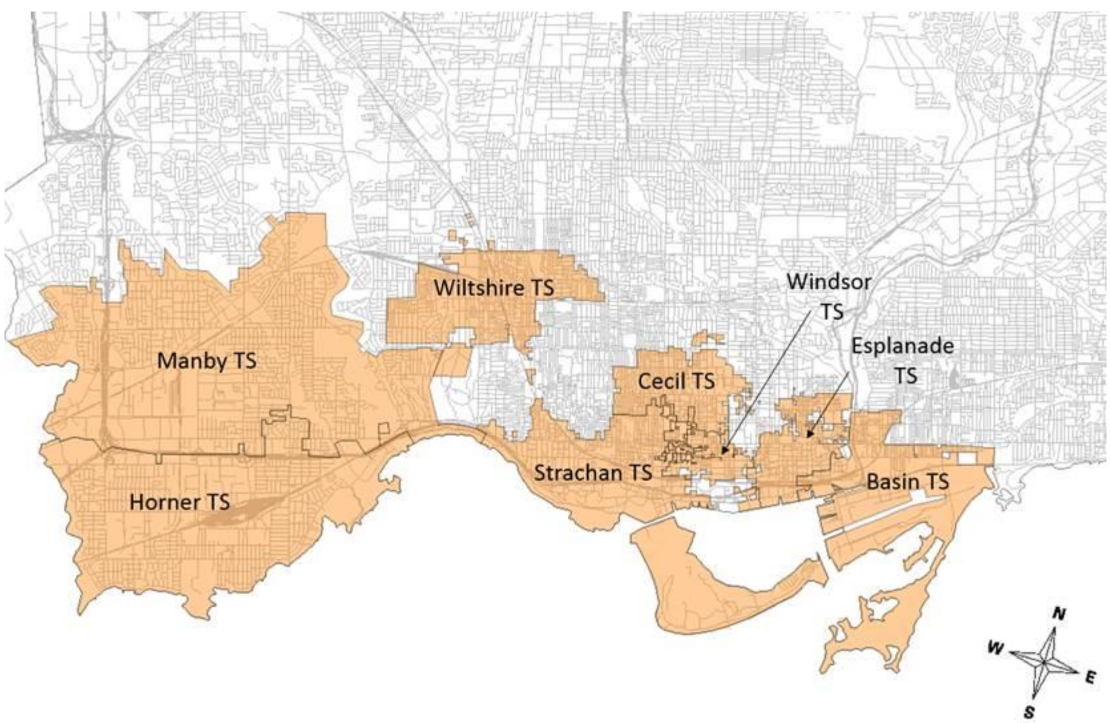


Figure 4: Stations Targeted For Relief during the 2020-2024 Period

If the buses outlined in Table 5 above are not relieved, it may not be possible to connect new customers to these station areas. As a result, new service requests in the areas serviced by these station may have to be supplied from adjacent buses or stations, potentially resulting in system inefficiencies, materially higher connection costs, and longer timelines to complete the work.

Station bus load forecasts are re-evaluated annually, as described in the DSP – Capacity Planning, [24] driven by information on expected new connections, expected load transfers and voltage conversions, re-evaluated growth rate, and the previous years' weather corrected peak which is used as base for load growth. Therefore, based on the outcomes, the need for specific load transfers can either be escalated in priority or deferred. Some of the buses that Toronto Hydro plans to address in the 2020-2024 period were originally planned for relief in the 2015-2019 period. For the reasons summarized in Table 6 below, the investments were deferred to the 2020-2024 period.

Table 6: Deferred Load Transfers from 2015-2019 to 2020-2024

Station	Bus	2015-2019 Referenced Year For Relief	2020-2024 Target Year For Relief	Reasoning
Basin	*A5-6BN*	2019	2022,2023	This transfer is awaiting new capacity at Carlaw TS to transfer load. In the interim, new customer loads will not be added to the A5-6BN bus or smaller transfers may be conducted until load can be relieved by the new capacity at Carlaw TS.
Horner	*B&Y*	2017	2022, 2023	Re-evaluation of load forecast indicated that relief was required in the 2022-2023 timeframe, which aligns with the expansion of the station.
Manby	*Q&Z, V&F*	2017 (Q&Z), 2018 (V&F)	2024	Deferred until the Horner station expansion is completed so that load can be transferred using the new capacity.
Strachan	*A1-2T*	2017	2023, 2024	Re-evaluation of load forecast indicated that relief is not required until 2024. Load will be transferred to Copeland TS upon completion of Phase 2.

[24] See Exhibit 2B, Sections D2.3, D3.3.1, and C3.3

Windsor	*A13-14WR*	2017	2023, 2024	Re-evaluation of load forecast indicated that relief is not required until 2024. Load will be transferred to Copeland TS upon completion of Phase 2.

In order to transfer load from one station to another, Toronto Hydro often needs to install new feeders at stations with spare capacity. These stations are either existing ones with switchgear that have available capacity and feeder positions, or new stations where switchgear will be installed to create additional capacity. New civil infrastructure will be required if the existing infrastructure is in poor condition and requires rebuilding or if there are insufficient ducts to accommodate the new feeder installation. Extensive cable pulling and splices[25] are then required to complete the transfer of customer loads from the existing feeders to the new feeders. Load can also be transferred from one station to another by extending existing feeders to feeders with available capacity. However, in the Horseshoe distribution area, loads can alternatively be transferred by installing new switches or relocating existing switches.

2. Feeder Level Load Transfers and Upgrades

Asset failures (overhead conductors, underground cables, and civil infrastructure) can lead to outages that last over an hour due to the time it takes for crews to switch customers from faulted feeders to standby supplies. In first contingency scenarios, the distribution system is designed to continue operating at or below rated capacity in order to facilitate the transfer of load from feeders under a faulted condition to standby feeders. This allows for the restoration of power to affected customers from the standby feeder while the faulted feeder is being repaired. If feeder capacity is constrained, the number of customers able to be served by the standby supply may be limited, which adversely impacts reliability as those customers that cannot be served by the standby supply would experience lengthy service interruptions. Having available capacity on adjacent feeders in addition to having available standby feeders allows for quicker restoration in the circumstances of a more catastrophic, multiple contingency event, because more operational options will be available to restore customers.

However, when the load on a faulted feeder exceeds the available rated capacity of standby feeders, restoration of power to affected customers is not possible until repairs are completed and, as a

[25] A splice is a joint created to maintain the connectivity between two cable sections or cable types. It is typically carried out when a longer cable is required, a branch is required or part of an old cable is replaced with a new cable.

result, such customers would be at risk of prolonged interruptions. For example, in the overhead system, when a feeder faults and its standby feeder ties cannot be used due to the risk of overloading, the affected customers on the faulted feeder would remain without power until the failure is completely addressed. In addition to the expected reliability improvement, having the flexibility to de-energize feeders improves Toronto Hydro's ability to execute planned capital and maintenance work by enabling the utility to switch customers onto their standby feeders. Toronto Hydro analyzed the reliability on 5 feeders in the Horseshoe area before and after their upgrades between 2010 and 2017. The results of this demonstrate that addressing feeder capacity constraints through upgrades and relief reduces the impact and duration of outage events, as seen in Table 7.

Table 7: Impact of Outages due to Feeder Capacity Constraints before and after the Upgrade

Measure	Before Upgrade/Relief	After Upgrade/Relief
SAIFI	0.008	0.007
SAIDI	0.436	0.172
Customers Interrupted ("CI")	5,384	2,561
Customer Minutes Out ("CMO")	305,987	74,309

When new customers are connected to the distribution system in areas of growth, Toronto Hydro also aims to enhance the capacity of the system. In doing so, it utilizes analytical strategies and tools to evaluate how customers are supplied, optimize the use of existing capacity, and accommodate new customers efficiently. This analysis helps to determine areas requiring feeder level transfers to enable available capacity. In some instances, the utility may decide to perform feeder level load transfers if the cables are already at the maximum size, if the legacy ducts are too small to accommodate the latest cable standards, or if the bus that supplies the feeder has available capacity.

Performing a load transfer between feeders to accommodate a new customer is often the preferred alternative when possible as it can be carried out at a lower cost than upgrading the feeder. Feeder level load transfers are also performed to help relieve bus loading, where possible, and to rearrange load in station areas where there is expected growth. Similar to bus level load transfers, feeder level upgrades and load transfers provide value to current and future customers by ensuring that the system can support rapid growth in a timely and cost-efficient manner, without adversely affecting the quality of service for existing customers. Each planned feeder level transfer is expected to relieve approximately 2 MVA of load. This allows capacity for additional growth on the feeder that is equivalent to accommodating approximately 1,000 new residential customers. The additional 2 MVA accounts for approximately 25 percent of a downtown feeder's capacity, which is consistent with the improvement seen from a typical downtown cable upgrade targeted in this Program.

The sections that follow describe the load transfer work planned on the 27.6 kV system, which serves the area of the system commonly known as the Horseshoe and the work planned for the 13.8 kV system, which serves the downtown core.

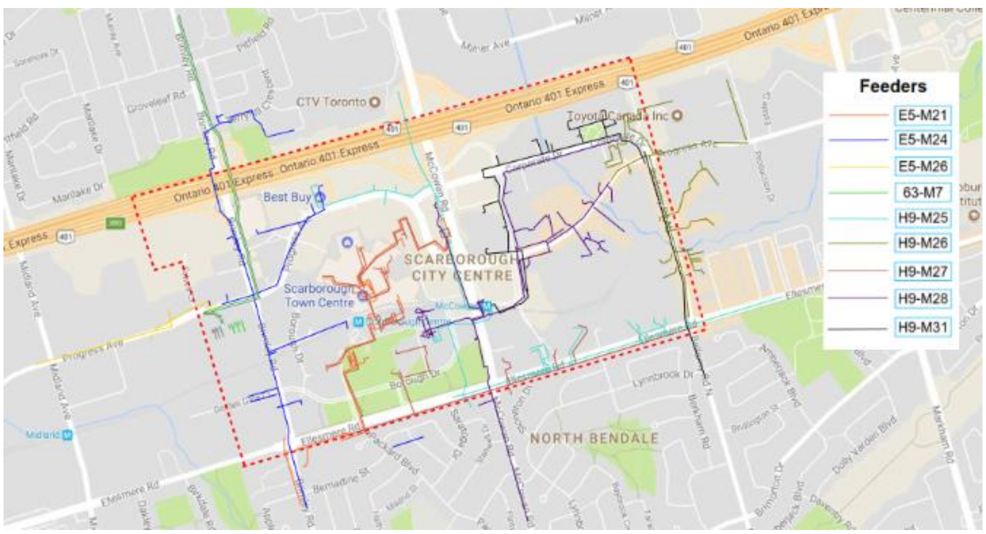
a. The Horseshoe System

The Horseshoe system is arranged in a looped configuration, with feeders tied via switches so that load can be transferred from one feeder to an adjacent feeder during contingency scenarios when a feeder is interrupted. Over time, growth can cause the load to exceed feeder capacity, which can lead to longer outages for customers in the event of a failure. For example, when a feeder experiences a fault, a standby feeder with sufficient capacity should be available to accommodate the customer load on the faulted feeder. If this capacity isn't available, only some sections on the faulted feeder can be restored, thus increasing the time needed to restore service to all affected customers. Similarly, the lack of back-up capacity can lead to challenges, and possibly unnecessary outages for customers, when performing planned maintenance or construction activities as mentioned above.

To manage load growth in the Horseshoe, Toronto Hydro plans to undertake capital investments in feeder level load transfers in the areas surrounding Scarborough Centre, Etobicoke Centre, and North York Centre. Figure 5, Figure 6, and Figure 7 show the Horseshoe feeders in these growth areas, respectively. The projected growth in these centres indicate the need to relieve highly loaded feeders in the area. In these areas, it is estimated that feeders 38M7, 80M28, 80M30, 80M5, E5-1M28 and H9M26 will require relief as they are currently at capacity under first contingency. In total, these feeders serve 12,299 customers, and on average, each of these feeders has 1849 residential customers and 201 commercial customers, for a total of 2050 customers as seen in Table 8. Load transfers are preferred over feeder upgrades because the overhead system, which serves the Horseshoe area, has multiple tie switches making it easier and more cost-effective to transfer load between adjacent feeders thus supporting Horseshoe customer priorities.

1 **Table 8: Horseshoe Feeders Targeted for Relief**

Feeder	Residential	Commercial up to 1MW	Commercial >1MW	Total
38M7	2,896	247	0	**3,143**
51M28	397	24	2	**423**
80M28	607	72	5	**684**
80M30	2,325	75	2	**2,402**
80M5	3,909	377	2	**4,288**
H9M26	962	397	0	**1,359**
Averages	**1,849**	**199**	**2**	**2,050**
Totals	**11,096**	**1192**	**11**	**12,299**



2 **Figure 5: Horseshoe Feeders in the Scarborough Centre**

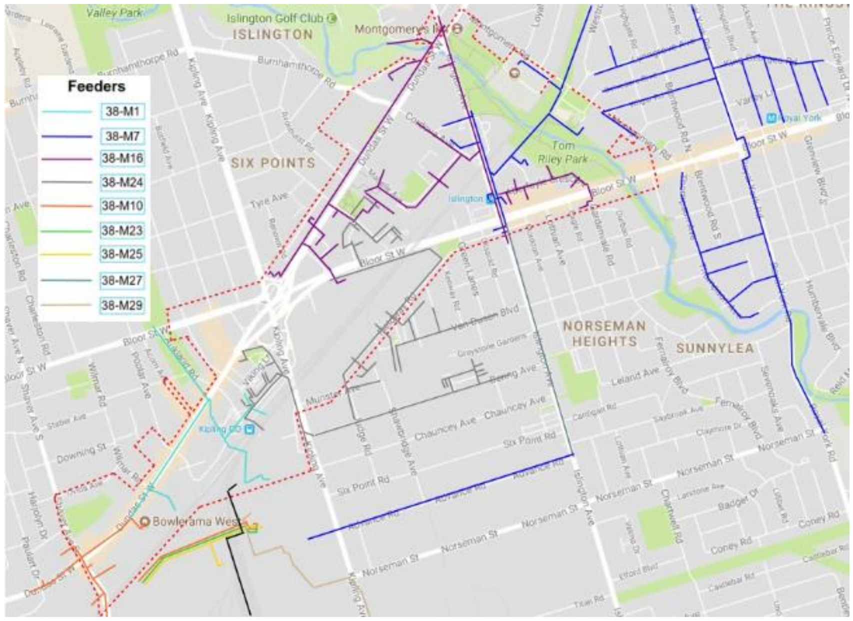


Figure 6: Horseshoe Feeders in the Etobicoke Centre

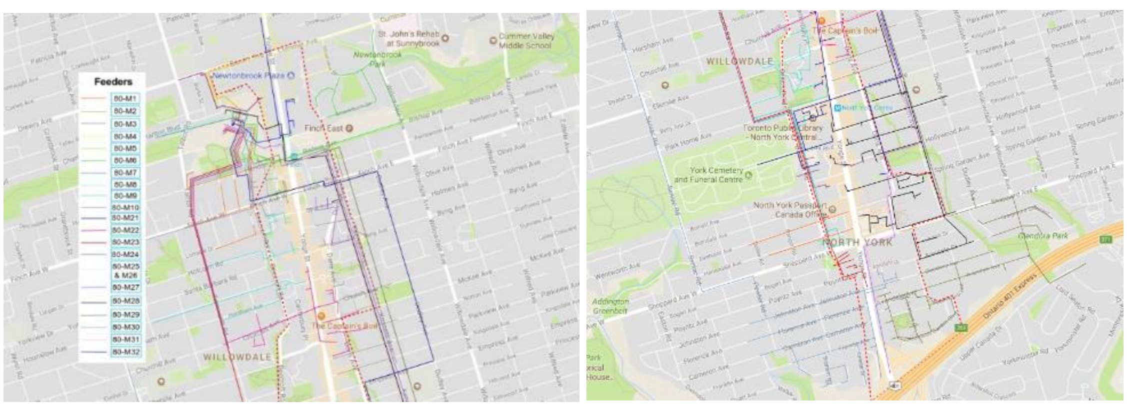


Figure 7: Horseshoe Feeders in the North York Centre

b. <u>The Downtown System</u>

The majority of the underground 13.8 kV system in downtown Toronto is configured as a dual radial scheme. Customers are supplied by two feeders: one that provides their normal supply and the other that operates as standby supply. In areas that have experienced rapid load growth, customers now have an overloaded standby supply, with additional overloaded feeders expected during the 2020-2024 period. To address this issue, Toronto Hydro plans to upgrade primary cables or perform load transfers.

Toronto Hydro analyzed all downtown feeders to determine which feeders are projected to be highly loaded during the 2020-2024 period based on natural load growth and customer connection forecasts. By the end of 2019, Toronto Hydro expects to have 35 highly loaded feeders in the downtown system. Over the 2020-2024 period, there will be 24 new highly loaded downtown feeders in danger of being overloaded under contingency, resulting in 59 highly loaded feeders of the total 843 feeders in the downtown system if no work is done to address them.

As a result, in the 2020-2024 period, Toronto Hydro plans to relieve 28 feeders in the downtown area to manage load growth, including 18 feeder upgrades, and 10 feeder load transfers. The 28 feeders planned for relief at the time of relief will be highly loaded feeders that limit growth and operational flexibility. By comparison, in the 2015-2019 period, Toronto Hydro relieved 25 highly loaded feeders through cable upgrades and cable transfers. The specific feeder upgrades to be completed will depend on where load materializes in the system. On average, each feeder targeted for upgrade or transfer has 111 residential customers, and 7 commercial customers, for a total of 118 customers.

Toronto Hydro plans to upgrade undersized feeder trunks to the current standard (500 kcmil TRXLPE) to utilize previously stranded capacity for feeders that are becoming highly loaded. For example, feeder A94A supplies 12 customers in and around the downtown core, including Sick Kids Hospital courtyard, and customers around the Toronto Eaton Centre and Dundas Square. This feeder is at capacity due to the presence of undersized 2/0 trunk cable. An upgrade to 500 kcmil TRXLPE cable will more than double the capacity on the feeder, allowing for 5 MVA of customer load to be added.

In the downtown area, because of congested civil infrastructure nearing end of life or built to older standards (therefore unable to accommodate the latest standards), it is often necessary to rebuild or expand the existing civil infrastructure when upgrading underground cables. Figure 8 below shows a congested legacy square duct unable to accommodate the current standard trunk cable, therefore limiting the overall capacity of feeders using this civil route. Toronto Hydro plans to complete upgrades or rebuilds of this existing civil plant as part of this Program. It is estimated that 50 percent of the length of the civil route for each planned upgraded feeder will need to be upgraded as well to accommodate the new electrical. This includes cable chamber and ductbank rebuilds.

Figure 8: Example of a Legacy Square Clay Tile Duct

New feeder installations are also required when an area needs more feeder capacity than is available with the existing feeders. For example, express tie feeders must be upgraded or new ties must be installed to realize the full capacity of the infrastructure. Express tie feeders exist when there is not enough physical space in a station to house both the Hydro One transformer and switchgears. In these scenarios, there is a Hydro One transformer at one station supplying the switchgear at another station via express tie feeders. These feeders do not service any other load. In the 2020-2024 period, a new express tie feeder between Bridgman TS and High Level TS is proposed to relieve the capacity constraints on the A5-6H bus. This investment will increase the capacity at the A5-6H bus by 24 MVA, creating capacity to service that is equivalent to 12,000 new residential customers in the area.

3. Network Equipment Upgrades

Due to capacity constraints, Toronto Hydro is forced to impose summer switching restrictions during peak load conditions, such that certain feeders cannot be taken out of service during those periods. If restricted feeders are taken out of service, their corresponding standby infrastructure (standby feeders, adjacent network units) will be overloaded. This practice constrains Toronto Hydro's ability to complete new customer connections and hinders its ability to plan and execute other capital maintenance work in a timely and efficient manner.

Heat restricted feeders are feeders flagged as at-risk of overloading their standby feeders or network equipment during a contingency situation during peak hours or summer days. This means that these feeders should not be taken out of service (at a certain temperature) in the summer months in order to avoid overloading other infrastructure under contingency. Toronto Hydro is seeking to reduce the number of restrictions on its system so as to enhance its ability to take feeders out of service for maintenance or capital work. Cable upgrades and load transfers may be used as strategies to relieve summer switching restrictions on the primary feeder level. The network equipment upgrades as part of the Load Demand program aim to remove restrictions caused by undersized network units. An example of a network unit is shown in Figure 9. A network unit consists of a primary switch, network transformer, and network protector.

Figure 9: An Example 500 kVA Network Unit

In the downtown core, network units are fed from various feeders interconnected on the secondary side (i.e. low voltage) of the distribution transformer in order to provide a redundant and highly reliable supply to customers. This configuration reduces the risk of customers experiencing momentary interruptions during single contingency events. The network system supports reliability for customers in the downtown area, highlighted as a priority through customer engagement.

Current key customers on the network system include Sick Kids Hospital, Sheraton Centre, Bell Canada, and the Ontario Power Building.

Through network equipment upgrades, Toronto Hydro will improve reliability for downtown customers on the network, highlighted as a priority in the customer engagement. This will be done by reducing the number of potential network unit failures due to overloads; increasing the robustness of the network units by introducing the submersible design; and improving the amount of first contingency scenarios supported by reducing feeder restrictions. Network equipment that is at or over capacity must be upgraded to ensure that the network system operates without overloading. Overloading the network equipment can result in premature deterioration and failure of the assets, which in turn drives the need to impose restrictions during peak summer months. An additional benefit of upgrading existing overloaded network equipment is the introduction of a more robust submersible design that is capable of operating under flooded conditions. In locations where an upgrade is not possible because the network units are already at the highest size or if there are civil limitations, an additional transformer in a new vault may be installed or additional secondary cables may be added to support the highly loaded vaults.

In the 2015-2019 CIR application, Toronto Hydro indicated its goal of reducing the number of summer switching restrictions and has been doing so accordingly as seen in its progress presented in Table 9 below.

Table 9: Summer Restrictions by Year

Summer Restrictions	Year				
	2013	2014	2015	2016	2017
Number of Feeders Restricted	60	54	49	43	21

By the end of 2019, there are projected to be 7 restrictions remaining, and the growth on the network is expected to overload 8 more network units under contingency by the end of 2024,[26] for a total of 15 restrictions. Toronto Hydro's goal is to reduce the total number of restrictions to below 10 by the end of 2024. To achieve this goal, the utility must perform at least 6 network equipment upgrades during the 2020-2024 period, while mitigating any potential primary feeder restrictions via cable upgrades and load transfers.

[26] The peak load reading of each network unit in the system was taken over the last 5 years and a growth consistent with the Metro Toronto Regional Infrastructure Plan was added to forecast the future overloads.

4. Civil Enhancements

When certain stations are expanded or their switchgear is upgraded, Toronto Hydro must undertake supporting civil enhancement work in the egress cable chambers to enable additional capacity at the station. However, the total capacity of the station bus can be limited by other factors, such as the capacity of the Hydro One transformers supplying the station buses. Table 10 summarizes the expected station upgrades within the 2020-2024 period that will require civil egress rebuilds in order to optimally serve customers. These areas are shown geographically in Figure 10.

Table 10: Stations Requiring Civil Egress Rebuilds

Station	Associated Work	Target Year
Carlaw TS	*Switchgear Renewal*[27]	2021, 2022
Horner TS	*Station Expansion*[28]	2022, 2023
High Level TS	*Switchgear Renewal*[29]	2024, 2025

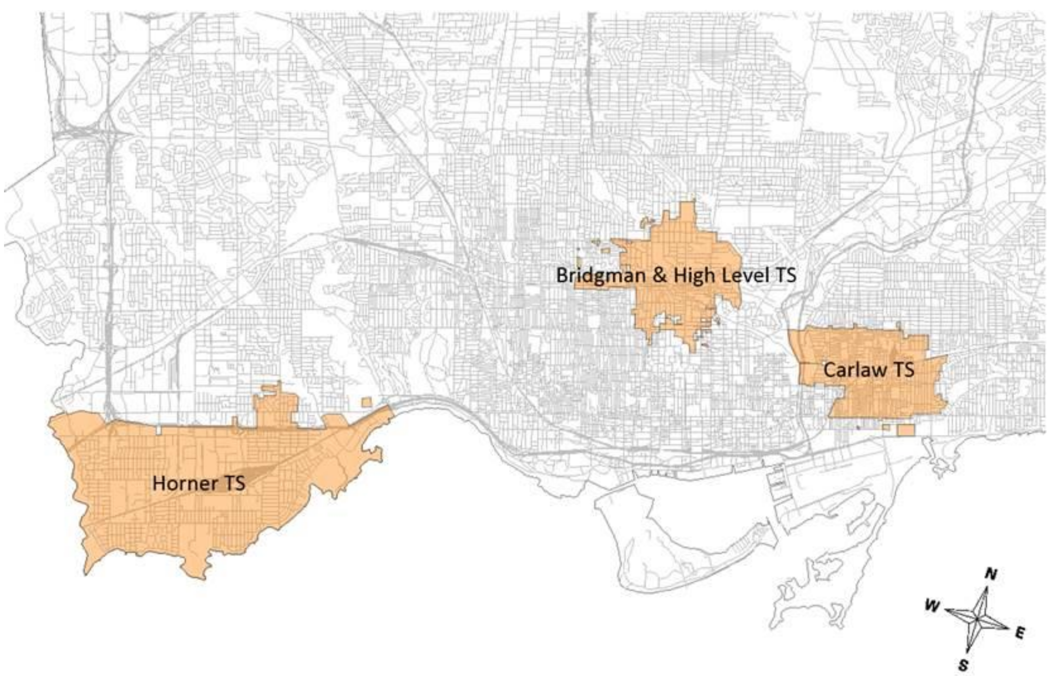


Figure 10: Stations Targeted for Civil Enhancements during the 2020-2024 Period

[27] See Exhibit 2B, Schedule E6.6 – Stations Renewal
[28] See Exhibit 2B, Schedule E7.4 – Stations Expansion
[29] *Supra* note 26

The egress cable chambers at the targeted stations are highly congested, limiting the number of feeders and their directional configurations when exiting the station. The result is that if new feeders are required to serve customers in these areas, it may not be possible to use the shortest optimal route from the station. A longer route may need to be used or a new civil route may need to be constructed, resulting in additional costs to the customer and time to complete the connection work. For example, after the Carlaw TS switchgear renewal, there will be a new switchgear at the northeast corner of the station, egressing through the north cable pit. The majority of the Carlaw feeders already run north and northeast and those that are needed to the south must utilize cable chambers around the station to run south. This creates congestion around the station, as evidenced by the fact that cable chambers 1220, 1107, 1108, and 8285 have over 9 or more feeders running through them. With plans to relieve Basin in the 2020-2024 period[30] (see Table 5), to the south of Carlaw, additional feeders will need to be pulled south and the civil infrastructure must be upgraded and arranged in order to accommodate these plans. If the feeders to relieve Basin cannot be pulled, rapid growth in the Basin areas (such as Ashbridge's Bay), GO Transit and the Portlands development, will overload Basin buses.

Apart from the capacity limitations, congested cable chambers increase the potential impact of chamber collapse on multiple feeders (and the significant customer load they supply in aggregate). For example, a cable chamber of 15 feeders can account for up to 75 MVA of customer load. Congested cable chambers also significantly impede the crews' execution ability given the practical difficulty of performing work within such chambers.

E5.3.4 Expenditure Plan

Table 11: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Load Demand	9.9	16.8	16.2	17.3	21.6	11.3	11.4	18.5	22.6	23.6

[30] Toronto Hydro plans to provide additional relief to Basin TS through Local Demand Response in the 2020-2024 period. See Exhibit 2B, Schedule 7.4 Stations Expansion for more details.

Table 12: Program Costs ($ Millions)

Type of Work	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Load Transfers	4.7	1.9	8.7	4.1	3.4	4.3	1.4	5.5	10.3	8.3
Cable Upgrades	1.7	5.5	2.5	1.2	10.6	6.6	6.8	6.9	9.3	11.9
Equipment Upgrades	0.01	2	0.5	2.6	2.6	0.4	0.2	0.2	0.2	0.2
Civil Enhancements	3.5	7.4	4.5	9.4	5	0.0	3.0	5.9	2.8	3.2

The 2020-2024 expenditure plan is based on the specific work that is planned in each year. As is true with the 2015-2019 period, expenditures vary considerably from one year to the next due to the volume of work associated with the different activities undertaken by the Load Demand program (i.e. load transfers, cable and equipment upgrades, and civil enhancements).

During 2015-2017, Toronto Hydro has relieved capacity constraints on the system through the:

- Alleviation of 10 highly loaded buses through bus level load transfers and by creating new feeder positions;
- Reduction in the amount of highly loaded feeders by 25 through feeder level transfers and feeder upgrades;
- Improvement to the civil egress of George & Duke MS, Runnymede TS, Richview TS and Copeland TS, which enabled additional feeders to make use of the full capacity of the station; and
- Reduction of summer switching feeder restrictions by 28 between 2015 and 2017, with an additional 14 feeder restrictions expected to be eliminated by 2019.

These forecasts are re-evaluated annually, as described in the DSP – Capacity Planning,[31] driven by information on expected new connections, on expected load transfers and voltage conversions, re-evaluated growth rate, and the previous years' weather corrected peak which is used as base for load growth. Based on the annual re-evaluation of station bus load forecasts, Toronto Hydro fully expects that project scheduling will change. This is natural for a program such as Load Demand.

Investments in the 2020-2024 period aim to continue to relieve capacity strained areas in the City of Toronto. The plans are based on 2017 load forecast. As described in section E5.3.3, this Program is

[31] Exhibit 2B, Section D2.3, 3.2.1, and C3.3

made up of investments in station bus load transfer, feeder level load transfers and upgrades, network equipment upgrades and civil egress enhancements.

E5.3.4.1 Station Bus Load Transfers

The proposed work aims to provide load relief to the station buses that are expected to become overloaded in the next rate period due to growth, and which are located in areas where capacity is available at an adjacent station. Some of the planned bus load transfers are dependent on the completion of station expansions projects, such as the Copeland TS Phase 2 project,[32] which will allow Toronto Hydro to provide relief to the buses at Strachan TS, Windsor TS, and Esplanade TS.

The costs for bus level load transfers were forecasted using a cost per MVA transferred value. The cost per MVA can vary greatly for a bus level load transfer, depending on distance between stations involved in the transfer, location of feeders, and geographical constraints, such as the presence of bridges and highways, and civil conditions. Nonetheless, the average cost was derived based on projects from 2015 to 2019 to provide a best possible estimate of future project costs. Further, the per MVA unit costs were separately determined for the following three types of work (as mentioned in section E5.3.3.1 sub-section 1) so as to account for their considerable differences:

- **Downtown (Intra-station) Transfers**: $0.15 million per MVA.
- **Downtown (Inter-station) Transfers**: $0.25 million per MVA.
- **Load Transfers in the Horseshoe area:** $0.08 million per MVA.

Intrastation transfers in the downtown area are less costly than transfers between stations (interstation) because the amount of cabling and civil work required to bring load from different station areas is greater than transferring within the same station area.

Load transfers in the Horseshoe area, which is generally served by the overhead system, are less costly because the transfers can be completed by installing opening, and closing tie switches between feeders. In areas where a transfer is needed but switches do not exist, the cost to install switches and any additional overhead conductors is much lower than the underground feeder extensions and splices that are required for transfers in the downtown area.

[32] Exhibit 2B, Section 7.4 Stations Expansion

E5.3.4.2 Feeder Level Load Transfers and Upgrades

As noted above, Toronto Hydro plans to undertake 18 feeder upgrades and conduct 10 feeder load transfers in the downtown area during the 2020-2024 period. In the Horseshoe system, the utility plans to perform 6 feeder load transfers in the Etobicoke, North York and Scarborough growth centers. This involves transferring load to adjacent feeders via overhead tie switches. The unit costs for feeder level load transfers in the downtown area and in the Horseshoe area are $0.5 million per feeder and $0.15 million per feeder, respectively.

Any cable upgrade to the trunk of a downtown feeder is estimated to upgrade 1,000 meters of cable, which will include civil upgrades for half of the distance. This amounts to 500 meters of duct banks, 10 cable chambers, and 10 splices. The unit cost assumes 1,000 meters of upgrades per targeted feeder because this is the average length of a feeder trunk, with each downtown feeder having a maximum spread of approximately 3,000 meters.

E5.3.4.3 Network Equipment Upgrades

Toronto Hydro plans to complete 6 network equipment upgrades during the 2020-2024 period in order to achieve its target of limiting summer switching restrictions under contingency scenarios to under 10.

For network equipment upgrades, the per unit cost was based on the cost to remove and install a new 750 kVA network unit, which was the most common upgrade seen in the 2015-2019 period. Furthermore, the per unit cost aligns with the average cost of replacing network units in 2017. The cost used for forecasting is $0.17 million per unit upgrade.

E5.3.4.4 Civil Egress Enhancements

Toronto Hydro plans to rebuild the civil egress cable chambers at Carlaw TS (downtown), Horner TS (Horseshoe) and High Level TS (downtown). The cost per station was forecasted based on historical projects in the downtown and Horseshoe areas, $5 million, and $4.5 million respectively.

E5.3.4.5 Project Prioritization

Toronto Hydro considers a combination of several factors when prioritizing projects within the Load Demand program, including:

- **Capacity to connect new customers:** Toronto Hydro addresses areas of the system that are at capacity and that require significant investments to allow the connection of new customers. The lack of forecasted capacity in the short-term is what ultimately triggers projects within this Program.
- **Single contingency operation:** Current limitations on the system prevent overloading during contingency operations. Projects that introduce additional capacity to allow the operators to remove these limitations will receive a higher priority.
- **Reliability:** For load transfer projects, sections of cable that require upgrading and that are on feeders with poor reliability or adjacent feeders will be given higher priority in order to improve future outage restoration times.

E5.3.4.6 Cost Management

Load Demand projects are continuously evaluated to ensure that the spending is in the appropriate areas. For example, the need for each bus level load transfer is re-evaluated annually to see if forecasts still hold true or should be modified. Load forecasts are the basis for determining if buses require relief. As seen in Table 8 above, a number of buses that were expected to be overloaded in the 2015-2019 period were deferred to 2020-2024. This allowed for other Load Demand work to be completed in their place since the transfers identified in Table 8 were no longer immediately required.

By making capacity available by both electrical relief (via bus transfers, feeder transfers, feeder upgrades and equipment upgrades), and civil relief (via station enhancements), customers are able to be connected in an efficient manner. Without available capacity, infrastructure may have to be built using a suboptimal station (i.e. not in the area of the customer(s)) and using suboptimal and lengthy routes. Avoiding this work reduces the utility's cost of connecting customers.

E5.3.5 Options Analysis

E5.3.5.1 Option 1: Do Nothing

Option 1 entails not planning any load transfers, equipment upgrades, or civil enhancements. This option allows Toronto Hydro to defer capital spending. Toronto Hydro anticipates that this option would reduce reliability and increase failure risk. Increasing loading stress on existing electrical infrastructure in heavily loaded areas under first contingency would shorten the operational life time of the electrical infrastructure. Rolling blackouts may be required during the summer to ensure that the peak loading remains under the capacity for the system, since no investments are being made to resolve the overloads during summer peaks. Areas of heavy loading will continue to experience increased loading, with the capacity to transfer loads under contingency decreasing. Following this option would impair the utility's ability to expedite upgrades to relieve heavily loaded infrastructure effectively and efficiently.

The addition of new high load customers in identified heavily loaded areas may exceed first contingency capacity, making system upgrades increasingly difficult and lengthy as Toronto Hydro would be unable to take feeders out of service for planned work if there is no viable standby feeder to accept the load. Finally, the exposure risk of customers in highly loaded areas to lengthy outages due to equipment failures or severe weather will be higher because of the inability to transfer load to standby or alternate supplies if capacity constraints are violated.

This is not a feasible option as it would give rise to a risk of non-compliance with DSC sections 3.3.1 and 4.4.1, which require Toronto Hydro to prudently and efficiently manage its distribution system, and address forecast load growth.

E5.3.5.2 Option 2: Upgrade Station Capacity

Under Option 2, Toronto Hydro would add station capacity through expansion of existing stations or construction of new stations in the heavily loaded areas where there is a projected influx of new development. This would build a large amount of capacity into the system.

However, this alternative would require a large capital investment spread over multiple years, detailed studies for optimal location (greatest load impact), environmental assessments, drawn-out construction times plus the subsequent work required to distribute the newly created surplus around the grid. This would take eight to ten years to complete which would not address the issues arising in the 2020-2024 period. As a result, this timeline would expose customers in existing high load growth areas to potentially lengthy outages. These outages would result from the inability to restore customers on standby feeders exceeding capacity constraints, and on overloaded equipment resulting in failures. Finally, this option would not make use of existing stranded station capacity that could be made available by load transfers.

Option 2 thus involves long term projects and cannot meet emerging capacity needs in the short to medium-term. Therefore, it would not be prudent to carry out this option.

E5.3.5.3 Option 3 (Selected Option): Upgrade equipment, civil infrastructure and perform load transfers, as per the Load Demand program

The preferred option is to upgrade equipment and infrastructure in highly loaded and congested areas of the system and in areas of proposed high load developments with a focus on relieving overloads under a first contingency basis. It provides capacity for increased loading in heavily loaded areas that are already at maximum capacity, and enables first contingency load transfers in areas of heavy loading that show trending of load increase, which would otherwise exceed present capacity to transfer loads under contingency. As a result, the Program reduces exposure risk and outage durations for customers in identified high load areas resulting from equipment failures or storms.

This option provides capacity to expedite future upgrades and balance system loading, makes use of existing system assets by performing load transfers between highly loaded buses and feeders to lightly loaded alternatives, and allows Toronto Hydro to maintain full compliance with DSC sections 3.3.1 and 4.4.1 with regard to prudent and efficient distribution system management.

However, this alternative requires capital investment to upgrade existing or install new assets. The new assets would be less costly than Option 2, and less than Option 4.

This is the preferred option since it addresses the capacity needs of the distribution system that are arising in the short to medium term. With this option, Toronto Hydro can comply with the Distribution System Code and improve customer service, reliability, and safety of the system.

E5.3.5.4 Option 4: Upgrade all feeder cables, and alleviate all highly loaded buses and feeders

Under this option, in addition to the feeder cables, feeder and bus load transfers to be addressed through Option 3, Toronto Hydro would address the remaining 31 highly loaded downtown feeders identified as being less urgent as those addressed under Option 3. This option would allow for extensive relief on the remaining highly loaded feeders, and therefore increase the capacity on the distribution system to connect customers and ensure system reliability. However, when feeders do not have adjacent feeders with available capacity, the cost of relieving the targeted feeders increases.

At an estimated $130 million, Toronto Hydro determined that this option would be too costly in light of other investment priorities.

E5.3.6 Execution Risks & Mitigation

Several issues can present risks to the execution of the Load Demand program. These include the addition of loads or redevelopment of an area with dated or lacking civil infrastructure, road moratoriums and difficulties coordinating with third party utilities.

In order to complete load transfers and cable upgrades, feeders may need to be pulled or upgraded over long distances (up to 3 kilometres) where voltage drop issues start becoming a concern, utilizing several cable chambers and duct banks along the route. Records provide an indication of what civil costs can be expected for a Load Demand project; however, there can be unexpected rebuilding or expansion of civil infrastructure that is required. Civil inspections performed earlier in the project cycle can help mitigate any unforeseen project costs.

Moratoriums and third party construction can limit and dictate the civil routes used in load transfers. Costlier solutions to bring capacity into an area may be required because we are unable to utilize more optimal routes where moratoriums exist or third party construction is taking place. In these cases, potential impacts must be identified at the early stages of project planning and coordination must be sought and achieved.

5.4 Metering

E5.4.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 105.9	**2020-2024 Cost ($M)**: 130.8
Segments: Revenue Metering Compliance; and Wholesale Metering Compliance	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Service, Public Policy, Financial , Reliability	

The Metering program (the "Program") funds investments in the utility's metering technology to ensure the reliable measurement of electricity acquired by the utility through the provincial transmission system and distributed to its customers. The Program consists of two segments: Wholesale Meter Compliance and Revenue Meter Compliance. The Wholesale Meter Compliance ("WMC") segment involves the maintenance and replacement of wholesale meters at transmission supply points. This segment ensures that Toronto Hydro remains compliant with IESO Market Rules pertaining to the Wholesale Market. The Revenue Meter Compliance ("RMC") segment involves the installation of meters for new customers, replacement of faulty or expired meters, and maintenance and upgrades of supporting metering infrastructure. The segment is comprised of specific initiatives that impact all of Toronto Hydro's customers from residential customers to large users. A substantial part of this segment involves the planned replacement of Toronto Hydro's population of first generation residential and small commercial smart meters, many of which will have expired seals and have been in the field beyond their expected useful life during the 2020-2024 plan period. The Program and its constituent segments are a continuation of the activities described in the Metering program in Toronto Hydro's 2015-2019 Rate Application.[1]

The Program's primary objective is to maintain compliance with legal and regulatory metering requirements under the *Electricity and Gas Inspection Act*, the *Weights and Measures Act*, and the IESO's Market Rules. In addition, the investments in this Program facilitate accurate customer billing, enhance Toronto Hydro's ability to monitor the distribution system, respond to outages, and support the utility's financial operations.

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 2B, Tab 8, Schedule 1, Section E5.1.

E5.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Maintaining billing accuracy of at least 98 percent by: (i) upgrading and replacing metering infrastructure and limiting the percentage of meters past their useful life; (ii) completing metering system upgrade initiatives that reduce estimated bills and bill corrections; and (iii) implementing a Mobile Workforce Management program to reduce the number of estimated bills due to meter changes; and ○ Installing ION meters so that customers can monitor energy consumption and power quality in real-time.
Reliability	• Contributes to Toronto Hydro's reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by installing new meters with Last Gasp Functionality enabling Power System Controllers to more effectively direct field crews. This also enables emergency response and outage restoration activities that require customer level outage information.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Maintaining compliance with various requirements such as Measurement Canada's *Electricity and Gas Inspection Act* and Regulations, and the IESO's Market Rules to enable accurate and timely meter reading, billing and market settlements; ○ Enabling Toronto Hydro to respond more efficiently to changes in Distribution Licence conditions related to customer disconnections with remote disconnect and reconnect meters; and ○ Enabling the full implementation of customer specific reliability measures currently being piloted by the OEB, and contemplated under the Long-Term Energy Plan 2017[2] by installing new meters with Last Gasp functionality.

[2] The Ontario Energy Board's Implementation Plan In response to the Minister of Energy's Directive in respect of the implementation of Ontario's Long-Term Energy Plan 2017: Delivering Fairness and Choice, page 7. https://www.oeb.ca/sites/default/files/OEB-LTEP-Implementation-Plan.pdf

Financial	• Contributes to Toronto Hydro's financial objectives by ensuring energy consumption, and purchase of wholesale energy is measured accurately and in a timely manner.

E5.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Failure Risk, Business Operations Efficiency

E5.4.3.1 Mandated Service Obligations

1. Wholesale Meter Compliance

Toronto Hydro plans to upgrade its wholesale revenue meters to comply with the metering standards mandated by Measurement Canada and the IESO Market Rules. Wholesale revenue metering upgrades require approved instrument transformers, de-registering the existing wholesale revenue metering points, preparing the site for new compliant wholesale metering equipment, and overseeing the wholesale revenue metering installation work, along with completing the registration process with the IESO. Toronto Hydro plans to undertake this work so that it can complete the scheduled metering point upgrades at all applicable wholesale metering points during the 2020-2024 plan period.

2. Revenue Metering Compliance

Measurement Canada has jurisdiction over the administration and enforcement of the *Weights and Measures Act*[3] and the *Electricity and Gas Inspection Act*.[4] These Acts and related regulations govern Toronto Hydro's ability to bill its customers for electricity usage, and require that all meters must be resealed at specified intervals to ensure that a customer's electricity usage is metered accurately. Once a seal expires, the meter cannot legally be used for billing purposes and must either have its seal period extended (via compliance testing), or be replaced.

For large homogenous batches of meters, Measurement Canada permits a sampling protocol to verify the accuracy of the meters. If the statistical accuracy results from the sample testing are within

[3] R.S.C., 1985, c. W-6.
[4] R.S.C., 1985, c. E-4.

acceptable levels, all the meters in the meter group will receive a seal extension. Certain meters need to be "re-verified." Re-verified meters are tested individually because they do not fit within the sampling program and are required by law to be removed for testing and replaced with new meters.

Once the seals of a meter group have expired, Toronto Hydro cannot use the meters in the group to bill its customers. The use of meters with expired seals could result in the incorrect billing of customers due to inaccurate meters. Also, in the event that the meters with expired seals remain in use, Toronto Hydro could face financial penalties, as contemplated by the *Electricity and Gas Inspection Act*.

All categories of meters (residential, commercial and industrial, large users, suite meters, wholesale meters) will need to have their seals extended or be replaced through either the sampling process or re-verification process throughout the 2020-2024 period. The bulk of residential and small commercial & industrial meters (which make up the significant majority of meters in Toronto Hydro's system) will have their seals expire in 2024. Please see Figure 1, below, for a breakdown of the number of meters with seals expiring by year.

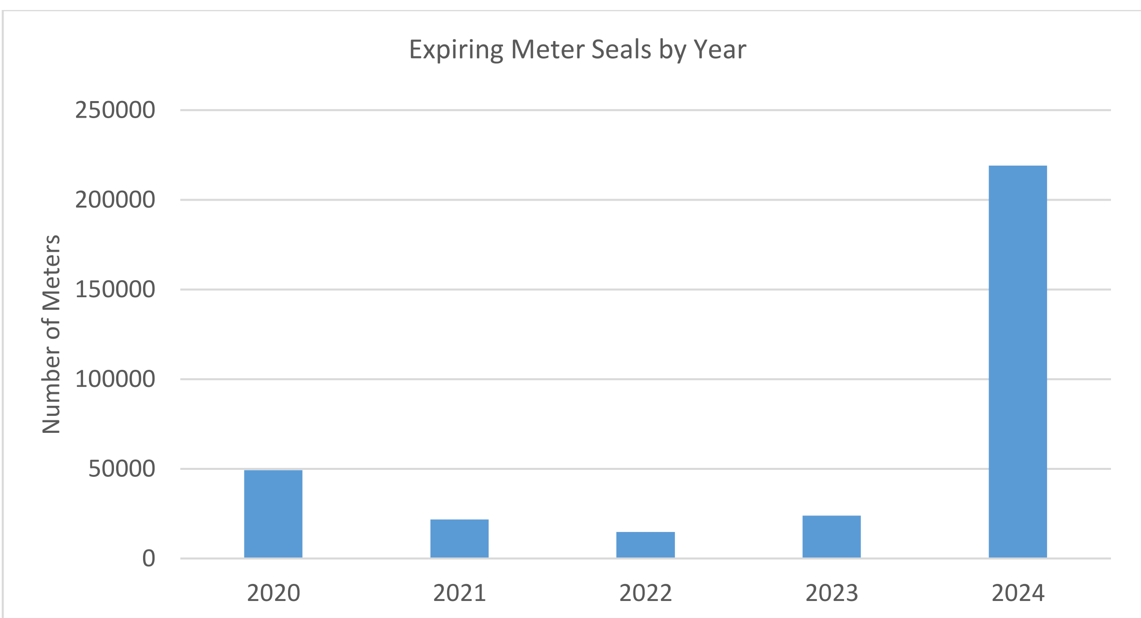


Figure 1: Expiring Meter Seals by Year

a. <u>Meter Re-verification and replacement for Large User Class</u>

Large User Class customers have average monthly demands of over one megawatt (1 MW). They represent only 0.06 percent of Toronto Hydro's customers, yet they generate approximately 13 percent of Toronto Hydro's total yearly revenue. These customers are typically key contributors to the economy of Toronto and Ontario, and can have loads that are sensitive to power quality. Examples of such customers may include auto manufacturers, office towers, entertainment complexes that host national and international entertainment and sporting events, hospitals, and industrial manufacturing plants with sensitive equipment.

Replacing meters currently in use by Large User Class customers at the time of meter re-verification with new ION meters that have added functionality will allow for the diagnosis of customer power quality issues, and could lead to a reduction in customer-specific power interruptions. In addition, these meters provide three-phase power quality information to Toronto Hydro that will be used to investigate distribution system issues related to power quality, in order to take preventative actions. These meters also provide direct benefits to the customers themselves by allowing them to monitor their energy consumption and power quality in real-time.

Figure 2: ION 8650 Meter Installed at Large User Sites

As the ION meters are only installed once the seal on the existing meter has expired, the ION meter implementation is staggered with the majority of the replacements having taken place between 2014 and 2017, see Figure 3, below. Going forward, Toronto Hydro will install new meters as customers meeting the Large User criteria are connected. Toronto Hydro will also have to replace and re-verify these meters as their meter seals expire. The planned ION installation schedule for 2020 to 2024 is also outlined in Figure 3, below.

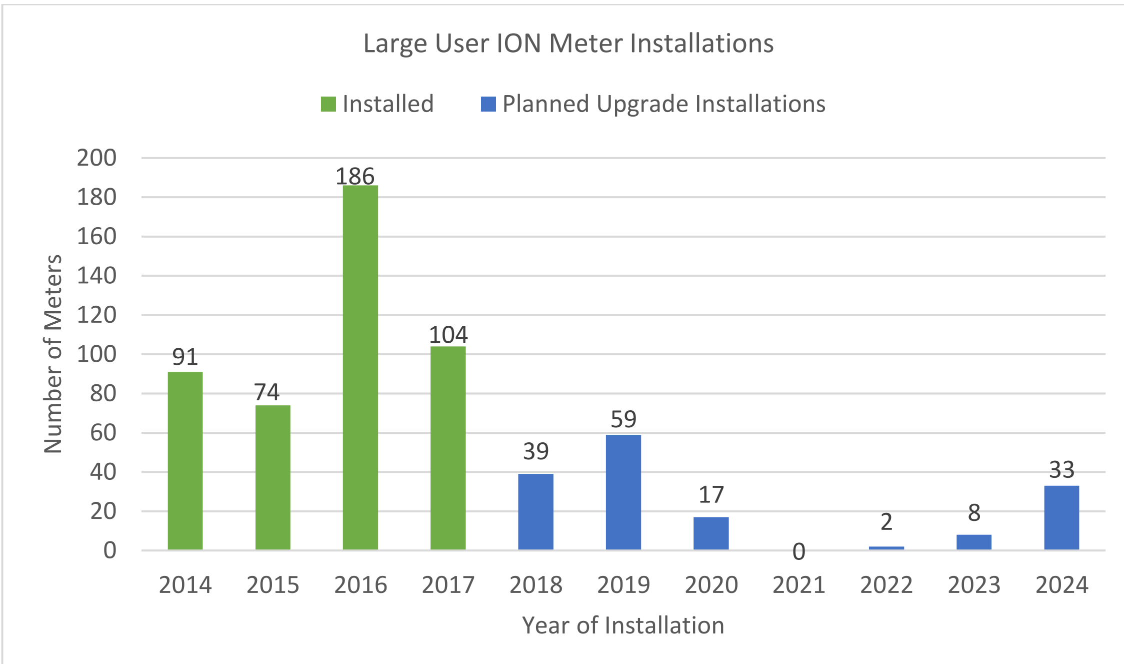


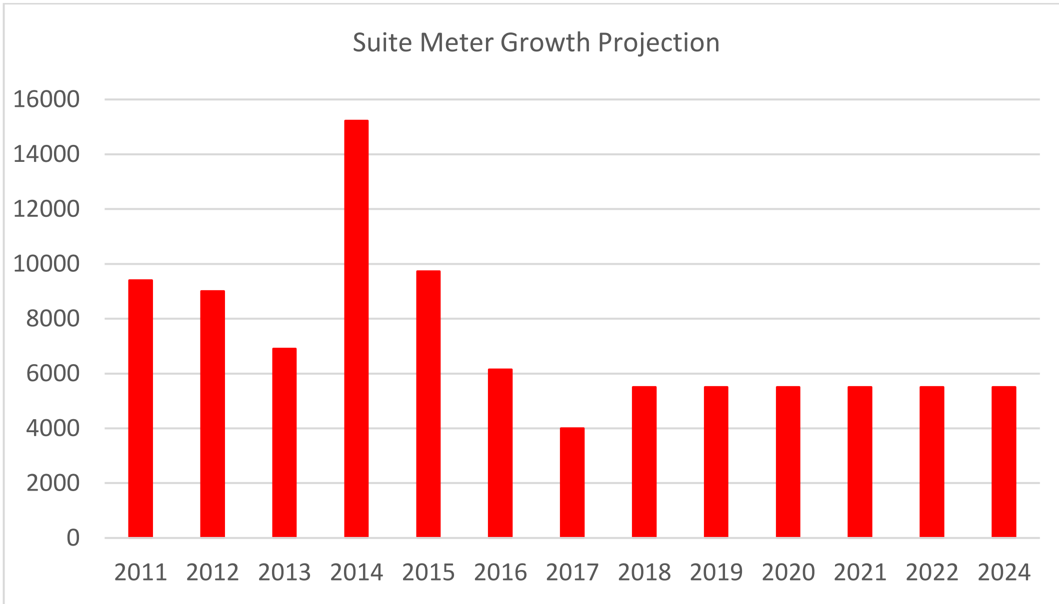
Figure 3: Large User ION Meter Installations by Year

b. <u>Suite Meter Installations</u>

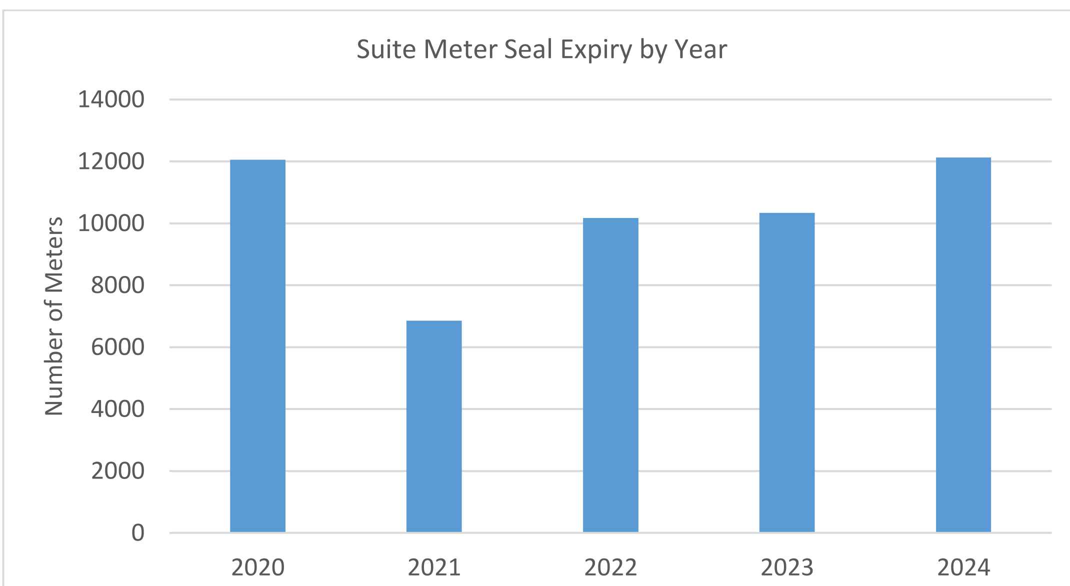
Toronto Hydro is legally obligated to provide suite meter installation service. Utilities like Toronto Hydro offer this service in a competitive environment, and are also providers of last resort in the event that the condominium chooses not to secure a third party meter service provider.

There are currently approximately 79,000 suites that are individually metered by Toronto Hydro and about 3,000 multi-residential buildings that are metered by one bulk meter.

Going forward, Toronto Hydro will continue to offer its suite metering services to new customers and retrofit upgrades with an expected growth of roughly 5,500 new units every year. See Figure 4, below, for a chart showing historic and projected suite metering growth. Toronto Hydro will also continue to maintain the existing population of installed suite meters (see Figure 5, below) by re-verifying and re-sealing the meters as required.



1 **Figure 4: Suite Meter Historical and Projected Growth**



2 **Figure 5: Suite Meter Seal Expiry by Year 2020-2024**

3 *c. <u>Continued Provincial Meter Data Management Repository ("MDM/R") Integration</u>*

4 Toronto Hydro's billing systems will be fully integrated with the *Provincial* Meter Data Management
5 Repository *("*MDM/R") by the end of the 2015-2019 period. During the 2020-2024 plan period, the

IESO is anticipated to have a mandatory upgrade and Toronto Hydro will have to ensure that the new upgrade will communicate successfully with Toronto Hydro's internal metering systems, Customer Information System, and Customer Care & Billing system ("CC&B").

In order for smart meter data to be retrieved by the provincial MDM/R from the utility's MDM systems, and to be transmitted back to the utility's billing system, it is necessary for Toronto Hydro's MDM and billing systems to be integrated with the provincial MDM/R system. The integration, or interfacing, must be implemented based on the protocols and specifications defined by the Smart Metering Entity ("SME"). Extensive testing is required when performing the integration to ensure the proper transmission of data between Toronto Hydro's systems and the provincial MDM/R.

E5.4.3.2 Failure Risk

Toronto Hydro was among one of the first utilities to implement Smart Meters in support of provincial policy objectives, installing the bulk of its residential and small commercial meters between 2006 and 2008. Given Toronto Hydro's status as an early adopter provincially and globally, there is an absence of empirical data from other utilities and jurisdictions of meter failure rates in relation to asset lifespan. However, in an Asset Depreciation Study undertaken by Kinetrics for the OEB (the "Kinetrics Report"), the expected lifespan of a typical smart meter was determined to be 5-15 years, which is consistent with Toronto Hydro's internal observed lifespans of other electronic based operational technology assets.[5] Beginning in 2021, Toronto Hydro's meters will surpass this 15 year lifespan, thereby increasing the probability of failure beyond standard operating levels.

As shown in Figure 1, above, the bulk of residential and small commercial & industrial meters will have their seals expire in 2024. At this time, the majority of meters will have been in service for 18 years. As the meter population ages, the probability of meter failures increases. By 2025, approximately 90 percent of Toronto Hydro's residential and small commercial meters will surpass their useful life. This will negatively affect Toronto Hydro's ability to accurately bill its customers (which is tied to the OEB's billing accuracy performance standards) as failed meters result in estimated billing.

[5] Kinetrics Inc., *Asset Depreciation Study for the Ontario Energy Board* (July 8, 2010), available at: < https://www.oeb.ca/oeb/_Documents/EB-2010-0178/Kinetrics-418033-OEB%20Asset%20Amortization-%20Final%20Rep.pdf>.

Higher failure rates pose a critical risk to Toronto Hydro's operations, affecting various elements of its business, including decreased billing accuracy, customer dissatisfaction (due to increased estimated bills and subsequent billing corrections), decreased financial stability (due to increased estimate based billing), increased costs to address meter failures on a reactive basis, and the potential failure to meet mandated OEB and other regulatory service standards (e.g. billing accuracy targets, restrictions on issuing multiple estimated bills, etc.).

To address this risk of failure, Toronto Hydro intends to replace its population of approximately 470,000 Elster REX 1 meters with next generation meters. This replacement will be staged over the 2022 and 2027 period. Meters will be replaced at or shortly following the end of their useful life of 15 years. The replacement schedule for any given meter will take place over the two years between their end of useful life and their seal expiry year.

The installation of next generation meters will also allow Toronto Hydro to expand the functionality of its metering population, through the installation of meters with remote disconnection capabilities. These meters will allow for quicker reconnection times for customers, and also result in less on-site field work, which will save labour and vehicle costs. This is beneficial to both the utility by reducing Toronto Hydro's operational expenditures and to the customer by reducing reconnection time.

In addition, the installation of these next generation meters will allow for "Last Gasp" functionality, which allows the meter to communicate an alert as it experiences an outage (see section below), to be rolled out across the distribution system beginning in 2022.

E5.4.3.3 Business Operations Efficiency

Metering technology supports the efficient and effective operation of Toronto Hydro's system. Given that the majority of Toronto Hydro's residential and small commercial smart meters were installed over 2006-2008, the rapid advancements in technology since that time have rendered the functionality of these first generation meters obsolete. While the replacements of these meters are primarily driven by failure risk, the advancements in technology have allowed for the adoption of new advanced functionalities during the replacement cycle. This new functionality will work to support efficient and effective grid management and customer service.

For example, the introduction of Last Gasp functionality is made available by the new models of the Elster meter. This facilitates customer level outage information and assists Toronto Hydro in reducing the duration of outages. This is accomplished by assisting with the localization of outages and therefore being able to more quickly direct crew deployments to affected areas. This technology also enables the implementation of customer specific reliability measures contemplated under Ontario's Long-Term Energy Plan.[6]

Following an alert facilitated by the Last Gasp functionality, the information in the Toronto Hydro metering system will be passed to the system for restoration efforts and crew dispatch. Last Gasp will help Toronto Hydro to locate the source of the outage in a more timely manner, which will help facilitate quicker outage response times by allowing crews to locate the source of the outage quicker, with a corresponding effect on system wide SAIDI. See Figure 6, below, for a depiction of the operation of the "Last Gasp" functionality.

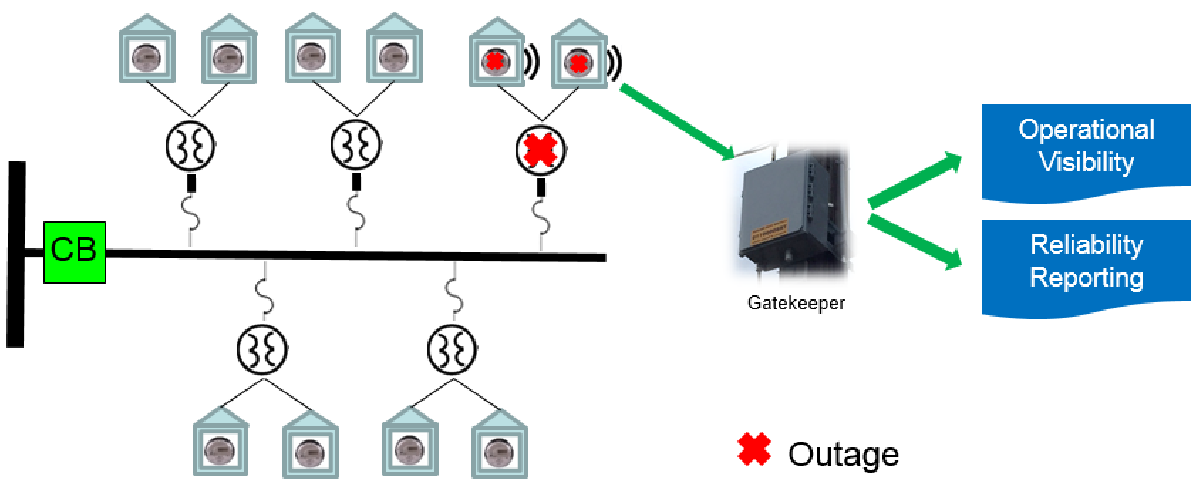


Figure 6: Last Gasp Function

The next generation meters also have a more effective transmitter that will drastically increase the range and penetration of the meter signal. This is expected to increase the number of meters successfully read, reducing "orphaned" meters and the number of manual reads required, and further reducing the number of estimated bills issued, increasing OEB billing accuracy metrics.

The introduction of meters with remote disconnection capabilities allows Toronto Hydro to reduce the cost of performing disconnections on its system, due to the reduced need for staff to physically

[6] Ontario's Long-Term Energy Plan 2017, Delivering Fairness and Choice (October 26, 2017), available at: < https://files.ontario.ca/books/ltep2017_0.pdf>.

attend a customer's property. This feature also enables customers to be reconnected faster after payment has been made, and allows for a more efficient and flexible implementation of OEB policy initiatives related to utility disconnection practices. Toronto Hydro already completes virtually all reconnections within 2 business days at least 90 percent of the time, as required by the OEB[7], but remote reconnection technology will allow for reconnection timelines significantly more convenient to customers.

1. Interval Metering System

Toronto Hydro intends to upgrade the Interval Metering system, ITRON Enterprise Edition ("IEE"), in order to continue to successfully meter Toronto Hydro's interval metered customers (those with greater than or equal to 50 kW demand). In 2011, Toronto Hydro had 3,300 Interval metered customers, and this increased to 7,000 in 2017. Toronto Hydro is projecting a further increase to 13,000 customers by 2020 due to the decommissioning of the 2G network in Toronto, and the consequent conversion by Toronto Hydro of its 2G meters to newer 4G technology. In order to keep up with this growth, the IEE system will need to be upgraded.

This upgrade will also lead to a reduction in the operational cost of the system in terms of licensing fees and IT support. The IEE system will have both data collection and exception management rolled into one system rather than two separate systems, and will also be able to communicate successfully with other meter types such as Suite Metered and Elster Interval meters. This will simplify the Interval data collection process, eliminating the need to collect interval data with multiple meter systems.

2. Residential Metering

Toronto Hydro must continually upgrade its residential metering system to ensure it continues to receive vendor support and is capable of enabling features available on newer generation meters. In 2021, Toronto Hydro plans to implement a new version of the residential metering system. This upgraded version will allow for the new "Synergy Mesh" – enabling enhanced communication features available in newer advanced meters - and implementing a Gatekeeper (Collector) replacement program. The new software will collect data from the residential meters every six hours versus the existing software which collects it once a day. This will allow customers to monitor their consumption with only a six hour delay. More importantly, the new generation of meters will reduce

[7] For a discussion of this OEB metric, please see Service Quality, found at Exhibit 2A, Tab 7, Schedule 1.

the number of manual meter reads and estimated bills. This will also allow Toronto Hydro to continue to ensure it is meeting its customer billing accuracy targets.

3. Suite Metering

Toronto Hydro intends to upgrade its Suite Meter Advanced Metering Infrastructure ("AMI") in order to maintain the meter reading and billing performance mandated by Measurement Canada and the IESO. The City of Toronto is experiencing significant condominium development. As a result of this customer growth, Toronto Hydro's current Suite Meter AMI system (Primeread) will no longer be able to retrieve and process the suite meter data fast enough on a daily basis to meet IESO's specifications, requiring Toronto Hydro to upgrade its data collection system. The lifecycle of the Suite Metering AMI has a scheduled upgrade roughly every three years to keep up with the influx of new suite metered customers. Primeread was initially brought online in 2012, the first upgrade took place in 2015 and the next scheduled upgrade is in 2018.

4. Operational Data Storage Upgrade ("ODS")

Presently, ODS is used solely for transferring consumption data from meters into Toronto Hydro's CC&B. The upgrade scheduled for 2022-2023 will enhance the ODS to better manage Toronto Hydro's billing data and enable energy monitoring and control capabilities for distributed generation energy resources across the Toronto Hydro distribution system. These capabilities will also allow for the management of generation, storage, and demand response assets while the Control Centre will continue to manage system configuration. The ODS will also be used to process smart meter data into the new Network Management System ("NMS"). This will enable a more streamlined and efficient approach to distributed generation projects and a more efficient approach to adding metering data into the NMS for outage management solutions.

5. Mobile Workforce Management

Over 2018 and 2019, Toronto Hydro plans to implement a Mobile Workforce Management system. This system is presently configured to only work with Toronto Hydro's residential meters. The system benefits Toronto Hydro customers as it ensures accurate and timely metering replacements.

When an existing meter in the field is replaced a technician must take an "off read" prior to installing the new meter. This ensures that all of the consumption data registered by the old meter is recorded and billed to the customer. With Toronto Hydro's previous system, this was accomplished with paper record keeping. The new Mobile Workforce Management software ensures that all meter changes and field activities are processed electronically with the serial number of the old and new meter verified and recoded via a barcode, as opposed to the previous method of recording the serial numbers manually. This new electronic method reduces the risk of billing errors and will allow for the meter "off reads" to be sent directly from the field for billing.

By 2022, Toronto Hydro plans to undertake upgrades to the Mobile Workforce Management System that will ensure continued functionality of the system as the number of meter change and installation requests increases, and will allow it to be used across all of the various meter types in Toronto Hydro's system. This will greatly improve the efficiency of meter changes.

E5.4.4 Expenditure Plan

Toronto Hydro's historic and forecast spending in the Program is shown in Table 4, below. Expenditures in the Program are largely driven by the timing of metering and metering system upgrade cycles.

Table 4: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Metering	14.5	17.4	24.8	23.1	26.1	22.6	14.8	23.6	30.6	39.2

Table 5, below, shows a detailed breakdown of 2015-2019 spending within the Program.

Spending remained generally stable over 2015-2016, with a step increase between 2016 and 2017. This increase was primarily driven by the requirements to undertake a 2G meter replacement. As the 2G network band in Canada is in the process of being shut down, Toronto Hydro must replace all of its existing 2G smart meters with 4G models, and expects to complete this process during the 2017 to 2019 period. The spending over 2017-2019 also reflects increased spending related to the targeted installation of remote disconnect meters in specific locations. These meters allow Toronto Hydro to disconnect service without requiring on-site attendance by a crew, reducing operational costs for the utility, and improving service by reducing reconnection time for affected customers.

As can be seen in Table 5, over 2018-2019, spending decreases on System Upgrades and Large Customer and Interval Metering are offset by cost increases in other areas of the Program, such as the Residential and Small C&I Meter Replacement and Wholesale Metering.

Table 5: Actual & Bridge Program Costs 2015-2019 ($ Millions)

	2015	2016	2017	2018	2019	Total
Residential and Small C&I Meter Replacement	4.4	5.3	4.3	3.7	10.1	**27.8**
Suite Metering	5.9	6.1	5.3	5.2	5.3	**27.8**
Large Customer and Interval Metering	0.0	0.0	6.4	4.3	0.6	**11.3**
Wholesale Metering	2.6	1.7	4.6	3.3	6.5	**18.7**
System Upgrades	1.7	4.3	4.3	6.7	3.7	**20.7**
Total	**14.5**	**17.4**	**24.8**	**23.1**	**26.1**	**106.3**

Table 6, below, provides a breakdown of Toronto Hydro's forecast expenditures over the 2020-2024 plan period. This forecast is based on the number of meters that will need to be resealed or replaced in each year. Costs for metering system upgrade initiatives are based on a paced installation schedule using currently available cost estimates.

As shown below, Toronto Hydro's forecast spending in most categories over the 2020-2024 plan period is generally stable and in-line with its historical spending over the 2017-2019 period. The sole exception is the residential and small commercial meter replacement initiative, which reflects Toronto Hydro's intention to replace these meters over a six year period beginning in 2022, corresponding to the period during which these meters will both age beyond their expected useful life and have their seals expire (refer to Options Analysis section for additional details).

Table 6: Forecast Program Costs 2020-2024 ($ Millions)

	2020	2021	2022	2023	2024	2020-2020 Total
Residential and Small C&I Meter Replacement	7.1	4.2	15.6	24.5	31.9	**83.3**
Suite Metering	4.7	5.2	4.7	4.4	4.4	**23.5**
Large Customer and Interval Metering	0.7	0.0	0.0	0.1	0.4	**1.3**
Wholesale Metering	7.3	1.6	0.0	0.0	0.0	**9.1**
System Upgrades	2.8	3.8	3.2	1.5	2.4	**13.7**
Total	**22.6**	**14.8**	**23.6**	**30.6**	**39.2**	**130.8**

Toronto Hydro prioritizes the replacement of meters based on their seal expiry dates. Those meters with earlier seal expiry dates will be prioritized for replacement. The meters with expiring seals typically also reflect the oldest meters in the meter population.

E5.4.5 Options Analysis

E5.4.5.1 Options for Revenue Meter Compliance

The Revenue Meter Compliance segment includes many tasks that must be completed in order to remain in compliance with Measurement Canada Regulations. This includes the Revenue Meter Replacement program for Suite Meters, Interval Meters, and Large Users and the Metering System Upgrades for Residential, Suite Meters, and Interval Meters. These projects must be completed to ensure continued compliance with Measurement Canada and OEB regulations. For example, for the interval and suite metering projects, Toronto Hydro must maintain the meter seals to ensure continued compliance with requirements contained in the *Weights and Measures Act* and the *Electricity and Gas Inspections Act*.

The major project for the Revenue Meter Compliance segment over the 2020-2024 plan period is the residential and small commercial meter replacement. This project has four options for completion, which are discussed in detail below.

Adjusted cost calculations were derived based on the total cost of each option. The calculation for the seal extension option was derived with the total cost of the program out to 2033, when the last of the meters would be replaced.

1. **Option 1: Seal Extensions for Residential and Small Commercial and Industrial Meters**

This option would require Toronto Hydro to sample the residential and small C&I (Commercial and Industrial) meters that will expire over the 2024-2026 period and extend the seals of the meters for another 6 years. This involves forming sample groups, randomly selecting approximately 3 percent of the meters in each sample group, taking them out of service, and testing them for accuracy. If the old meters pass the test, then all meters in the sample group will have their seals extended by 6 years. The meters would then be replaced upon expiry of the re-seal, beginning in 2030.

The main benefit of this option is that it is the least capital intensive of the three, as it defers the meter investment into a future period. However, this option carries with it some considerable risk. First, it is based on an optimistic assumption that all meter batches will pass the resealing test (and will not require immediate replacement). There is also a considerable risk that even after being resealed, the meters may deteriorate or fail in the field. Most meters would be 20-25 years old by the time of the next reseal cycle, nearly 10 years beyond their expected maximum useful life of 15 years. Substantial meter failures would have a significant impact on Toronto Hydro's operations, affecting billing accuracy, customer satisfaction, compliance, and financial stability. Such meter failures would also negatively affect Toronto Hydro's operational costs by requiring more costly reactive spot replacements.

In addition, by continuing to rely on the first generation meters, Toronto Hydro would not be able to take advantage of additional benefits offered by newer generation meters, including remote disconnect capabilities and Last Gasp functionality that would enable quicker restoration times during outages. The latter is also an enabling component of Customer Specific Reliability Measures, which the OEB has been exploring on a pilot basis, and which forms part of the Long Term Energy Plan 2017.

The total adjusted cost of this option from 2021-2033 is $90.8 million.

2. Option 2 (Selected Option): Replace Meters over a Six Year Period (2022-2027)

In this option, Toronto Hydro would replace the entire population of Elster REX 1 meters with next generation meters, the replacement would be staged over a five-year period between 2022 and 2026. Meters would start being replaced as soon as or shortly after they hit the end of their useful life of 15 years, and the replacement schedule for any given meter would generally take place over the two years between their end of useful life and their seal expiry year.

This pacing option achieves the objectives of the required replacement by addressing the pending seal expiry issue, adequately addressing the potential failure risk driven by end of life meters, allows for remote disconnect and Last Gasp functionality to be rolled out across the system beginning in 2022, and largely avoids a "lumpy" investment cycle. This option also reduces the financial impacts of the replacement for current ratepayers by delaying and condensing the investment to the maximum extent possible. Given these considerations, Toronto Hydro has selected Option 2 as its approach.

The total adjusted cost of this option from 2021-2033 is $115.1 million.[8]

[8] The adjusted cost only covers the Residential and Small Commercial portion of the budget.

3. Option 3: Replace Meters over a Four Year Period (2024-2027)

This option would require the replacement of the entire population of roughly 470,000 Elster REX 1 meters with next generation meters when the majority of seals expire in the 2024-2026 period. The meters would generally be replaced in the year of their seal expiry.

This option would address the seal expiry issue, and reasonably address the potential failure risk driven by end of life meters, however this option would require the meters to operate roughly three years beyond their expected useful life. It would also allow remote disconnect and Last Gasp functionality to be rolled out across the system beginning in 2024.

Overall, this option requires a considerable capital replacement of meters over a relatively short 3 year period. This would result in a resource intensive replacement program and a "lumpy" investment cycle that negatively affects both rates and future subsequent replacement and maintenance scheduling.

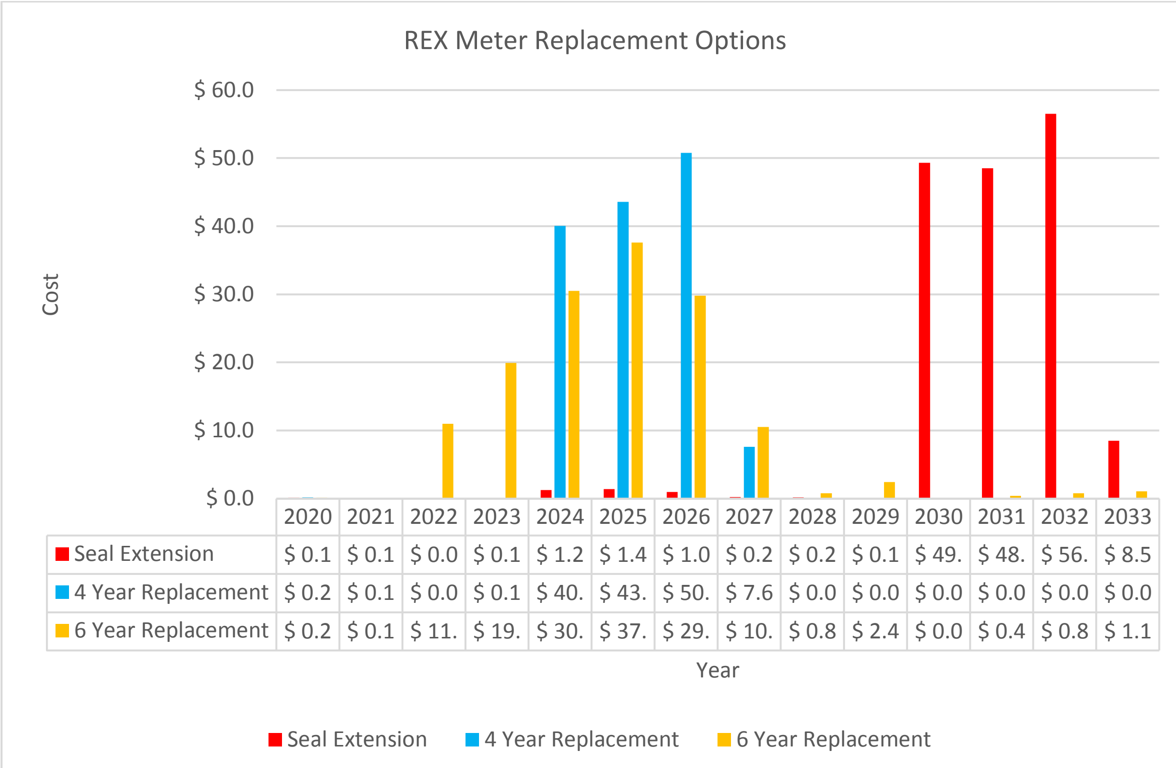
The total adjusted cost of this option from 2021-2033 is $110.2 million.[9]

4. Options Comparison

The Figures below compare the three options, in terms of spending:

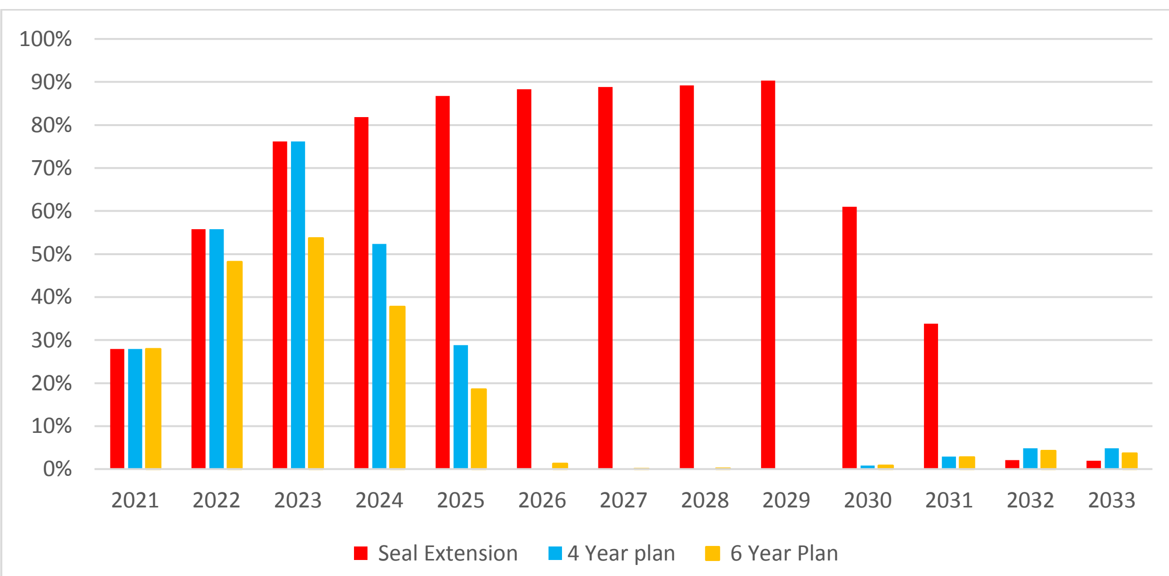
- **Figure 7**: Meter Replacement Options – Spending Profile Comparison, meters past the end of their useful life;
- **Figure 8:** Meter Replacement Options - Meters Past Useful Life; and
- **Figure 9**: Meter Replacement Options – Meter Replacements per Year.

[9] The adjusted cost only covers the Residential and Small Commercial portion of the budget.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Seal Extension	$ 0.1	$ 0.1	$ 0.0	$ 0.1	$ 1.2	$ 1.4	$ 1.0	$ 0.2	$ 0.2	$ 0.1	$ 49.	$ 48.	$ 56.	$ 8.5
4 Year Replacement	$ 0.2	$ 0.1	$ 0.0	$ 0.1	$ 40.	$ 43.	$ 50.	$ 7.6	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
6 Year Replacement	$ 0.2	$ 0.1	$ 11.	$ 19.	$ 30.	$ 37.	$ 29.	$ 10.	$ 0.8	$ 2.4	$ 0.0	$ 0.4	$ 0.8	$ 1.1

1 **Figure 7: Meter Replacement Options – Spending Profile Comparison**



2 **Figure 8: Meter Replacement Options – Meters past Useful Life**

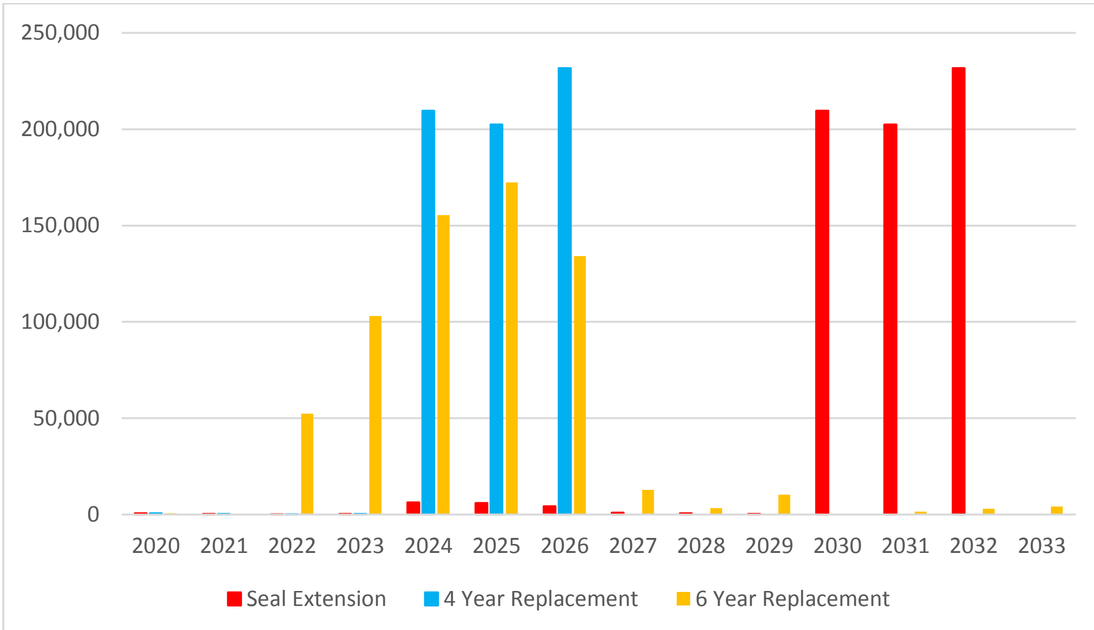


Figure 9: Meter Replacement Options – Meter Replacements per Year

E5.4.5.2 Options for Wholesale Metering Compliance

For the Wholesale Metering Compliance segment, no other options are available to Toronto as the utility is required to complete the remaining Meter Service Provider ("MSP") conversions, in accordance with IESO's mandated requirements.

E5.4.6 Execution Risks & Mitigation

The table below illustrates the major program risks that may occur while executing the Program.

1 **Table 7: Meter Risks, Impact, Probability, and Mitigation**

Project Segment	Risk	Impact	Risk Probability	Mitigation
Revenue Meter Compliance	Large Batches of required meters may not be received in time for installation or replacement	The program would have to be modified and timelines potentially stretched. This would potentially force Toronto Hydro to reseal meters past useful life, increasing capital expenditures and risk of failure	Low – Provided enough lead time meters should arrive when required.	Ensure that enough lead time is provided to the vendor to ensure delivery of equipment as required.
Wholesale Metering	Hydro One projects enabling Toronto Hydro's required meter replacements are delayed.	Compliance with IESO Market Rules is affected or delayed.	Medium – projects are complicated and subject to equipment delays and resource availability.	Work closely with Hydro One to schedule work and to allocate appropriate resources to metering compliance projects.

E5.5 Generation Protection, Monitoring, and Control

E5.5.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 13.6	**2020-2024 Cost ($M):** 13.6
Segments: Generation Protection, Monitoring, and Control	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Service, Safety, Reliability, Public Policy	

The Generation Protection, Monitoring, and Control program (the "Program") allows Toronto Hydro to fulfill its regulatory obligations under section 6.2.4 of the Distribution System Code ("DSC") and section 25.36 of the *Electricity Act* to connect distributed generation ("DG") projects to its distribution system; including renewable energy generation ("REG") projects such as solar photovoltaic, wind and bio-gas. It also allows Toronto Hydro to meets its obligations under section 6.1 of its Distribution License and section 26 of the *Electricity Act* to provide generators with non-discriminatory access to its distribution system. Toronto Hydro's investments in this Program consist largely of "renewable-enabling improvements", as defined in sections 1.2 and 3.3.2 of the DSC.

As of the end of 2017, Toronto Hydro has connected over 1,780 DGs totalling 226 MW in capacity. The utility is forecasting a continued increase in DG connections (including energy storage), reaching an estimated 800 MW by the end of 2024. To alleviate existing connection capacity constraints that may prevent the expansion of DG in a number of areas, and to provide Toronto Hydro system controllers with the necessary capabilities to monitor and control DG connections, Toronto Hydro plans to continue making investments in two types of work over the 2020-2024 period:

- generation protection measures, through the installation of bus-tie reactors at five station buses to alleviate short circuit capacity constraints; and
- the installation of 414 monitoring and control systems ("MCS") for REG facilities to provide situational awareness and control of DG facilities on the distribution system.

1 ## E5.5.2 Outcomes and Measures

2 **Table 2: Outcomes & Measures Summary**

Customer Service	• Contributes to Customer Service objectives by: ○ Enabling the connection of new generation customers without extensive delays or adverse impacts to existing and new customers (as per section 6.2.4 of the DSC 90 percent of the time on a yearly basis within 5 business days as per the DSC section 6.2.7 and 6.2.7A); ○ Complying with sections 25.36, 25.37 and section 26 of the Electricity Act, 1998 by connecting DG customers to its distribution system; ○ Providing system Toronto Hydro with a level of precision in DG capacity monitoring to enable the maximum allowable amount of generation to be connected to the grid.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Ensuring the operation of the distribution system remains within allowable designed short circuit current limits by installing 5 bus-tie reactors on station buses; ○ Avoiding unintentional islanding and reducing the islanding risk of DG sources; and ○ Ensuring bi-directional flows remain within distribution system design parameters including thermal and short-circuit capability by installing MCSs at existing and new DG facilities.

Safety	• Contributes to maintaining Toronto Hydro’s Total Recorded Injury Frequency (TRIF) measure and employee safety by: ○ Preventing backfeed situations by automatically issuing an electronic trip/shutdown command to isolate DG when feeder breakers are opened (as per the Electrical Utility Safety Association (“EUSA”) Rule 149 – Backfeed); ○ Adhering to Ontario Electricity Safety Code (“OESC”) Rule 84-008, which requires distributed generation systems to automatically disconnect electric power from the distribution system; and ○ Providing power system controllers tools to remotely disconnect DG as part of the Work Protection Code procedures to safeguard linepersons from unexpected generator start-up, preventing backfeed into the local distribution grid area while field crews are present.
Public Policy	• Contributes to Toronto Hydro’s public policy objectives by: ○ Enabling the connection of distributed generation facilities to the system in support of public policy objectives contained within the Green Energy and Green Economy Act (“GEGEA”) and the Long Term Energy Plan (“LTEP”);

E5.5.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Reliability, Customer Service Requests

The Program is instrumental to Toronto Hydro’s efforts to enable DG connections to its distribution system. This Program is fundamentally customer-driven, as the proposed work will allow Toronto Hydro to connect additional customer DG projects to the distribution system through the Customer and Generation Connections program. Additionally, distribution systems, including monitoring and protection systems, were planned, designed and built to serve loads but were not intended to facilitate the connection and management of a large number of distributed generators. As a result, there is a need to address the system constraints to enable generation connections to the distribution system.

The Program is required to enable system access for the existing and forecasted levels of DG on Toronto Hydro’s distribution system (as some existing solar DG connected to the grid does not have and will require MCS). As per Section 6.2.4 of the DSC, and sections 25.36 and 25.37 of the Electricity Act, Toronto Hydro is mandated to connect DG customers to its distribution system. Toronto Hydro is also obligated under section 6.1 of its Distribution License and section 26 of the Electricity Act to provide generators with non-discriminatory access to its distribution system and to provide priority access for renewable energy generation facilities.

The planned investments are critical renewable enabling improvements that Toronto Hydro must carry-out in order to safely and reliably facilitate the continuing proliferation of REG facilities across the City of Toronto. By addressing short-circuit limitations on the system and installing required monitoring and control capabilities, Toronto Hydro will be able to continue to deliver an efficient and timely DG connections program (detailed in section 3.2.1).[1]

Figure 1 below illustrate typical DG installations on the Toronto Hydro distribution system, as enabled by investments in this Program.

Figure 1: Residential (left) and Residential (right) DG Installation

E5.5.3.1 Proliferation of Distributed Generation Facilities

As of the end of 2017, Toronto Hydro has responded to over 8,000 inquiries from customers and developers seeking to connect generation under various programs, including the Independent

[1] As per section 6.2.7 and 6.2.7A of the DSC, Toronto Hydro is required to connect new micro-embedded generation facilities on time, 90 percent of the time on a yearly basis within 5 business days.

Electricity System Operator ("IESO") programs,[2] Net-Metering, Energy Storage, Combined Heat and Power ("CHP"), Closed Transition and Load Displacement. A wide range of proponents have submitted project applications, including many schools, housing managers, large grocery stores, condominium corporations, and department stores. As of the end of 2017, Toronto Hydro has connected over 1,780 DGs of various sizes. Details on the number of projects and total kilowatts of DGs connected by size and technology can be found in the Customer Connections program.[3]

Interest in generation projects within Toronto Hydro's service territory has been steadily increasing and this trend is anticipated to continue into the future. There has been a growing interest in the Net Metering program and battery energy storage as costs associated with solar photovoltaic panels, inverters, and lithium-ion batteries continue to fall. Inquiries for medium and large sized CHP installations have more than tripled since 2015, largely due to larger industrial and commercial customers seeking site reliability. Toronto Hydro has also observed increased interest in small scale micro turbine-based installations. Toronto Hydro anticipates a large volume of applications for the connection of micro turbine-based CHP facilities, which are well-suited to generation in commercial and multi-level residential buildings.

DG projects are expected to more than double by 2024, reaching approximately 3,600 connections. This represents an additional 581 MW on top of the 226 MW of existing DG as of the end of 2017, as seen in Figure 2. Toronto Hydro's DG connection forecast is based on historical DG connections, initial consultations and preliminary assessments received and completed from 2009 onwards. These include initial consultations regarding Net-Metering, CHP, Closed Transition, Load-Displacement, and IESO programs such as PSUI, FIT and Energy Storage Procurement. The forecast takes into account the historical connection trends, completed assessments, and anticipated projects with respect to various DG programs. For more information on generation connections see the Customer Connections program.[4]

[2] Feed-in-Tariff (both micro-FIT ≤10 kW and FIT >10 kW), Process and Systems Upgrade Initiative ("PSUI"), Renewable Energy Standard Offer Program ("RESOP")
[3] See Exhibit 2B, Schedule E5.1
[4] *Supra* note 3.

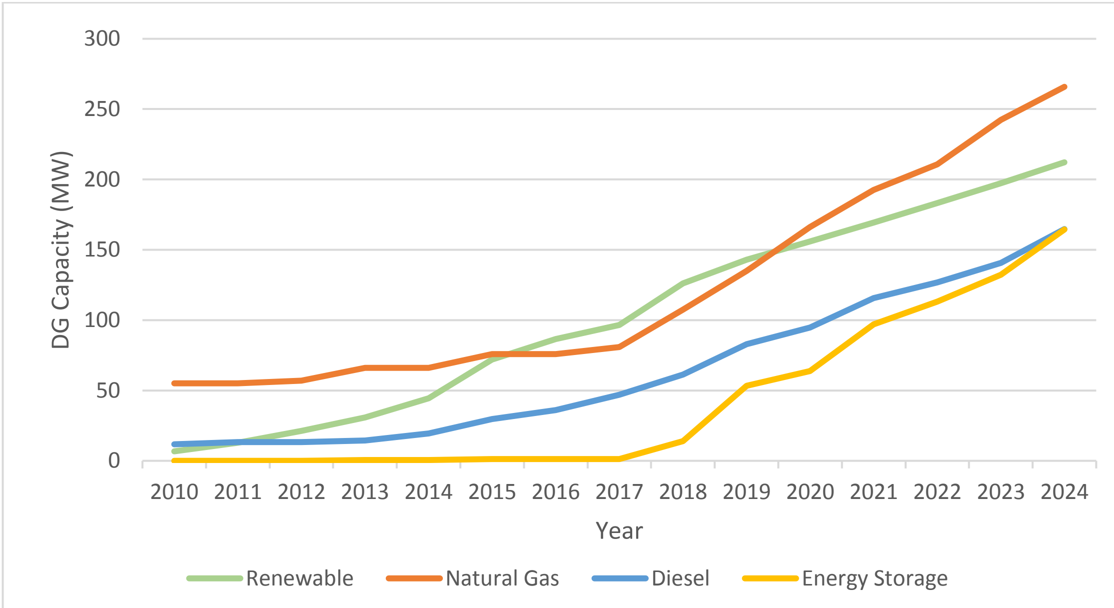


Figure 2: Historic and Forecasted Generation Capacity 2010-2024

Currently, the ability to connect new DG is limited by constraints on Toronto Hydro's system. As DG connection requests increase, it is necessary to address these constraints to accommodate the anticipated connection requests to be made in a timely manner and to meet the requirements set in section 6.2.7 of the DSC. Toronto Hydro faces short circuit, reverse power flow and anti-islanding issues that can inhibit the ability to connect the forecasted DG projects. Over time, larger concentrations of micro-generators, or several medium-sized generators on the same distribution feeder can have a noticeable impact on the short circuit and loading levels on the distribution system and upstream elements. Investments are therefore necessary to overcome short-circuit capacity constraints and to facilitate integration of DG into the distribution grid with bi-directional flow capability. Without these investments, Toronto Hydro may not be able to meet its regulatory obligations and respond to the public policy objectives of the Province with respect to the expansion of renewable energy generation sources.

E5.5.3.2 System Capability to Connect Distributed Generation

Toronto Hydro supports connecting DG to the distribution system in alignment with the DSC and in coordination with Hydro One and the IESO. Toronto Hydro has identified a number of constraints within its system that impact DG connections and interconnection-related decisions. The issues that limit Toronto Hydro's ability to connect DG include short-circuit capacity, risk of islanding, thermal limits, and the lack of ability to transfer loads between feeders during planned work and emergency situations.

Asset failure can occur when distribution equipment exceeds system short circuit levels, equipment thermal ratings and nominal voltage ratings. Failures due to distribution system stresses from DG sources can cause transformer equipment failure, surge arrester failure, nuisance outages from sympathetic[5] tripping and other similar effects.

The capacity and type of generation connected to both feeders and stations must be managed to ensure reliable operation, and prevent damage to existing transformers, circuit breakers and fuses. Introducing increased levels of bi-directional flows from DG will require protection, monitoring, and control to prevent such occurrences during normal operation, planned work and emergency situations.

1. Short Circuit Capacity Limitations

Short circuit limits on both the Toronto Hydro and Hydro One systems are important factors in determining how much DG can be connected to Toronto Hydro's distribution system. Prior capacity studies (Navigant DG Report, April 2011) confirm short circuit limits on station equipment to be one of the primary limiting factors on the amount of DG that can be installed in certain areas of the Toronto Hydro system.

Recent applications for FIT connections and the Navigant report demonstrate the potential for DG and underscore the impact of short circuit capacity on allowable DG penetration. The primary limiting element for short circuit capacity is substation equipment (where fault current levels are highest) and, more specifically, substation load side breakers. Annual fault studies conducted by Toronto Hydro confirm that stations serving 27.6 kV primary distribution have significantly greater spare short circuit capacity than downtown stations serving 13.8 kV distribution.

2. Bus-Tie Reactors

To facilitate DG connections, bus-tie reactors can be installed on the bus to mitigate high fault current levels. They lower the short circuit current on the station bus and distribution system by inserting impedance at the bus-tie point. This limits the fault contribution of the two transformer windings in

[5] Sympathetic tripping is the phenomenon on feeders when a protective device (that should not operate) operates in response to fault or condition on a downstream part of the feeder that is protected by another protective device.

a typical Dual Element Spot Network ("DESN") type station arrangement. A reactor of 0.5 ohms installed at a bus-tie could allow up to an additional 15 MW of DG capacity. Since they are essentially a linear inductive reactance, their cumulative impedance will add to the system's impedance which will result in a reduction of the fault currents. The main advantage of series reactors is that they allow the use of existing equipment without costly modifications or replacements.

To facilitate Toronto Hydro DG customer connections, coordination with Hydro One is required to install these bus-tie systems. Toronto Hydro plans to work with Hydro One to install bus-tie reactors at stations where fault current constraints become an issue.

Toronto Hydro anticipates that five bus-tie reactors will be required over the 2020 to 2024 period to alleviate short circuit capacity constraints. The station buses where bus tie reactors are proposed are shown in Table 4 below.

Table 4: Bus Tie Reactor Installations

		Forecasted DG Connections by 2019		Forecasted DG Connections by 2024 (without bus-tie reactor)	
Station Name	Bus	Total Capacity (MW)	Available Short Circuit Capacity (MVA)	Total Capacity (MW)	Available Short Circuit Capacity (MVA)
Ellesmere TS	J	7.9	49.6	12.5	-0.5
Esplanade TS	A1A2	7.3	57.6	17.9	-29.6
Fairbank TS	YZ	2.7	6.0	7.9	-10.6
Horner TS	BY	14.6	92.8	20.8	-4.6
Sheppard TS	BY	3.5	21.7	9.4	-4.0

E5.5.3.3 System Monitoring to Control Distributed Generation

As mentioned, lack of monitoring of and control over the distributed generation on the grid can lead to increased risks of islanding, overloading the system, and increased thermal ratings. These can be addressed through the installation of MCSs.

1. Anti-Islanding Condition for Distributed Generators

Islanding occurs when a DG source continues to power a portion of the grid even after the main utility supply source has been disconnected or is no longer available. This situation must be avoided as it can interfere with grid protection systems. It can also create dangerous backfeeds on the distribution system exposing workers to live circuits they believed to be de-energized.

Monitoring and control can mitigate the risks associated with DG for the public and Toronto Hydro field personnel. DG systems are required by Rule 84-008 of the *Ontario Electricity Safety Code* ("OESC") to have backfeed protection so that in the absence of electrical power (potential) on the utility's supply, generators cannot energize the utility's supply. Protection circuits can and do fail which can energize supply lines creating contact hazards for utility workers, contractors and the others who may be working on circuits expected to be de-energized. As per EUSA Rule 149, backfeed hazards must be identified and eliminated where possible, or controlled using approved temporary grounding procedures. Due to the hazard of backfeed, work is not to be performed on transformers connected in parallel or banked (except for replacing fuses using live line tools) until all sources of electrical energy have been removed from both the secondary and primary sides of the transformer to be worked on. The Electrical Safety Authority ("ESA") Bulletin DSB-07/11, dated August 17th, 2011, outlines an example where an inverter failed to disconnect and started to back feed into the local distribution system.

> *"The Ontario Electrical Safety Code (OESC) rule 84-008 requires a distributed generation system to automatically disconnect electric power production sources when there is a loss of power from the supply authority. In the case of this near miss incident, the solar inverter's "anti-islanding" feature failed to fully disconnect the energy produced from the PV system."*

If the anti-islanding feature of a DG were to fail, as it did in this situation, the DG would backfeed into the local distribution system. The possibility of electric shock due to this scenario would pose a safety risk to the public, Toronto Hydro field personnel and the system in general. Active monitoring and control systems help avoid this situation by automatically issuing an electronic trip or shutdown command when the feeder breaker is opened.

The connection of photovoltaic solar inverters and other DG sources must be accomplished in a manner that ensures that unintentional islanding of DG sources cannot occur. Toronto Hydro plans to deploy real-time monitoring and control investments proposed within this Program at new DG sites greater or equal to 50 kW as per section 3.3.3 of the DSC to provide the needed ability to address anti-islanding concerns.

One of the anti-islanding measures in the IEEE 1547 Standard for Interconnecting Distributed Resources (DR) with Electric Power Systems, section 4.4.1, recommends that a distributor ensure that "*DR aggregate capacity [be] less than one-third of the minimum load of the Local Electric Power System (EPS).*" As the ratio of generation capacity to minimum load increases, the amount of time required by inverters to respond to anti-islanding scenarios also increases and the likelihood of inverters responding to anti-islanding scenarios decreases.

With the proliferation of DG in Toronto in recent years, several feeder circuits have already surpassed the generation to minimum load ratio of one-third. A total of thirteen distribution feeders have ratios ranging from 0.34 to 0.5 (refer to Table 5 below). These feeders currently present an increased risk of unintentional islanding conditions to the distribution system.

Table 5: Existing Feeders with Generation to Load Ratio Greater Than One-Third

Feeder Name	TS Station Name	TS Bus	DG Connected (MW) in 2017	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
47-M1	***Sheppard***	*B*	1.8	3.5	0.50
63-M6	***Agincourt***	*Y*	2.9	6.9	0.43
55-M31	***Finch***	*J*	1.3	3.0	0.42
A-35-T	***Strachan***	*A7A8*	1.0	2.4	0.42
A-31-W	***Wiltshire***	*A5A6*	0.3	0.6	0.41
80-M10	***Fairchild***	*Y*	1.4	3.8	0.35
R29-M5	***Rexdale***	*B*	0.5	1.4	0.35
38-M4	***Manby***	*F*	0.6	1.6	0.35
53-M3	***Bermondsey***	*B*	0.6	1.8	0.35
R43-M31	***Warden***	*J*	0.7	2.0	0.34
88-M13	***Richview***	*E*	0.8	2.5	0.34
55-M1	***Finch***	*B*	2.0	6.0	0.34
R30-M3	***Horner***	*B*	0.8	2.4	0.34

DG penetration is growing rapidly as an additional forty five feeders are approaching the one-third limit (as shown in Table 6). These numbers take into account the forecasted 581 MW of additional DG capacity anticipated by the year 2024. This increase in DG penetration will further exacerbate the existing islanding risks and adversely affect Toronto Hydro's ability to safely and reliably connect additional DG to the distribution system. Monitoring and Control Systems allow Toronto Hydro to prevent concerns of anti-islanding as these give the utility the ability to remotely turn off the DG if they unintentionally island. If not addressed by proactive investments in control and monitoring capabilities, the generation to minimum load ratios could ultimately limit the number of DGs Toronto Hydro is able to connect to the system. These systems also provide greater visibility into the grid and allow the utility to enable more DGs to connect, as explained in section E5.5.3.3.

Table 6: Feeders Forecasted to Exceed Generation to Load Ratio Requirement in 2024

Feeder Name	TS Station Name	TS Bus	DG Connected (MW) in 2024	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
A-21-CE	***Cecil***	*A1A2*	21.0	3.6	4.19
38-M9	***Manby***	*B*	1.1	0.7	1.49
11-M3	***Runnymede***	*B*	10.6	7.7	1.38
A-16-K	***Gerrard***	*A1A2*	4.3	3.2	1.34
H9-M29	***Ellesmere***	*J*	6.6	5.0	1.31
A-12-BN	***Basin***	*A5A6*	4.0	3.1	1.30
35-M8	***Fairbank***	*Z*	4.1	3.3	1.27
34-M6	***Leaside***	*Y*	23.3	7.2	1.15
A-26-WR	***John***	*A11A12*	3.0	3.0	1.00
502-M32	***Cavanagh***	*Q*	1.4	1.6	0.91
R43-M25	***Warden***	*J*	2.2	2.4	0.90
47-M18	***Sheppard***	*Q*	1.0	1.2	0.84
E5-M24	***Scarborough***	*Q*	4.0	5.0	0.80
53-M12	***Bermondsey***	*Y*	1.9	2.4	0.78
R26-M33	***Malvern***	*J*	5.2	67	0.77
A-12-CE	***Cecil***	*A7A8*	2.1	2.9	0.74
35-M1	***Fairbank***	*B*	1.4	1.9	0.71
11-M1	***Runnymede***	*Y*	1.5	2.1	0.71
R29-M34	***Rexdale***	*Q*	1.4	1.9	0.71
55-M10	***Finch***	*Y*	1.5	2.2	0.71
53-M8	***Bermondsey***	*Y*	3.0	4.5	0.66
85-M30	***Bathurst***	*J*	5.8	1.6	0.63
R26-M31	***Malvern***	*J*	2.1	3.4	0.62
A-65-A	***Terauley***	*A3A4*	1.2	2.0	0.60
E5-M10	***Scarborough***	*Y*	1.9	3.2	0.60
R29-M6	***Rexdale***	*Y*	1.8	3.2	0.58
85-M24	***Bathurst***	*J*	2.2	3.8	0.57
R43-M24	***Warden***	*Q*	1.5	2.7	0.56
R29-M33	***Rexdale***	*J*	1.5	2.6	0.56
35-M23	***Fairbank***	*B*	1.1	2.0	0.55
85-M6	***Bathurst***	*B*	5.9	3.9	0.55

Feeder Name	TS Station Name	TS Bus	DG Connected (MW) in 2024	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
R29-M3	***Rexdale***	*B*	1.8	3.4	0.54
R26-M32	***Malvern***	*Q*	1.6	3.0	0.54
H9-M32	***Ellesmere***	*Q*	2.8	5.3	0.53
85-M4	***Bathurst***	*B*	1.9	3.6	0.52
47-M15	***Sheppard***	*J*	2.9	5.6	0.52
80-M27	***Fairchild***	*J*	1.0	2.0	0.51
63-M5	***Agincourt***	*B*	2.7	5.3	0.51
R43-M29	***Warden***	*J*	2.5	4.9	0.50
80-M2	***Fairchild***	*Y*	1.6	3.3	0.48
R29-M36	***Rexdale***	*Q*	1.8	3.8	0.47
47-M3	***Sheppard***	*B*	2.2	4.8	0.46
51-M32	***Leslie***	*Q*	1.1	2.4	0.46
11-M5	***Runnymede***	*B*	1.0	2.6	0.39
51-M25	***Leslie***	*J*	2.2	2.6	0.38

2. System Thermal Limits and Load Transfer Capability

Protection, monitoring and control upgrades also provide the ability to connect additional DG by ensuring system loading thresholds are satisfied. Exceeding system loading limits, as seen in Table 5 and Table 6, sacrifices the life of distribution equipment and can cause immediate equipment failure as mentioned earlier.

For large sized generation connections or the aggregation of small and medium sized generation connections, limiting a feeder’s continuous load thermal ratings is an important operating condition. Feeder planning and operation account for the system impact when the generator is up and running as well as when the units go off-line. These thermal levels come into play with factors such as the variability of various generation sources, system load growth and the occurrence of contingencies.

The ability to provide monitoring and control allows Toronto Hydro to monitor and mitigate the impact of thermal loading. This enables the utility to have more visibility into actual impact and variability of DG on the system and will therefore enable Toronto Hydro to be better equipped to make more accurate planning and operations decisions regarding thermal levels.

a. Monitoring and Control Systems

Since the 2015-2019 CIR, Toronto Hydro has been installing monitoring and control systems for all new DG connections. This has provided the visibility required to monitor the ratios in real time to ensure all DG sites are de-energized in the event of a system fault. With the continued implementation of the Program, Toronto Hydro will be able to actively monitor and control DG's in real time to ensure these ratios are within tolerable levels and the anti-islanding feature of the DG's have properly operated in the event of a distribution system fault.

Due to the volumes of forecasted DG connections from 2020 through to 2024, Toronto Hydro requires real-time monitoring and control via utility communication networks and the supervisory control and data acquisition ("SCADA") system in order to ensure distribution system safety and the adequate management of bi-directional distribution grid flows from DG connections (Figure 3). Real-time monitoring and control is required for existing and future DG sites of 50 kW and above. Toronto Hydro is mandated to connect DG sites to the distribution system, as per Section 6.2.4 of the DSC.

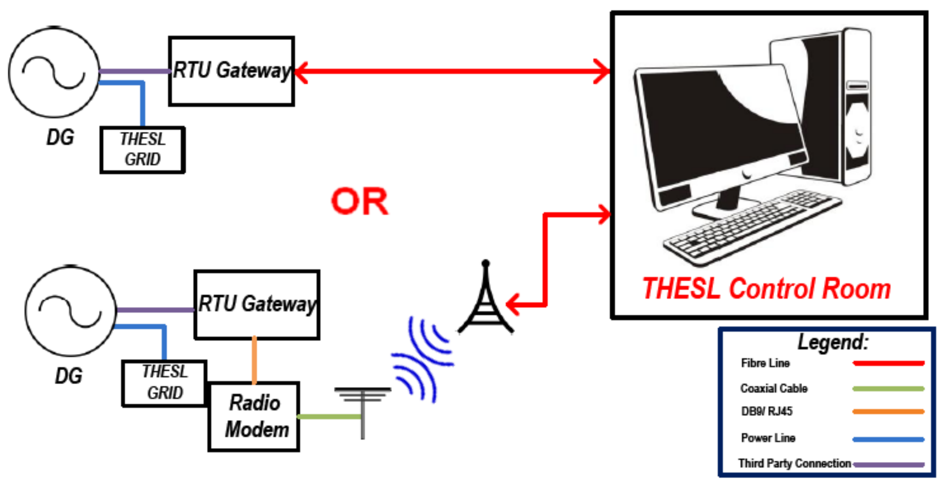


Figure 3: Monitoring and Control Interface to Toronto Hydro SCADA System

Monitoring and control provide situational awareness into the operating conditions of all DG connected to the distribution system, which will give Toronto Hydro the ability to collect data for planning purposes and to connect additional DG sites to the distribution system. This will have additional long-term value with respect to planning for future DG connections. Currently, Toronto Hydro assesses the potential to connect a DG site to the distribution system based on estimated thermal loading values. This approach assumes that a DG site will continuously generate 100 percent of its rated capacity. This inherently limits the number of DG sites that can be connected to the system, because the conservative estimated value assumes that the thermal loading of the DG site is greater than it likely is at any given time. Monitoring and control will provide Toronto Hydro actual performance data from in-service connections for thermal loading values which will give a more precise view of existing conditions. This, in turn, will help enable Toronto Hydro to connect additional DG sites to the distribution system.

Monitoring and control also enables greater real-time visibility into the operating conditions of DG sites located in Toronto Hydro's service territory. Power system controllers need to know the aggregate generation connected to the system during planned or emergency load transfers. A power system controller must account for all DG during a load transfer because the increase in generation connected to the alternate feeder may cause short circuit capacity to be exceeded. The ability to remotely and automatically disconnect all DG sites on a feeder during planned or emergency load transfers is expected to simplify these operations as it would allow power system controllers to focus on restoration of customers' electricity rather than each individual DG site connected to a feeder.

Toronto Hydro's requirement for monitoring and control is modeled after requirements developed by the IESO. The IESO has developed DG monitoring and control guidelines with a focus on visibility, dispatch and forecasting capabilities for DG sites over 5 MW. Because of the volume and capacity of DG sites in Toronto Hydro's service territory (over 226 MW in aggregate), monitoring and control is required to connect additional DG projects and for grid management. This is also consistent with the requirements and practices of other LDCs.

Toronto Hydro's current monitoring and control process allows for the connection of DG sites through a Toronto Hydro communication interface as shown in Figure 4 below along with the standards it adheres to. Figure 5 shows a customer installation, which also adheres to Toronto Hydro standards.

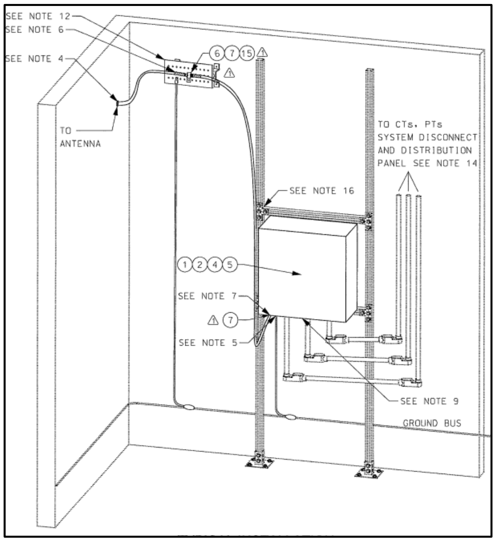


Figure 4: Toronto Hydro Communication Standard for DG Connections (left) and Communication Gateway Installed at Customer DG Site

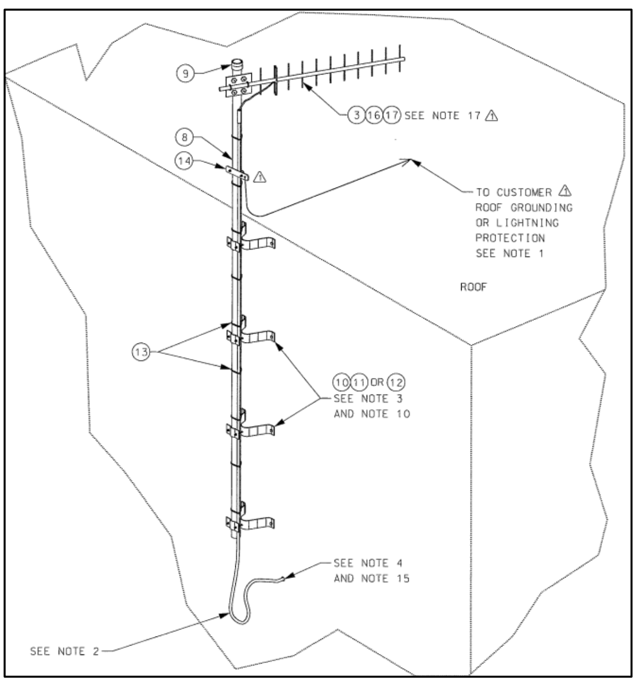


Figure 5: Toronto Hydro Communication Antenna Setup Standard (left) and at a Customer Site (right)

E5.5.4 Expenditure Plan

Table 7: Historical, Bridge & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Generation Protection, Monitoring, and Control	-	2.1	0.0	8.0	3.4	3.7	2.3	2.4	2.5	2.7

E5.5.4.1 2015-2019 Variance

1. Generation Protection

In 2015, Toronto Hydro had short circuit constraints on several station buses. To enable the connection of DG at these locations in a timely manner, a high-speed advanced protection scheme was proposed to mitigate the short circuit constraints. The advanced protection system consisted of installing 31 protection and control devices, along with 50-kilometres of fibre optic interface cable for Wiltshire TS, Basin TS and Leslie TS. However, the protection and control devices and fibre optic interface cable were never installed due to the reasons outlined below:

- During the design phase, due to the type of inverters selected by customers, the proposed advanced protection system at Leslie TS was no longer a viable solution. Instead of single, central type inverters, customers selected multiple, string inverters due to their lower costs. These string inverters do not possess the same functionality as their central inverter counterparts. Consequently, the proposed advanced protection systems would not relieve the short-circuit constraint.
- In 2016, Hydro One replaced end-of-life transformers at Wiltshire TS. This cancelled the program's planned work at that station as the specifications of the new transformers increased the short-circuit capability of the buses.
- The planned program work for Basin TS was cancelled due to the lack of progress on a customer's application for the installation of a 10 MW renewable energy generation project in the Basin TS area.
- An alternative solution for Leslie TS was the installation of a bus tie reactor. During the design phase for the bus tie reactor at Richview TS, the installation costs were determined to be more than originally anticipated.

For these reasons, Toronto Hydro intends to re-allocate roughly $0.8 million of the budget intended for advanced protection systems no longer required at Wiltshire TS, Leslie TS and Basin TS, to install bus tie reactors at Leslie TS and Richview TS in 2019.

2. Monitoring and Control

The monitoring and control work planned was delayed as a result of the need to customize and procure the monitoring and control systems to be installed on Toronto Hydro's distribution system (e.g. specifications, components). This delay has led to $1.8 million of work for MCS needs to be carried over into 2020. The high volume of existing and forecasted DG projects makes it challenging to accomplish this work by 2019. Therefore, both planned expenditure and unit values for MCS from 2017 to 2020 have been revised to reflect this new timeline for both existing DGs identified and new DGs.

Between 2012 and 2017, there were over 450 renewable generation connections where the customer purchased and installed MCS for their facilities. Pursuant to sections 3.3.2(g) and 3.3.3 of the DSC, the utility is responsible for costs incurred related to SCADA system design, construction and connection for renewable energy generation facilities. As a result, Toronto Hydro intends to reimburse past customers through the negotiation of a contractual agreement that allows Toronto Hydro to purchase the MCS, and receive assignment of any necessary access rights, warranties etc., which will facilitate Toronto Hydro's ongoing management of the MCS.

In late 2016, Toronto Hydro was able to purchase 211 MCS from its largest proponent of DG installations for $2.1 million. The remaining 240 MCS currently in the field are in the process of being audited by Toronto Hydro and an estimated $2.4 million will be reimbursed to customers in 2018 and 2019 for the purchase of these assets.

In addition to the purchase of 450 MCS from past customers, Toronto Hydro will need to install the radio communication link equipment required to facilitate the two way communication flow back to the Toronto Hydro Control Centre. An RFP process is currently underway to determine the contractor to perform the radio installations and work is expected to commence in early 2018 and be completed by 2020.

Toronto Hydro also forecasts and additional 169 renewable generation sites which will require MCS in 2018 and 2019. The installation of MCS is anticipated to cost $2.8 million and will occur as generation connection requests are received.

To better monitor and control the DGs connected to the grid, Toronto Hydro allocated $4.3 million in energy monitoring and control capabilities (DG SCADA Management), as mentioned in the 2015-2019 CIR. Due to the work delays mentioned above, the allocated budget was carried forward to 2018 and 2019 and increased to $6.6 million.

E5.5.4.2 2020-2024 Forecast

The Program is projected to cost $13.6 million over the 2020 to 2024 period which is consistent with the current forecast for the 2015-2019 period.

Table 8: Forecast Program Costs ($ Millions)

	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**
Generation Protection, Monitoring, and Control	3.7	2.3	2.4	2.5	2.7

1. Bus-Tie Reactors

To mitigate short circuit capacity limitations at transformer stations and prevent the rejection of DG connections, the installation of bus-tie reactors will be required to allow additional DG capacity. The installation of a bus-tie reactors has been successfully done by PowerStream, Guelph Hydro and Hydro One Networks Inc. ("Hydro One"). Based on these installations, the cost associated with the procurement and installation of a bus-tie reactor is approximately $1 million.

Based on forecasted DG proliferation outlined in section 3, Toronto Hydro anticipates that five bus-tie reactors will be required over the 2020 to 2024 period to alleviate short circuit capacity constraints. The station buses where bus tie reactors are proposed are shown in Table 9 below. Toronto Hydro plans to begin the design and construction of the first reactor in 2020 and complete installations of one reactor per year beginning in 2021.

Table 9: Bus Tie Reactor Installations

Station Name	Bus
Ellesmere TS	J
Esplanade TS	A1A2
Fairbank TS	YZ
Horner TS	BY
Sheppard TS	BY

Bus-tie reactor installations will occur in the order at which the need for short circuit capacity mitigation arises. As mentioned above, scheduling of DG installations is dependent on customer planning and timelines. Customers have cancelled or delayed DG projects in the past. As a result, Toronto Hydro will not move forward with a bus-tie reactor installation at a station until a firm commitment, in the form of an Offer to Connect (“OTC”), has been executed by both parties.

2. Monitoring & Control (“MCS”)

Pursuant to sections 3.3.2(g) and 3.3.3 of the DSC, Toronto Hydro is required to bear the costs related to communication systems (i.e. MCS) to accommodate the connection of renewable energy generation facilities. For all non-renewable energy generation facilities, the customer is responsible for costs relating to the MCS.

Based on current DG uptake and forecasted development, DG’s greater than and equal to 50 kW contribute to over 90 percent of DG capacity in the City of Toronto. Based on this and the current cost of MCS, Toronto Hydro decided that only installations greater than 50 kW would require an MCS. This threshold will provide Toronto Hydro with enough visibility and management of DG to properly achieve the objectives of the Program at a reasonable cost.

The timing and pacing of the installation of MCSs is driven by customer requests to connect DG to the distribution system. The estimated costs of the installation of MCSs over the 2020 to 2024 period is based on forecasts described in section 3. As explained above, MCSs are required for renewable DG facilities greater than 50 kW. The equipment and installation costs associated with the integration of a DG site into Toronto Hydro’s SCADA system is roughly $0.02 million and is based on historical DG MCS installations**.**

Toronto Hydro is dependent on the DG project and site owners to co-ordinate resources for the installation and commissioning of MCS equipment, which complicates work program scheduling. Due to the dependency on DG project/site owners, Toronto Hydro plans to complete the MCS work on an ad-hoc basis.

E5.5.4.3 Project Prioritization

The Program is driven by customer requests to connect DG to the distribution system and as such, are prioritized on a first come, first serve basis. DG customer timelines and deadlines are considered to minimize disruptions and allow for efficiencies, whenever possible.

E5.5.4.4 Cost Management

The selection of bus tie reactor projects are continuously evaluated to ensure that the investment is in the appropriate areas. For example, station bus short circuit levels are re-evaluated after each new connection application is received for that bus. Connection Impact Assessments ("CIA") are performed for each new DG and are the basis for determining if buses require short circuit relief.

Toronto Hydro is also regularly engaged with Hydro One and is made aware of future station transformer upgrades. As explained earlier, Wiltshire TS required short circuit relief when the last CIR was submitted, but in the time since, Hydro One upgraded the transformers, and the Generation Protection work was no longer required.

Through an RFP process, which included eleven vendors, a fixed cost for the MCS units has been negotiated with the successful vendor for the next five years. The installation of the MCS will be performed by an external contractor where performance and cost control incentives will be inserted in the contract.

For both segments, variance analyses will also be performed to identify areas for improvement and future cost management.

E5.5.5 Options Analysis

E5.5.5.1 Option 1: Status Quo (Do Nothing)

Under this option, Toronto Hydro will maintain the status quo and not install any bus tie reactors or MCSs. It allows Toronto Hydro to defer capital spending.

DG connections would continue to occur until the distribution system, in its current state, can no longer accept further generation due to short circuit, reverse power flow, and anti-islanding limitations. However, simply maintaining status quo would increase the number of DG application rejections and reduce reliability as Toronto Hydro would reach its operational and system design limits.

Additionally, the inability to have situational awareness and a more precise view into the operating conditions of all DG (through the installation of MCSs), would reduce the utility's capacity to connect additional DG facilities to the distribution system. Failure to connect all possible REG facilities to the Toronto Hydro distribution system would result in non-compliance with the requirements of Toronto

Hydro's distribution license, the DSC and the Electricity Act. As mentioned, as per Section 6.2.4 of the DSC, and sections 25.36 and 25.37 of the Electricity Act, Toronto Hydro is obligated to connect DG customers to its distribution system. Toronto Hydro is also obligated under section 6.1 of its Distribution License and section 26 of the Electricity Act to provide generators with non-discriminatory access to its distribution system and to provide priority access for renewable energy generation facilities. To comply with these obligations, Toronto Hydro evaluated two alternatives (major asset upgrades and the Generation Protection, Monitoring, and Control program) for addressing the system constraints that currently limit the utility's ability to connect the growing demand for DG on the system and safely and reliably manage DG connected to the distribution system.

Without active monitoring of DG facilities, there is an increased risk of unintentional islanding from DG sources thus reducing reliability on the system. This presents an increased risk to Toronto Hydro linespersons as they will be exposed to backfeed situations. Therefore, Toronto Hydro does not recommend this option.

E5.5.5.2 Option 2 (Selected Option): GPMC Program

The Program is the preferred alternative, as it is a much more timely and cost-effective solution and would allow for the continued integration, expanded visibility, and monitoring and control of DG connected to the Toronto Hydro distribution system.

In addition, Toronto Hydro expects that the Program's solutions will enable prediction of the amount of generation produced by DG connected to the distribution system, a capability that is not currently available to system planners. With performance data gathered through the Generation Protection, Monitoring, and Control program, Toronto Hydro will be able to make better informed decisions on the design and operation of the distribution system.

The overall cost of this option is $13.6 million over the 2020 to 2024 period.

E5.5.5.3 Option 3: Major Asset Upgrades

As an alternative to the work planned within the Program, Toronto Hydro could address DG requirements via major asset upgrades at transformer stations where short circuit capacity constraints exist. Assets to be upgraded include power transformers and switchgear. Monitoring and control equipment would also be installed as part of this option.

However, the entire process may take up to five years, which is outside the timeframe by which short circuit limitations would need to be resolved. The internal engineering design and approval process followed by discussions held with Hydro One to obtain the necessary approvals can take up to 2 years. Once the approval process is complete, the major assets associated with this program have 1-2 year material lead-times, and may take more than additional year to install. Additionally, Hydro One owns these major assets, and to replace them outside of their planning cycle would require Toronto Hydro to pay approximately $10-15 million for each station bus upgrade.

E5.5.6 Continuous Improvement and Productivity

With the implementation of MCS, Toronto Hydro will have access to real time data for all generation sites greater than 50 kW. The information obtained from the MCS and the Energy Monitoring and Control Capabilities can be integrated with distribution system analysis software to produce simulations and reports in a more timely, accurate and efficient manner. This would result in CIA's being completed within the prescribed time at a higher rate.

E5.5.7 Execution Risks & Mitigation

The Generation Protection segment may be exposed to the following risks: (i) limited technical labour resources to install systems, (ii) conflicting timing and an inability to coordinate with other capital projects and planned maintenance work of station assets; and (iii) difficulties in transferring existing customer loads to standby feeders. To mitigate these risks, Toronto Hydro plans to advance the planning between relevant Toronto Hydro departments to help address the issues and constraints related to labour availability and general capacity (i.e. load and communication network); and will plan this work during off-peak periods to mitigate potential impacts to standby feeders.

With respect to the Monitoring and Control segment, communication infrastructure (i.e. radio network) may need to be expanded or upgraded to handle high volume of DG connections. Therefore, Toronto Hydro will ensure adequate capacity exists for forecasted DG, and will proactively upgrade radio systems before capacity concerns arise.

E6 System Renewal Investments

E6.1 Area Conversions

E6.2 Underground System Renewal - Horseshoe

E6.3 Underground System Renewal - Downtown

E6.4 Network System Renewal

E6.5 Overhead System Renewal

E6.6 Stations Renewal

E6.7 Reactive and Corrective Capital

E6.1 Area Conversions

E6.1.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 185.7	**2020-2024 Cost ($M):** 220.8
Segments: Rear Lot Conversion, Box Construction Conversion	
Trigger Driver: Functional Obsolescence	
Outcomes: Reliability, Safety, Customer Service, Public Policy	

The Area Conversions program ("the Program") funds the replacement of functionally obsolete 4.16 kV distribution system designs with updated standard 13.8 kV and 27.6 kV lines; focusing mainly on two unique legacy 4.16 kV asset designs known as Rear Lot Construction and Box Construction. These assets serve residential customers in the Horseshoe region, and small commercial and residential customers along main streets in the downtown area of pre-amalgamation City of Toronto. The Program is designed to address below-average customer reliability outcomes, mitigate public and employee safety risks and other operational and customer service deficiencies posed by these legacy and aging assets.

The Program is grouped into the segments summarized below and is a continuation of the renewal activities described in Toronto Hydro's 2015-2019 Distribution System Plan.[1]

- **Rear Lot Conversion:** this segment continues the replacement of end-of-life overhead and underground assets installed in the backyard, or rear lot, with standard front lot underground supply. Typically installed over 40 years ago, these assets serving residential customers in the Horseshoe region of Toronto present significant safety and reliability risks in the event of failure. Toronto Hydro is on track to successfully upgrade approximately 2,400 rear lot customers to front lot 27.6 kV underground services during the 2015-2019 period. Toronto Hydro's overall objective for this segment is to mitigate and eventually eliminate rear lot equipment failure risk, as failures result in long duration outages and safety risks to customers and crews given the nature of the rear lot plant. To this end, Toronto Hydro plans to spend $109.3 million to convert an additional 2,350 customers over 2020-2024. This

[1] EB-2014-0116, Exhibit 2B, Section E6.6 and E6.7

pacing is needed to continue mitigating the reliability and safety risks associated with rear lot assets.

- **Box Construction Conversion:** a continuation of Toronto Hydro's plan to eliminate aging box construction feeders from the pre-amalgamation City of Toronto. These overhead feeders are located along main streets in the downtown area and serve residential neighbourhoods and small commercial customers. Toronto Hydro no longer builds the system to this standard due to safety compliance, reliability, access, equipment, capacity, and procurement issues. The congested, box-like framing of the circuits prevents crews from establishing safe limits of approach to live conductors, which in turn restricts operations and leads to longer power restoration times for customers when compared to modern overhead standards. During the 2015-2019 period, Toronto Hydro plans to convert approximately 5,300 poles to standard 13.8 kV overhead configurations. To eliminate all remaining box construction by 2026, Toronto Hydro plans to spend $107.3 million to convert approximately 2,600 more poles by 2024. This pacing is needed to continue mitigating the reliability and safety risks associated with box construction feeders.

Toronto Hydro plans to invest $220.8 million in the Area Conversions program in 2020-2024, which is an 18.9 percent increase over projected 2015-2019 spending in this Program (including forecasted inflation). This pace of investment is necessary to mitigate reliability and safety risks of these functionally obsolete system designs.

E6.1.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Eliminating the risk of long (i.e. 5 to 40+ hours) rear lot outages for approximately 2,350 residential customers in the worst performing rear lot areas. ○ Improving average outage restoration times for 22,700 residential and small business customers downtown by converting 2,600 aging and obsolete poles.

<table>
<tr><td>Safety</td><td>Contributes to improving Toronto Hydro’s Box Construction Conversion Measure, public safety performance and employee safety by mitigating safety risks that are unique to obsolete rear lot and box construction designs. Specifically:
Eliminate public safety risks to address compliance issues (i.e. relating to Electric Utility Safety Rule 129 - safe limits of approach, Canadian Standards Association and Electrical Safety Authority) associated with legacy box construction feeders by replacing approximately three quarters of remaining box construction assets by 2024, with a target of 100 percent elimination by 2026.
Maintain the pace of rear lot conversion in order to mitigate the risk of equipment failure and safety issues arising from potential crew and public exposure to rear lot access.</td></tr>
<tr><td>Customer Service</td><td>Contributes to Toronto Hydro’s customer service performance and customer satisfaction by:
Minimizing the need for unplanned crew access of customer property by converting approximately 2,350 residential rear lot customers to front lot service.
Improving the speed and cost-efficiency of customer grid access (including generation and electric vehicle access) in high-growth areas of downtown Toronto by converting approximately 2,600 poles (containing approximately 100 kilometres of low capacity and low clearance box construction feeders) to more efficient and flexible higher voltage standards.
Reducing public traffic disruptions on main city streets from an operational and maintenance perspective (i.e. less frequent repairs and visits) once the box construction is converted.</td></tr>
<tr><td>Environment</td><td>Contributes to improving Toronto Hydro’s Spills of oil Containing PCBs measure by eliminating all PCB at-risk transformers on the box construction and rear lot plant by the end of 2024.</td></tr>
</table>

E6.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Functional Obsolescence
Secondary Driver(s)	Reliability, Safety

This Program addresses distribution assets with legacy design features that result in substandard reliability performance for customers, safety risks for crews and the public, and other undesirable outcomes. For these reasons, Toronto Hydro considers the assets to be functionally obsolete. As these assets age and deteriorate, risk of failure increases and Toronto Hydro prioritizes them for replacement in order to maintain acceptable reliability outcomes and mitigate exposure to safety risks by utility crews and the public.

Rebuilding these feeders on a like-for-like basis is not a viable option due to the substandard performance, material availability and compatibility issues, and safety risks inherent to the existing designs. Furthermore, as discussed in Exhibit 2B Section D3.2.1, Toronto Hydro is gradually phasing out its 4.16 kV distribution system in favour of the more efficient 13.8 kV and 27.6 kV systems, which are also better suited to efficiently handle urban growth and development in the City of Toronto.

The following sections provide more detailed information about the drivers of work in each of the Rear Lot Conversion and Box Construction Conversion segments.

E6.1.3.1 Rear Lot Conversion

The Rear Lot Conversion segment is a continuation of Toronto Hydro's plan to convert and re-supply rear lot customers with underground front lot services. As illustrated in Figure 1 below, the replacement front lot design supplies customers through lateral underground 27.6 kV primary circuits along the roadways with predominantly padmounted transformers. Once customers are connected to the improved configuration, all remaining rear lot assets are removed to eliminate safety risks.

Figure 1: Legacy rear lot supply vs. replacement front lot supply.

Rear Lot Conversion is necessary to address reliability and safety risks that are caused or exacerbated by poor accessibility and physical encroachments inherent to the existing rear lot plant location.

1. Rear Lot Reliability Issues

Rear lot plant was generally built in the 1960s and a large portion of these assets have been operating for approximately 40 - 60 years. As the plant ages, the risk of outages caused by equipment failure increases. Notably, rear lot plant consistently experiences longer duration outages than the average Toronto Hydro feeder (as illustrated in Figure 2 below), primarily due to difficulty experienced by crews in locating faults and safely accessing and repairing equipment.

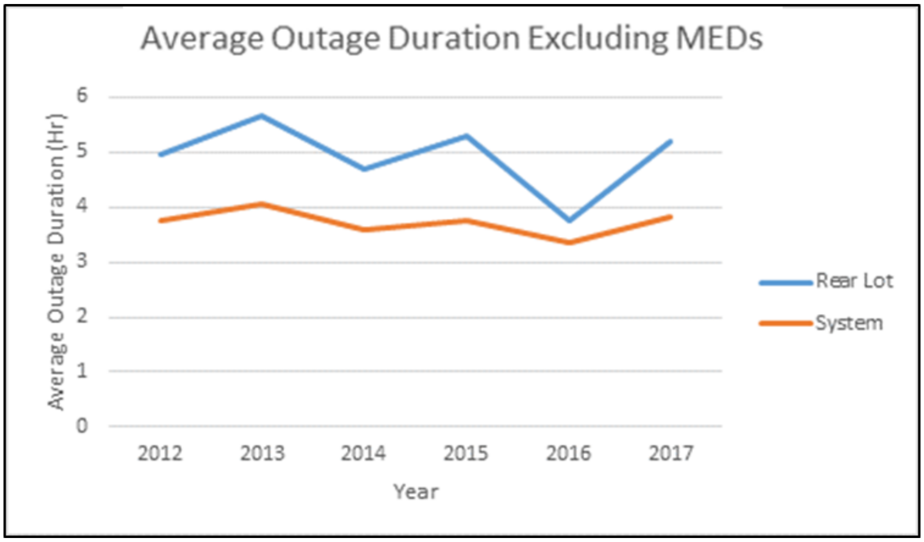


Figure 2: Average Outage Duration Excluding Major Event Days ("MEDs"): Rear Lot vs. All Feeders

On average, over the 2012-2017 period, outages on rear lot feeders were 1.3 hours longer than outages on the system as a whole.

The relatively poor performance of Toronto Hydro's rear lot distribution system is further demonstrated by the number of incidents resulting in loss of service to rear lot customers for at least one day. The location of the infrastructure (i.e. in backyards, often in close proximity to trees and vegetation), and its deteriorating condition make rear lot distribution particularly vulnerable during storms and other severe weather events. Table 4 below contains examples of outages that have occurred, many of which occurred during storm conditions such as on Major Event Days ("MEDs"). In all cases, accessibility challenges contributed to prolonged outage durations. Residential customers have on average demonstrated a tolerance for one to three short outages per year (particularly during non-critical times of use) before customer satisfaction level begins to drop. However, nearly all customers believe that an outage lasting more than five hours is unreasonable.[2] Many outages on rear lot feeders greatly exceed five hours, as shown in Table 4 below.

[2] See: Exhibit 2B Section E2.3

Table 4: Long Duration Events on Rear Lot Feeders

0.6	Station	Feeder	Cause	Duration (hrs)	MED (Y/N)
21-Dec-13	*HARTSDALE MS*	HDF1	Freezing Rain Extreme / Adverse Weather	90.6	Y
09-Feb-14	*HARTSDALE MS*	HDF2	Cable - Primary / Defective Equipment	47.9	N
20-Aug-09	*MILL MS*	LFF1	Wind Extreme / Adverse Weather	44.7	Y
19-Jul-13	*BLACKFRIAR MS*	VCF1	Wind Extreme / Adverse Weather	44.6	N
24-Nov-14	*MILL MS*	LFF2	Cable - Primary / Defective Equipment	43.8	Y
24-Dec-13	*ISLINGTON MS*	PAF3	Freezing Rain Extreme / Adverse Weather	42.8	Y
22-Dec-13	*HIGHBURY MS*	TAF4	Freezing Rain Extreme / Adverse Weather	40.1	Y
22-Dec-13	*HARTSDALE MS*	HDF3	Freezing Rain Extreme / Adverse Weather	37.8	Y
19-Jul-13	*LONGFIELD MS*	BHF1	Wind Extreme / Adverse Weather	34.5	N
22-Dec-13	*HARTSDALE MS*	HDF2	Freezing Rain Extreme / Adverse Weather	31.1	Y
15-Mar-10	*ALBION MS*	MGF1	Cable - Primary / Defective Equipment	28.0	N
05-May-17	*ALBION MS*	MGF1	Cable - Primary / Defective Equipment	26.3	N
01-Jun-12	*NEILSON DR MS*	BAF1	Wind Extreme / Adverse Weather	23.9	N
19-Jul-13	*HIGHBURY MS*	TAF4	Wind Extreme / Adverse Weather	23.5	N
09-May-17	*ALBION MS*	MGF1	Cable - Primary / Defective Equipment	23.1	N
09-Aug-09	*ISLINGTON MS*	PAF3	Lightning	23.1	N
26-Apr-15	*ALBION MS*	MGF1	Cable - Primary / Defective Equipment	22.7	N
23-Dec-13	*ROSETHORNE MS*	SBF3	Adverse Weather / Tree Contacts	21.5	Y

Rear lot reliability issues are caused by the obsolete design of the plant and the challenging environment in which it operates. As an example, Figure 3 below shows the Jamestown residential rear lot area which Toronto Hydro plans to convert. The primary lateral, shown in red, branches off of the main feeder circuit, enters the neighbourhood in between two houses, and is subsequently routed between the rear of residential properties. The secondary circuit, shown in green, branches off and crosses customer properties to the meter base supplying each residence.

Figure 3: Lateral Circuit Configuration - Jamestown Rear Lot Neighbourhood

Outage restoration issues stem from the following factors, which are common to rear lot areas like the one depicted in Figure 3:

- **Manual fault detection:** the vast majority of rear lot feeders operate at 4.16 kV and therefore lack fault detection and isolation technologies like SCADA-mate switches that are standard in up-to-date distribution systems.
- **Accessibility/Visibility:** in a typical rear lot area such as Jamestown, poor access and visibility exacerbate a fault situation, contributing to prolonged outages and inefficient use of resources during fault location and outage restoration. Limited access can restrict the use of

standard equipment such as bucket trucks, drilling machines and other machinery and implements. This means that heavy materials such as poles and transformers must be manually carried or even hoisted over the residence by crane. For overhead feeders, specialized reactive crews are needed to physically climb the poles during repairs. For underground feeders, crews must manually dig trenches to repair direct-buried cables.

- **Obstructions:** spatial constraints like trees and fences may prevent crews from walking on an uninterrupted path along the feeder to locate the fault, forcing them to enter multiple residential backyards along the circuit. Once the fault is located, crews often face the difficult task of repairing the fault and restoring service while being mindful of a customer's private property and compliance with electrical safety regulations. For instance, Figure 3 shows the presence of mature trees and swimming pools in the vicinity of Toronto Hydro plant.
- **Non-standard equipment:** the top left area of Figure 3 shows the location of obsolete T-splices (used to split underground distribution circuits). Any outage downstream of a T-splice will affect all customers on the main branch circuit. This is not the case in modern power system design where fuses prevent this undesirable outcome.

The Jamestown area demonstrates the extent to which reliability can be an issue for rear lots with 15 outages over 2012-2017, the majority of which lasted longer than five hours. Table 5 below shows the number and duration of outages in the Jamestown area from 2012 to 2017. This level of service would be considered unacceptable to most customers.

Table 5: Jamestown Community Outage Stats 2012-2017

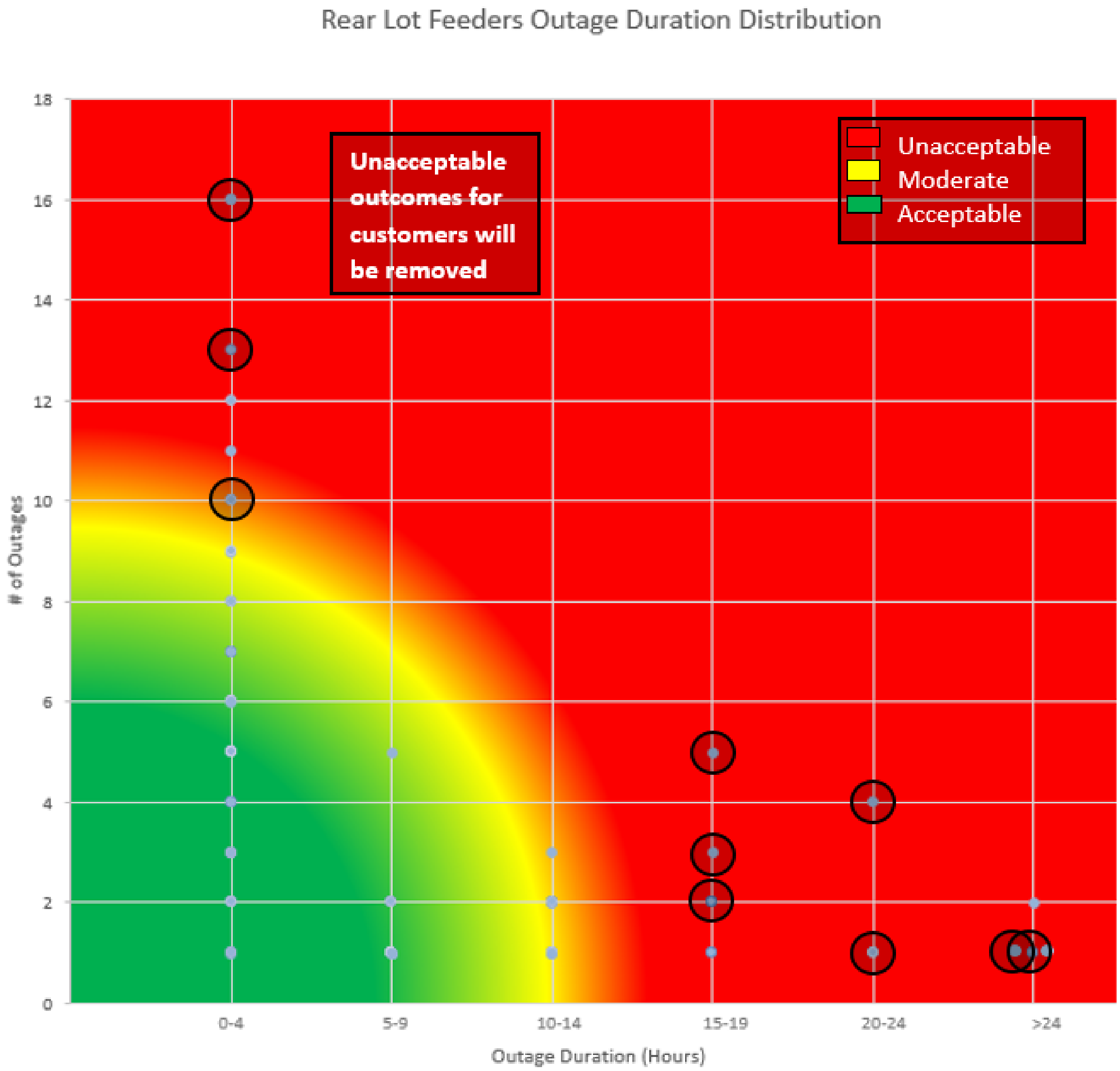
Outage Duration in Hours	Number of Outages
1 – 5	3
6 – 10	1
11 – 15	2
16 – 20	4
21 – 25	4
26 – 30	1

During the 2020-2024 period, Toronto Hydro plans to convert and rebuild the Jamestown area and seven other areas. All of these areas have experienced at least three outages from 2012 to 2017. Like most communities containing rear-lot distribution, 47 percent of the rear-lot poles in these areas have surpassed their useful life and 51 percent of the poles are showing moderate to material deterioration as determined by Toronto Hydro's Asset Condition Assessment methodology. Table 6 shows the breakdown of poles by asset condition category for all rear lot poles.

Table 6: ACA Comparison of Poles

Pole Asset Condition Class	% of Assets per Class (2017)
HI1 – Good Condition	20%
HI2 – Minor Deterioration	2%
HI3 – Moderate Deterioration	33%
HI4 – Material Deterioration	29%
HI5 – End of Life	4%
ACA Data Unavailable	12%

Converting an entire rear lot area is a complex and lengthy undertaking that must be carefully sequenced and executed over multiple years. Given the amount and age of the remaining plant, it is necessary for Toronto Hydro to continue with a steady pace of proactive Rear Lot Conversion, while prioritizing those areas that are experiencing the worst reliability performance. To this end, Toronto Hydro has ranked feeders according to their reliability performance. The following 'heat map' (Figure 4) shows all rear lot outages from 2012-2017 with dots representing a recorded outage in the rear lot system. Based on the Toronto Hydro's 2015 Utility Pulse Survey the dots/outages indicated in the red area are considered unacceptable by customers. The circles overlapping the dots in the chart indicate which feeders have been targeted for conversion for the 2020-2024 period. As is evident from the chart, the proposed rear lot plan will continue to address those areas where customers are experiencing the worst service.



1 **Figure 4: Heat Map of all 2012-2017 rear lot outages**

2 ## 2. Rear Lot Safety Issues

3 Equally important in the Rear Lot Conversion segment is the need to prudently manage safety risks
4 to crews and the public. These risks are generally caused by the same operational factors and field
5 conditions that contribute to long-duration outages on the rear lot system.

As mentioned above, as assets age and deteriorate, the risk of failure increases along with the likelihood that Toronto Hydro crews will need to access and repair rear lot equipment on a reactive basis. This exposes crew members to potential safety risks such as:

- tight work spaces;
- poor visibility at night;
- poor footing in the winter;
- the need to manually transport equipment to poorly accessible job sites;
- the need to climb poles that may be in poor condition due to rot, animal damage, or other environmental factors and may require additional stabilization; and
- obstacles (e.g. fences, sheds, and pools) and clearances between Toronto Hydro's distribution equipment and customer property that do not meet minimum requirements.

An incident demonstrating these safety risks occurred in 2014. Toronto Hydro dispatched a two-member crew following notification of a fallen tree at the rear of a house that had a steep slope covered with snow and ice. One crew member walked up the slope to locate the cable attachment and slipped and injured his right elbow and hip. The following pictures (Figure 5 and Figure 6) show similar examples of safety challenges faced by Toronto Hydro crews.

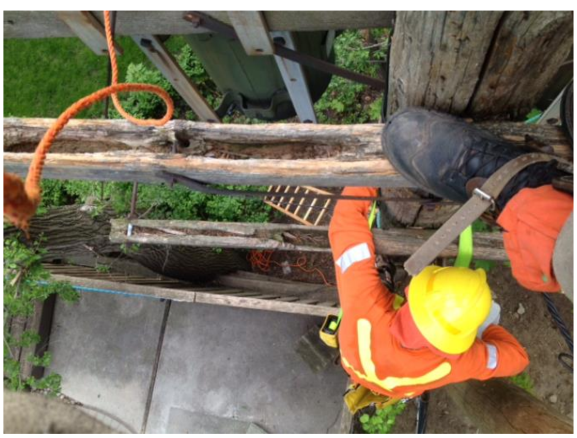


Figure 5: Field crews replacing failed transformer on pole in poor condition

Figure 6: Poor condition pole in close proximity to swimming pool

In addition to access issues, mature tree canopy cover (which sometimes requires immediate trimming on site) and poorly constructed landscapes can cause visibility issues in rear lots. Other than contributing to extended outage durations, reduced visibility is a safety concern for crews executing electrical work. The need to manage crew safety risk is one of the primary reasons that Toronto Hydro needs to minimize the aggregate risk of rear lot asset failure.

Public safety is also a key consideration in respect of the Rear Lot Conversion segment. Rear lot assets installed in the 1960s do not adequately account for access needs related to modern growth of neighbourhoods, expansions of homes and live line clearances. Locations have been identified where live wires are in close proximity to customer homes, sheds, fences, and pools. Exposed wires have also been found at riser poles that have been deteriorating or moved over time due to direct contact. These locations do not comply with (e.g. clearances defined in) the Electrical Utilities Safety Rules ("EUSR") rule 129, and applicable standards of the Canadian Standards Association ("CSA"), Toronto Hydro, and the Electrical Safety Authority ("ESA") (i.e. ESA standard 75-708). Furthermore, when a pole deteriorates or leans, a transformer leaks oil or catches fire, or porcelain insulators break, the safety risk to the public increases when installations are in proximity to the those structures. Figure 7 and Figure 8 illustrate some of these clearance issues.

Limits of Approach

1. Rear lot overhead poles, transformers, and live conductors in close proximity to physical properties
2. Obsolete 4.16kV transformers
3. Aged and tilted cross arms and leaning poles
4. Mature vegetation. trees and vines present risk of contact
5. Transformers are typically mounted lower on the poles, in line with windows. If a transformer were to catastrophically fail it may be a hazard to the public or protrude into windows

Figure 7: Energized transformer and pole line close to home and covered in vegetation

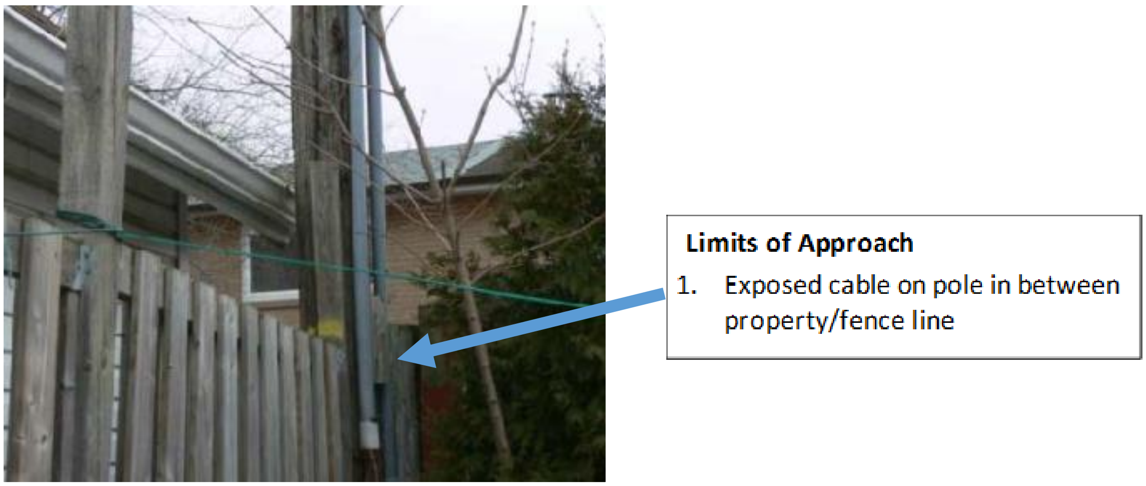


Figure 8: Fence built on easement and exposed cable from broken guard

3. Other Rear Lot Issues

Toronto Hydro is aware of 190 transformers at risk of containing PCBs in areas addressed by the Rear Lot program. This accounts for roughly half of the transformers in the rear lot area as of 2017. Rear Lot projects include the replacement of PCB at-risk transformers. Through the Area Conversion program, Toronto Hydro is proposing to eliminate approximately 100 PCB at-risk transformers by 2024 as part of the planned projects in the rear-lot system. The remaining PCB at-risk transformers will be addressed as part of other programs. This plan supports Toronto Hydro’s continuous reduction of PCB-contaminated oil leaks.

E6.1.3.2 Box Construction Conversion

The Box Construction Conversion segment is a continuation of Toronto Hydro’s plan to convert functionally obsolete box construction feeders to the standard 13.8 kV armless overhead construction. Box construction is a legacy 4.16 kV overhead design. Due to a number of safety, reliability, access, equipment, capacity, and procurement issues, Toronto Hydro no longer builds the system to this standard. As discussed in detail below, safety compliance issues also drive the need to eliminate box construction from the system. Figure 9 shows the before and after of a completed Box Construction Conversion project from 2013.

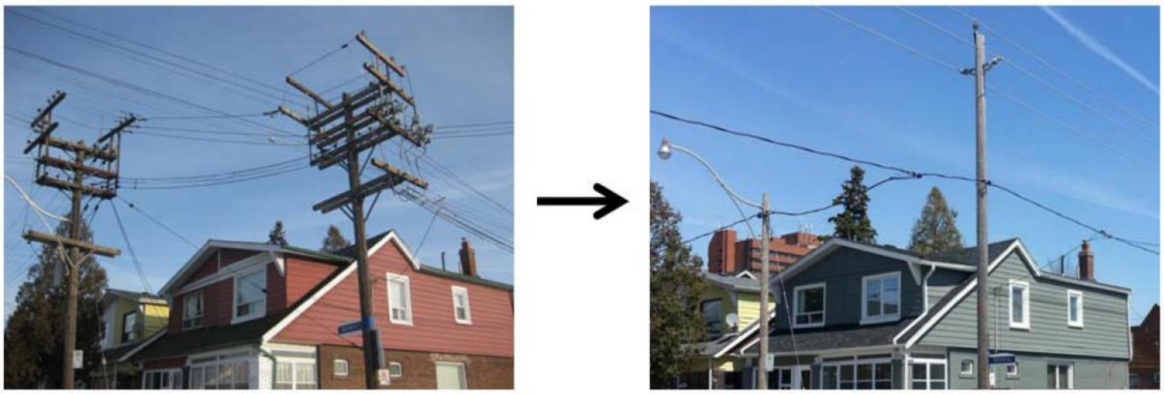


Figure 9: Actual conversion project in the Byron Avenue and Danforth Avenue area. The photograph on the left shows the 4.16 kV box construction feeder prior to conversion. The completed project is shown in the photograph on the right, where all 4 kV box construction has been removed and replaced with a 13.8 kV overhead feeder.

4. Box Construction Safety Issues

The industry-wide practice for overhead pole maintenance is to access circuits using bucket trucks. However, the congested nature of the obsolete box construction design means that most box construction circuits cannot be accessed safely in this manner. Instead, workers must climb these poles, which increases the safety risks they face. Such risks include potential injury from the additional physical exertion from climbing, an elevated falling hazard when compared to the use of a bucket truck, and an increased risk of electrical contact due to the inability to use the insulated aerial boom and bucket liner found on bucket trucks.

Furthermore, Toronto Hydro crews working in close proximity to box construction lines can have difficulty conforming to the working clearances defined in EUSR Rule 129.[3] The required 15 centimeter air gap between people (or tools) and energized conductors cannot always be achieved. Compliance with these safety rules requires adjustments to normal work operations, such as maneuvering around poles in a bucket truck and closing off road access to multiple poles. This in turn contributes to the lengthy outage restoration times discussed below.

[3] Electric Utility Safety Rule 129 - safe limits of approach, Canadian Standards Association and Electrical Safety Authority, Page 34 https://www.ihsa.ca/PDFs/Products/Id/RB-ELEC.pdf

Another crew safety risk is caused by certain obsolete equipment used on box construction feeders. One example is the Positect switch, a non-standard fused switch that is operated by hand, putting field crews in the flash zone of the switch (i.e. an “arc flash” electrical hazard). Positect switches are being removed as part of Box Construction Conversion.

Similar to rear lot lines, some box construction lines fail to comply with contemporary clearance rules resulting in potential safety risks to the public. Live wires have been found in close proximity to customer homes, windows and balconies. Some buildings are within two to three metres of live lines due to the legacy design parameters of box construction. These limits of approach are not consistent with clearance requirements, namely those set out in EUSR rule 129 as well as standards adopted by the CSA, Toronto Hydro, and the ESA (standard 75-708: *Clearances of conductors from buildings*). As such, this issue must be addressed by replacing box construction with updated standard 13.8 kV construction as part of plant renewal. As a visual example, Figure 10 below illustrates a box construction clearance issue.

Limits of Approach

Box Construction poles house conductors with wide cross-arms which cause conductors to be spaced further away from poles and closer to buildings and windows compared to armless construction standards. This photo shows a few of the many issues associated with the obsolete design of box construction:

1. Close proximity of live lines to public and public structures due to box physical properties
2. Aged and tilted cross arms and leaning poles
3. Transformers are typically mounted lower on the Box poles, in line with windows. If a transformer were to catastrophically fail it may cause the windows to break and endanger the public.

Figure 10: Example of Box Construction clearance issues

5. Box Construction Reliability Issues

The existing box construction plant is on average over 50 years old and has exhibited a decline in reliability performance relative to the system as a whole, as shown in Figure 11 and Figure 12 below.

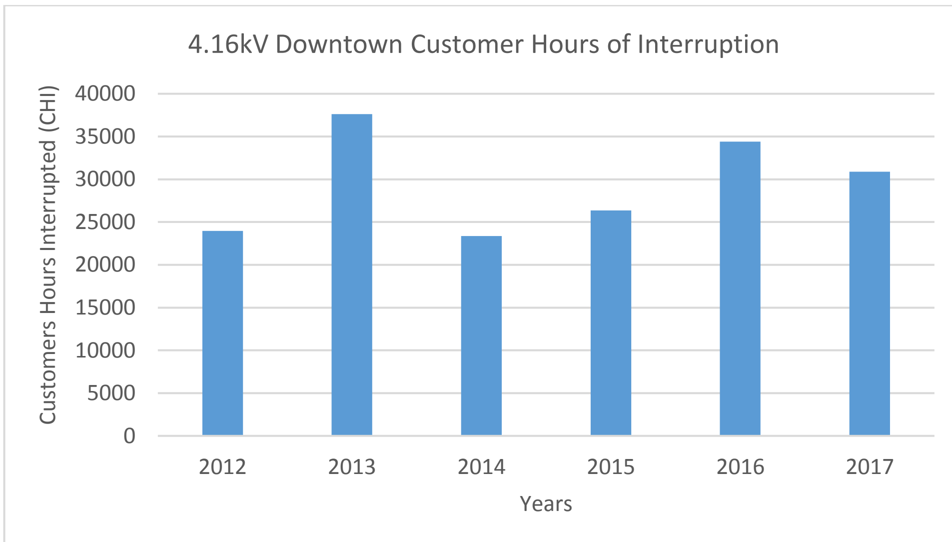


Figure 11: Historical Reliability for Feeders Proposed for Conversion

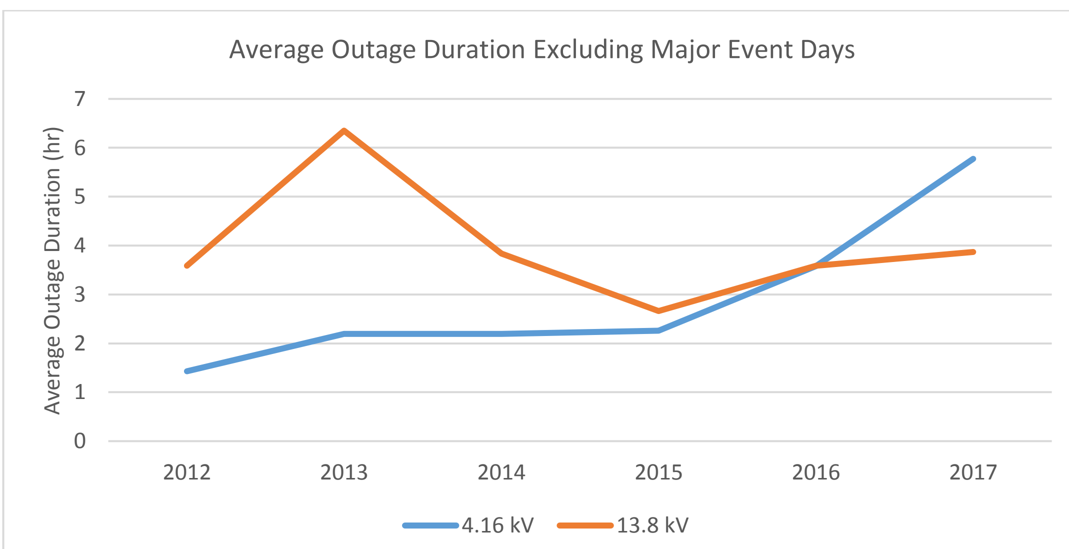


Figure 12: Average Outage Duration for 4.16 kV and 13.8 kV Systems

Between 2012 and 2017, there were 81 outages (excluding MEDs) directly associated with box construction. The top causes of these outages include defective primary overhead and underground equipment failure, adverse weather, tree contacts, and extreme rain and wind. Box construction assets are generally past their useful life and are less capable of withstanding strong winds and contact from trees during storms compared to new 13.8 kV overhead feeders in the downtown area.

Like rear lot plant, box construction feeders tend to require longer restoration times than feeders built to up-to-date standards. The reasons for this are similar to those that drive long duration outages in the rear lot, including: the need for manual fault location; clearance, access and safety issues that slow down operations; and during reactive equipment replacement, the need to integrate newer standard equipment in a unique configuration that is compatible with the existing box construction design.

Toronto Hydro expects reliability to worsen further as assets continue to deteriorate. As shown in Table 7, currently approximately half (or more) of poles, transformers, and switches associated with box construction are past their useful life. Based on inspection and maintenance reports, these assets exhibit moderate to material deterioration.

Table 7: Percentage of Box Construction Assets past Useful Life

Asset	Percentage (%)
Transformers	39%
Switches	60%
Poles	49%

Where box construction assets have already failed, the inability to source obsolete replacement equipment has often forced crews to repair the system using temporary and non-standard solutions. As time passes, workforce retirements will continue to diminish the pool of employees who are experienced in repairing box construction feeders, which further underscores the need to eliminate box construction on a firm timeline.

6. Other Box Construction Issues: Efficiency, Capacity, and PCBs

Box construction feeders are part of the 4.16 kV system. As noted in Exhibit 2B Section D3.2.1, Toronto Hydro is gradually phasing out 4.16 kV in favour of 13.8 kV and 27.6 kV standards. Lower voltage 4.16 kV feeders are less energy efficient[4], have significantly lower capacity, and are less flexible in accommodating new load than the 13.8 kV feeders that replace box construction. In addition to the environmental and cost benefits of reducing line losses, upgrading 4.16 kV to 13.8 kV feeders will allow Toronto Hydro to more efficiently accommodate new large customers, renewable generation connections, and electric vehicle charging stations in high-growth areas of downtown Toronto. Without these upgrades, Toronto Hydro may need to connect larger loads using alternative means, such as running a new feeder or extending an existing feeder. This requires additional time and resources and may increase the connection costs for customers and developers.

Finally, there are currently 400 PCB at-risk transformers on box construction feeders. This accounts for a third of the transformers on box construction feeders as of 2017. The Box Construction Conversion segment will eliminate an estimated 325 PCB at-risk transformers by 2024 through the planned projects, supporting continuous reductions in PCB-contaminated oil leaks. While PCB at-risk transformers are not the primary driver for Box Construction Conversion, they are an additional consideration reinforcing Toronto Hydro's plan.

E6.1.4 Expenditure Plan

Table 8 below summarizes the historical, bridge and forecast spending for this Program. After examining program need and establishing pacing strategies for each segment, Toronto Hydro developed the expenditure plan details by identifying and prioritizing project boundaries in each segment for the 2020-2024 period and applying volume and cost assumptions based on historical accomplishments. The cost estimates use the historical average cost per customer (Rear Lot) and cost per pole converted (Box Construction) to extrapolate long-term program costs based on high-level project attributes. The forecast Rear Lot Conversion and Box Construction Conversion spending is relatively steady over 2020-2024,with the later decreasing slightly compared to 2015-2019 levels due to the pace of work slowing as the utility gets closer to eliminating all box construction by 2026.

[4] By converting 4.16 kV feeders to 13.8 kV, distribution line losses may be reduced.

Table 8: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Rear-Lot Conversion	26.7	14.5	8.2	5.7	10.0	18.8	26.3	25.2	28.3	14.9
Box Construction Conversion	19.6	13.6	18.7	34.3	34.4	22.7	20.8	21.1	22.0	20.7
Total	**46.3**	**28.1**	**26.9**	**40.0**	**44.4**	**41.4**	**47.2**	**46.3**	**50.4**	**35.6**

E6.1.4.1 Rear Lot Conversion Expenditure Plan

Toronto Hydro invested $49.4 million in rear lot conversion projects between 2015 and 2017, resulting in the conversion of 2,090 customers from aging rear lot service to safer and more reliable front lot underground service. The utility plans to invest $65.1 million by the end of 2019 to convert approximately 2,400 customers over the 2015-2019 period. Spending was approximately $16 million higher than forecast for 2015 and 2016 due to a higher than expected number of projects carried over into the 2015-2019 period and due to project costs variances that occurred as projects progressed from high level estimates to detailed designs (e.g. changes in the design configuration required by the actual conditions at the project site or project scope[5]).

Toronto Hydro plans to invest $113.5 million over the 2020-2024 period to convert approximately an additional 2,350 rear lot customers in the worst performing areas to mitigate the various risks that have been discussed above (including the risk of prolonged outages, ranging from 5 to more than 40 hours). This rate of spending reflects the need to keep up with the pace of rear lot aging and the substantial amount of rear lot plant remaining. Over the long-term, by limiting and reducing the volume of end-of-life rear lot assets, Toronto Hydro aims to prudently manage the safety and reliability risks associated with their failure. Figure 13 shows the estimated rate of conversion from 2015 to 2025.

[5] Project scope changes occurred as designers conducted site visits, identifying that additional or fewer assets and labour were required to execute the job based on asset condition and configuration.

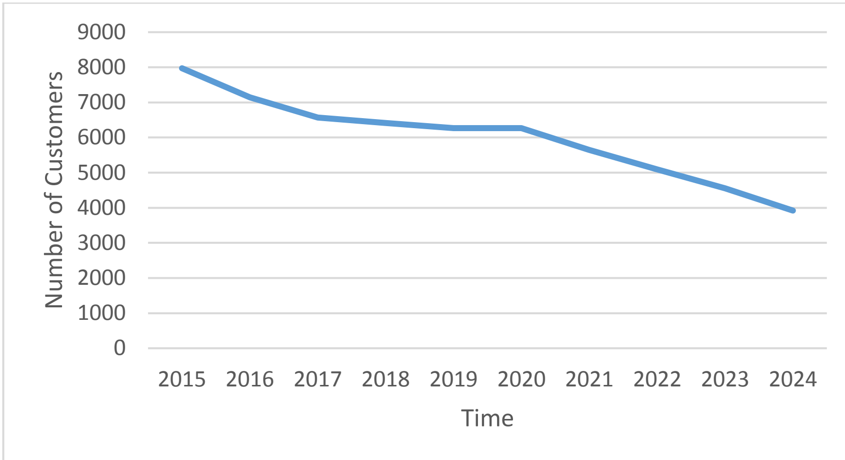


Figure 13: Rate of Conversion of Rear Lot Customers (2015-2024)

Rear Lot Conversion is not a like-for-like replacement activity. Projects are therefore difficult to estimate on an installed asset basis without first completing a preliminary design of the new front lot underground feeder, which does not take place until closer to project execution. As such, Toronto Hydro has used a historical average cost per customer to parametrically estimate 2020-2024 costs for the prioritized project areas. To develop the cost per customer, Toronto Hydro examined three major rear lot areas, consisting of eight projects completed in recent years.

Toronto Hydro applied an average cost of $0.036 million per customer plus inflation and engineering and support costs in developing the segment cost forecasts for the 2020-2024 period. Note that costs for 2018-2019 are based on estimates for the projects proposed over that period and not the aforementioned average cost per customer. The amount required per annum will vary year-over-year based on the timing of each project over multiple calendar years. Toronto Hydro designs and plans projects using a phased approach based on feeder configuration and customer count (e.g. Project Thorncrest with 600 customers involved three phases with 200 customers each) and ensures that civil construction is completed in one year and then followed in the next year by electrical construction. Civil work costs approximately twice as much as electrical and therefore annual costs (total and per customer conversion completed) will vary depending on the balance of civil and electrical work completed each year.

The average duration of a full 200-customer phase rear lot conversion construction project is approximately 13 months. By completing projects in a staggered fashion instead of addressing all the customers at one time, Toronto Hydro can improve reliability by reducing the time until the first customers will start benefitting from the conversion. For example, if Project Thorncrest were to be done as single phase project it would take about 39 months for all 600 customers to be fully converted and during that time all those customers would continue to experience a higher risk of outages on the legacy equipment. However, when done in phases, the first 200 customers would be converted after only 13 months and the next 200 customers after 26 months. This way only a third of the customers would be at higher risk of outages throughout the full project period. Minimizing the risk of outages minimizes the risk of added costs and long duration outages as our crews can spend less time restoring power on legacy equipment.

Rear Lot Conversion projects are prioritized based on asset reliability, equipment condition, and coordination with planned city road work. Generally, the worst performing feeders are targeted for completion first. To reduce costs, Toronto Hydro also strategically aligns and coordinates rear-lot projects with other conversion projects that share the same feeder. Figure 14 shows the rear lot areas that Toronto Hydro prioritized for conversion during 2020-2024 and Table 10 provides additional details on the project areas. Rear lot areas include transformers at risk of containing PCBs and Toronto Hydro intends to eliminate all of them through the 2020-2024 projects in this segment or through the Overhead and Underground System Renewal programs by 2025.

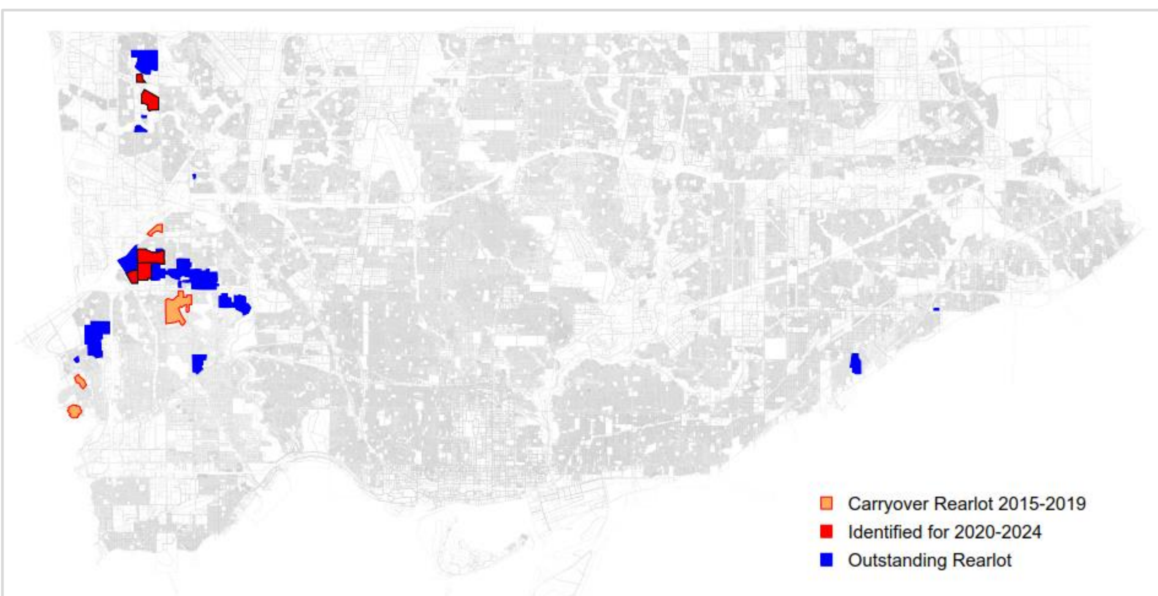


Figure 14: Outstanding Rear Lot Areas to be completed during 2020-2024 and beyond

Table 10: Planned Rear Lot Projects for 2020-2024

Rear Lot Area	Number of Customers	Expected Date of Completion	Number of Outages (2012-2017)	Number of Outages Greater than 5 Hours (2012-2017)
Thorncrest	618	Civil 2020 Electrical 2021	11	2
Jamestown	258	Civil 2021 Electrical 2022	15	12
Markland Woods	300	Civil 2021 Electrical 2022	3	0
Martin Grove Gardens	452	Civil 2022 Electrical 2023	8	4
Mount Olive	83	Civil 2022 Electrical 2023	4	4
Kingsview	173	Civil 2023 Electrical 2024	3	1
Richview Park	263	Civil 2023 Electrical 2024	6	0
Willowridge	201	Civil 2023 Electrical 2024	6	3

It should be noted that the Jamestown project, originally scheduled for 2021-2022 construction, may be advanced to an earlier year due to increasingly deteriorating assets that have led to continued lengthy outages.

E6.1.4.2 Box Construction Conversion Expenditure Plan

Toronto Hydro invested $51.9 million in Box Construction Conversion projects between 2015 and 2017, resulting in the conversion of 2,422 poles framed for safer, more reliable, and more operationally flexible 13.8 kV feeders. The utility plans to invest $68.7 million in 2018-2019 to convert another 2,900 poles. This will leave an estimated total of 3,800 to be addressed between 2020 and the 2026 target date for completion. For the 2015-2019 period, Toronto Hydro expects to spend about 17 percent ($18 million) more than the $102.9 million initially forecast for the period. The higher costs are due to the differences between high level estimates used for the forecasts and the detailed estimates and actual costs following detailed design and construction.

Toronto Hydro plans to invest $107.3 million over the 2020-2024 period to convert approximately 2,600 of the 3,800 remaining poles. The utility expects this work to improve the average outage restoration time for 22,700 downtown residential and small business customers. Other anticipated benefits of this work include reduced safety risks related to EUSR, CSA and ESA compliance issues, improved speed, and cost-efficiency of customer grid access in high-growth areas of downtown Toronto, and reduced traffic disruptions due to less frequent repairs and maintenance. This proposed spending represents a reduction of about 11 percent versus the 2015-2019 pace of investment, but will still allow Toronto Hydro to meet its objective of eliminating box construction by 2026. Figure 15 below shows the forecasted rate of Box Construction Conversion out to 2026.

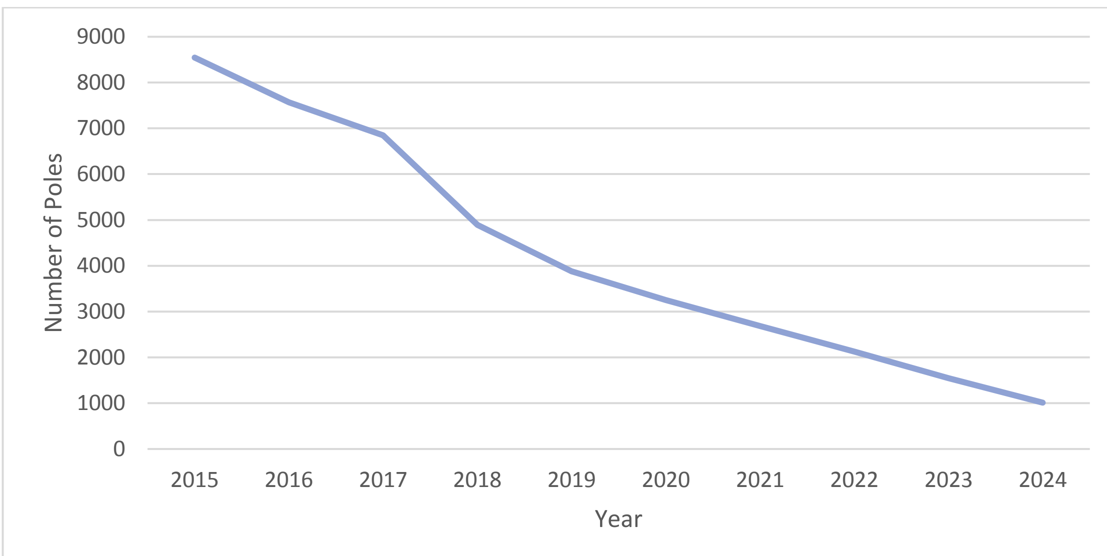


Figure 15: Rate of Conversion of Poles in the Box Construction Program (2015-2024)

Figure 16 shows the approximate location of the box construction conversion areas that Toronto Hydro has prioritized for the 2020-2024 planning horizon.

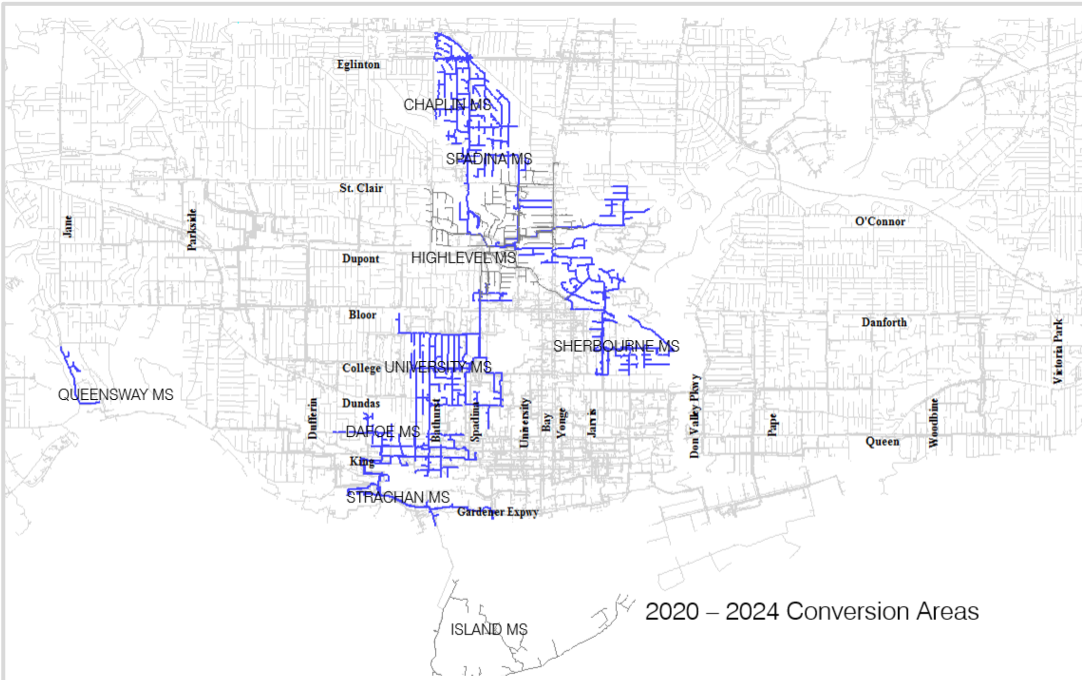


Figure 16: Map of proposed conversion for 2020-2024 (Estimated locations)

To reduce the variance between forecast and actual costs, Toronto Hydro examined a number of completed box construction feeder conversions between 2015 and 2017 to develop an average cost per conversion of a box construction pole. This analysis concluded that costs per pole will vary considerably from one project to the next.

This is driven by specific area characteristics. For example, one street may solely have overhead supply directly feeding customers on a quiet side street without trees or underground risers. Other box construction assets may be on a main downtown artery, such as Queen Street, with both primary and secondary distribution and risers going from overhead to underground and vice versa. Some areas may have heavy vegetation, road moratoriums, road access or timing work restrictions, or third-party attachments such as TTC street cars that require coordination. Further to this, for some projects, based on their location and box construction framing density, crews need to use different techniques to remove the legacy equipment safely.

Toronto Hydro used the average cost of $0.029 million per pole plus inflation and engineering and support costs to derive the forecast costs for 2020-2024. By using historical actuals to estimate costs, Toronto Hydro expects variances to be reduced in the 2020-2024 period.

When planning box construction conversion projects, Toronto Hydro considers reliability, third party scheduling conflicts and the planned decommissioning of municipal stations. For the eight stations remaining that carry box construction lines, Toronto Hydro will coordinate the elimination of box construction with the station and external dependencies listed in Table 12. To improve productivity and safety, crews will cut the top half of the box pole and take it to the yard and disassemble it on the floor with multiple crews instead of disassembling the box construction manually on the roads and sidewalks in a bucket truck.

Table 12: Remaining stations carrying box construction lines

Station	Conversion	Station-related or External Dependencies	Projected Costs ($ Millions)
Sherbourne MS	*2020 -2021*	Station Decommissioning	25.8
Queensway MS	*2020 -2021*	Station Decommissioning	
Dafoe MS	*2020-2022*	Station Decommissioning	17.8
University MS	*2022 -2023*	Station Decommissioning	20.1
Spadina MS	*2022-2023*	Metrolinx Conflict	
Strachan MS	*2023 - 2024*	Hydro One Dependency	18.7
Chaplin MS	*2024 -2025*	Metrolinx Conflict	24.9
High Level MS	*2025-2026*	Hydro One Dependency	40.5

Once the 2020-2024 plan is executed, there should be only one to two stations (i.e. High Level and Chaplain) remaining with Box construction feeders. Projected Costs above include inflation or EAR. Note: 2025-2026 High Level MS is not planned for this rate filing and should be exempted from the total spend.

E6.1.5 Options Analysis

E6.1.5.1 Options for Rear-Lot Conversion

1. **Option 1: Reactive replacement approach**

This option proposes to maintain the rear lot distribution system and repair it reactively. This option will address equipment issues as feeders fail and involves regular maintenance work to mitigate any critical risks. However, reactive replacement tends to cost more than planned replacement, will not achieve efficiencies and operational expenditure reductions related to moving to 27.6 kV voltage, and will result in deteriorated equipment remaining in residential backyards. This option does not address the safety, reliability, and access issues that are inherent to the system and is therefore not prudent.

2. Option 2: Rebuild rear lot distribution to ensure it meets current safety regulations

This option proposes to rebuild rear lot distribution to replace the aging and non-standard equipment that is currently in use. Measures should be taken to ensure that identified safety issues are addressed. This would involve installing new poles, transformers, and conductors to meet overhead requirements. For underground equipment, trenching each owner's yard for ducts and then re-sodding the yards would be required. As well, extensive tree trimming, and in some cases tree clearing, may be required in heavy vegetation areas.

This option could reduce the number of outages experienced; however, it does not address access issues and may involve potentially unsafe work environments for Toronto Hydro crew members. Furthermore, fault location and repair will remain a lengthy and difficult procedure and customers will continue to experience long outages when they occur. In addition, the minimum clearance will not be possible to achieve in certain areas of the system. In summary, while a renewal program in the rear lot will improve the equipment, it will not address the operational, safety and reliability issues that are associated with the rear lot. Many of the current issues would reoccur years later, making the benefits arising from this option temporary. Moreover, given the difficulty associated with winter construction, most of the construction would have to take place in the summer and disrupt customers' enjoyment of their backyards.

3. Option 3: Replace rear lot distribution with overhead front lot distribution

This option involves replacing the rear lot distribution system with an overhead front lot distribution system. All 4.16 kV equipment would be removed from the rear lot and customers will be supplied from a 27.6 kV feeder from the overhead front lot. Service conductors will have to be inserted in between property lines to access the meter base located at the back of the houses.

This option is not favourable to customers as it harms the aesthetic value of the front lots in their neighbourhoods. Also, in many areas, large and mature trees would need to be cut down to accommodate a pole line running along the street. This will be opposed by the City's Urban Forestry Department, which has a mandate to grow the tree canopy in Toronto. Furthermore, because communication lines are typically supplied through the rear, there will be an abundance of overhead lines in the neighbourhoods. Customers and local stakeholders have previously expressed concern about the effect this would have on their neighbourhood and their property values. Likely complaints arising in this regard could trigger project postponement or redesign, ultimately increasing the cost and duration of the projects.

4. Option 4 (Selected Option): Replace rear lot distribution with underground front lot distribution at proposed pace

Under this option, the rear lot distribution would be removed and the customers would be supplied by a 27.6 kV front lot underground service. Service cables would be supplied underground between the customers' properties and connect to the meter base located at the back of the house. This would maintain the aesthetics of the customer's front lot and neighbourhood.

Underground front lot distribution is preferred because it mitigates accessibility and safety issues and addresses aging and non-standard equipment that could reduce reliability and exacerbate other issues. Furthermore, it improves reliability by moving the equipment underground in heavily treed areas. This will reduce faults associated with tree and animal contacts and weather-related outages.

Option 4 is the chosen alternative; as it aligns with current standard design practices and increases the safety and reliability of the system. It also reduces the time and effort required to respond to power outages in the area and maintains neighbourhood aesthetics, thereby maximizing customer value derived from the necessary conversion projects. This option provides short- and long-term benefits to customers and Toronto Hydro.

5. Option 5: Replace rear lot distribution with underground front lot distribution at accelerated pace

At an accelerated pace, Toronto Hydro could eliminate all rear lot plant by the end of 2024. This option would provide the same benefits as Option 4 but for all rear lot areas. Reliability would improve faster and Toronto Hydro crews and the public would be exposed to the safety risks associated with rear lot supply over a shorter period and less spending would be required to replace failed rear lot assets on a reactive basis. However, the aggressive pacing would likely stretch resource requirements and pose scheduling challenges as civil work is usually limited to non-winter months. In addition, Toronto Hydro estimated that the required annual funding would be more than twice that for the recommended plan.

E6.1.5.2 Options for Box Construction Conversion

1. Option 1: Reactive replacement approach

In the status quo scenario, Toronto Hydro would continue to maintain and repair box construction assets and replace failed assets as needed. Due to the high number of box construction assets past their useful lives, Toronto Hydro anticipates that maintaining the status quo would result in additional maintenance costs and deteriorating reliability which are otherwise avoidable. The safety risks and operational issues would remain or worsen.

Option 1 would likely also have the disadvantage of forcing Toronto Hydro to continue investing in and maintaining stations assets at the 4 kV municipal stations that supply existing box construction feeders. Many of these stations are lightly loaded and avoided costs could be realized by decommissioning the stations following load conversion as part of the Box Construction segment.

2. Option 2 (Selected Option): Convert from Box Construction to new armless overhead infrastructure at proposed pace

Converting and renewing the box construction to a standardized system for which replacement components are more readily available would improve safety for the public and Toronto Hydro crews (i.e. by enabling the minimum required clearances). It would also provide capacity to accommodate future load requests, address the risk failure of assets, and reduce outage durations. At the proposed pace Toronto Hydro would be on track to meet its goal of eliminating all box construction by the end of 2026.

Option 2 is the chosen alternative as it provides the most cost effective option to increase the safety and reliability of the system. At the same time, it reduces the time and effort required to respond to power outages in the downtown area, thereby maximizing customer value derived from the necessary conversion projects. This option provides short and long term benefits to the customer and Toronto Hydro.

3. Option 3: Convert from Box Construction to new armless overhead infrastructure at accelerated pace

At an accelerated pace Toronto Hydro could eliminate all box construction by the end of 2023. This option would provide the same benefits as Option 2 but those benefits would be realized earlier in some areas. However, the expedited pace may not be possible due to resource limitations and station and external dependencies (i.e. Table 12 in Expenditure Plan section) restricting when projects can be executed. In addition, Toronto Hydro estimated that the accelerated rate would cost approximately 50 percent more than the Option 2 plan.

E6.1.6 Execution Risks & Mitigation

E6.1.6.1 Rear-Lot Conversion

Timely third-party project coordination: One program risk is the potential for a minimum five-year moratorium on new road work in areas where Toronto Hydro intends to do rear lot conversion work. Toronto Hydro will mitigate this risk by working closely with the City of Toronto on planned road work (i.e. through utility coordination council meetings). In the event that planned City of Toronto work puts program completion at risk, Toronto Hydro will negotiate with the city to coordinate a construction schedule that is acceptable to all parties and stakeholders involved.

Customer Engagement: Customer care is a significant aspect of risk mitigation during the planning and execution phases of rear lot conversion, which by nature are relatively intrusive and involve construction on multiple sides of each customer property. To determine asset locations that best align to customer preferences, Toronto Hydro maintains extensive and proactive customer communication and provides an opportunity for customers to voice their concerns and to work with the designer and constructor. In most cases, community meetings are held to proactively introduce residents to the project plans and educate them on construction implementation. City Ward councillors are informed of the project and often are invited to community meetings and pre-construction meetings to assist with constituent inquiries. Written letters are sent in advance to customers' homes to inform them of the project, new equipment installations and line of sight to new equipment as per applicable municipal notice requirements.

Conversion coordination: The remaining rear lot configurations feature multiple feeders that provide service across the same easement, making conversion activities relatively complex. These feeders depend on one another for load transfers, especially during contingency scenarios (i.e. during outages on any of the feeders). Feeders tie with one another and can be used to resupply each other if a feeder's primary source of power from a substation is disrupted due to a fault or work being done. Therefore, it is important that alternative sources of power remain available during conversion in the event of an emergency. These interconnections require careful staging of conversion jobs over several years.

E6.1.6.2 Box Construction Conversion

Timely third-party project completion*:*

- **Hydro One:** Toronto Hydro works with Hydro One to schedule preparation and upgrade of stations for conversion. If such preparatory work is not completed on time, it may delay full conversion of the respective feeders. Mitigation through close coordination and communication is key for project execution.
- **Customer Coordination:** For most commercial customers serviced on the 4.16 kV system, there is underground equipment, risers and terminations that are on the pole and supply the customer underground. Transferring a riser and termination requires an outage to the customer to conduct the work safely. Coordinating power interruptions and access with the customer may delay the project and Toronto Hydro seeks to mitigate this risk through proactive and early customer engagement.
- **Construction Coordination:** Many of the remaining box construction assets are within high pedestrian and vehicle traffic areas which also include TTC bus or streetcar routes (see example shown in Figure 17). In this regard, mitigation involves proactive coordination and engagement with the City to create a traffic plan, especially at major intersections. Most pole installations require a single lane to be occupied by trucks and equipment and as such, inadequate coordination would jeopardize project completion in a timely manner.

Figure 17: Area with High Pedestrian and Vehicle Traffic, including TTC Routes.

Third-Party assets attached on Toronto Hydro's assets: Third-party assets attached to utility poles, such as Rogers, Bell, and City assets, can interfere with full conversion and pole removal. Toronto Hydro will engage owners of these assets as soon as possible to coordinate and plan their transfer. Identifying locations that require civil work will enable it to be done prior to pole line installation, so that the start of project work is not delayed.

E6.2 Underground System Renewal – Horseshoe

E6.2.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 420.7	**2020-2024 Cost ($M):** 460.3
Segments: Underground System Renewal Horseshoe	
Trigger Driver: Failure Risk	
Outcomes: Customer Service, Reliability, Environment	

The Underground System Renewal – Horseshoe program ("the Program") addresses major underground distribution assets serving primarily low voltage customers in the Horseshoe area of Toronto. The Program invests in proactive asset renewal to mitigate reliability, safety, and environmental risks, and is a continuation of the activities described in the Underground Circuit Renewal program in Toronto Hydro's 2015-2019 Distribution System Plan.[1]

The Program addresses three major underground asset classes: cables, transformers, and switches. Usage, aging, and exposure to harsh environments cause these assets to deteriorate over time, increasing the risk of failure. Legacy asset design issues further increase the probability of failure for certain asset types addressed by the Program.

Outages caused by asset failure on the underground system take approximately 35 percent longer to restore than outages on the overhead system, and can result in lengthy interruptions lasting as long as 24 hours. The failure characteristics of legacy underground cables are such that customers can experience multiple cable-related outages in a short period, leading to potentially significant declines in customer satisfaction in affected neighbourhoods.

The Program's investments in the three major underground asset classes are summarized as follows:

- **Cables**: Cables are the single greatest contributor to outages caused by defective equipment on Toronto Hydro's system, resulting on average in 140,000 customer hours of interruption annually. Through prioritized neighbourhood rebuild projects, focused on replacement of high-risk direct-buried cross-linked polyethylene ("XLPE") cables, Toronto Hydro has had success in reducing the number of customer interruptions due to cable failure from over

[1] EB-2014-0116, Exhibit 2B, Section E6.1

280,000 per year in 2007 to under 140,000 in 2017. There are currently 809 circuit-kilometres of direct-buried cable and direct-buried cable in duct in the underground system, of which 368 circuit-kilometres are direct-buried XLPE cable, i.e. the subset of cable installations with the highest failure risk. Toronto Hydro expects this asset population to be a significant source of failure risk and driver of reliability outcomes as the cables continue to age over the 2020-2024 period. Approximately 70 percent of this cable has reached or passed its useful life as of 2017. Without investment an estimated 90 percent will be at or beyond useful life by 2024. Toronto Hydro is planning to replace an estimated 215 circuit-kilometres of the highest risk direct-buried XLPE cable during the 2020-2024 period to maintain current average reliability performance on the underground system and to sustain improvements in the number of feeders experiencing seven or more interruptions per year ("FESI-7").

- **Transformers:** Underground transformers are typically exposed to harsh environmental conditions. Defective transformers cause approximately 20,000 hours of customer interruption annually and contribute to 26 percent of failures on the underground system. As of 2017, 19 percent of the transformers in Toronto Hydro's underground distribution system have reached or surpassed useful life, and over 1,000 units exhibit at least moderate deterioration. Without proactive investment, Toronto Hydro expects the proportion of underground transformers past useful life to increase by over 50 percent to 29 percent in 2024, and the number of units with at least moderate deterioration to increase to over 3,500. Generally, Toronto Hydro replaces aging and deteriorated underground transformers proactively as part of its direct-buried cable rebuild projects, and will continue to do so in the 2020-2024 period. To support the utility's objective of reducing the number of potentially high-consequence PCB leaks, Toronto Hydro plans to prioritize the replacement of underground transformers that are at risk of failure are known to contain, or are at risk of containing, PCB-contaminated oil. Overall, the utility plans to replace an estimated 1,900 underground transformers during the 2020-2024 period through a combination of area rebuilds and PCB-targeted spot replacement, with the objective of maintaining average system reliability and continuously reducing the risk of PCB leaks.
- **Switches**: Underground switches are continuously exposed to harsh environmental conditions, and their failure typically leads to prolonged outages, ranging from three hours up to 17 hours and affecting an average of 1,300 customers at a time. On average, switches have contributed to approximately 20,000 hours of customer interruption annually. Failure

of these assets can also pose employee and public safety risks due to the potential for arc flashing, a risk that is higher with Toronto Hydro's remaining population of legacy air-insulated switches. The number of air-insulated switches in end-of-serviceable life condition ("HI5") is anticipated to rise from about 40 to over 130 by 2024, which aligns with the accelerated rate of degradation that Toronto Hydro has seen for this type of switch in the field. (Over 40 percent of the failed switches that the utility analyzed in the last five years failed prior to reaching their expected useful life of 30 years, with the highest rate of failure occurring in the 15-24 years range.) Over 700 switches are currently operating beyond useful life. During the 2020-2024 period, the utility plans to proactively replace an estimated 230 underground switches in conjunction with area rebuild projects, prioritizing higher-risk air-insulated switches operating beyond useful life and/or exhibiting material degradation.

Toronto Hydro plans to invest $460 million in the Underground System Renewal program in 2020-2024, which is a 9.5 percent increase over projected 2015-2019 spending in this Program (including forecasted inflation). This pace of investment is necessary to maintain current average reliability on the underground system, sustain improvements in the number of feeders experiencing seven or more interruptions a year, continuously reduce the risk of PCB-contaminated oil leaks into the environment, and prevent asset-related risk on the underground system from increasing in an unsustainable manner over the long-term.

E6.2.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's objectives and obligations to connect low and high voltage customers within 5 and 10 business days respectively at least 90 percent of the time (pursuant to the OEB's new connection metrics and section 7.2 of the Distribution System Code ("DSC"), by upgrading 34 circuit kilometres of low capacity 4.16 kV or 13.8 kV distribution lines to higher voltage capacity of 27.6 kV distribution lines.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, Direct Buried Cable replacement measure) by o Replacing approximately 215 circuit-kilometres of direct buried underground cable that poses elevated risks to reliability; and o Replacing assets at and beyond useful life or showing signs of at least material deterioration (i.e. HI4 and HI5).

Environment	• Contributes to improving Toronto Hydro's Spills of Oil Containing PCBs measure, and reducing the environmental impact and risks associated with Toronto Hydro's distribution system by removing underground assets at or beyond useful life that contain or are at risk of containing PCBs by 2024, pursuant to PCB regulations (the *Canadian Environmental Protection Act*, SOR/2008-273, the *Ontario Environmental Protection Act* and the Toronto Municipal Code, Chapter 681 Sewers)

E6.2.3 Drivers and Need

Table 3: Drivers and Need

Trigger Driver	Failure Risk
Secondary Driver(s)	Environmental Risk, Safety

The Underground System Renewal program focuses on replacing three types of assets: cables, transformers, and switches. These assets are primary components of the underground distribution system and will be replaced, generally on a like-for-like basis, in accordance with current standards.

The proposed renewal is driven by the risk and impact of underground distribution asset failures on system reliability, the environment, and public and employee safety. These risks stem from two primary factors. The first is accelerated degradation of asset condition due to exposure to external elements, including dirt, salt, dust, moisture, and humidity. This contributes to a loss in the integrity of the physical asset installed in the field which can in turn lead to failure. Secondly, assets that are at, or approaching their useful life, are subject to an elevated probability of failure. Table 4 set outs the useful life of the underground assets in the Horseshoe area. Asset failures give rise to: (1) reliability risks, which can cause outages and directly impact customers; (2) environmental risks, caused by oil spills (potentially containing PCBs) into the environment; and (3) safety risks, from arcing, and catastrophic failures.

Table 4: Useful Life of Underground Assets by Type in the Horseshoe

Type		Useful Life (Years)
Direct Buried Cable	*Jacketed*	40
	Un-jacketed	23
Cable in concrete encased duct (Jacketed/Un-jacketed)		50
Transformers	*Submersible*	33
	Padmounted	35
	Building Vault	
Switches	*Padmounted*	30
	Vault	40

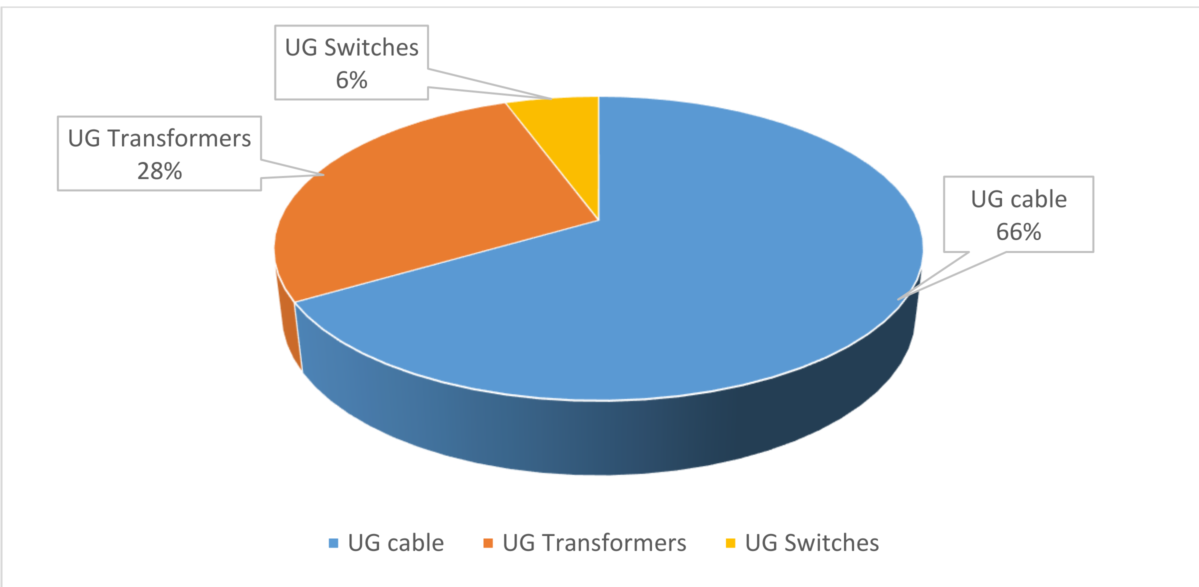


Figure 1: Underground Equipment Failure Rate by Asset Type from 2007 to 2017

Historical investments in the Underground System Renewal program have resulted in improved reliability as illustrated in Figure 2 below. The total number of outages related to underground equipment failures decreased steadily over the last ten years, by an average of 5 percent per year.

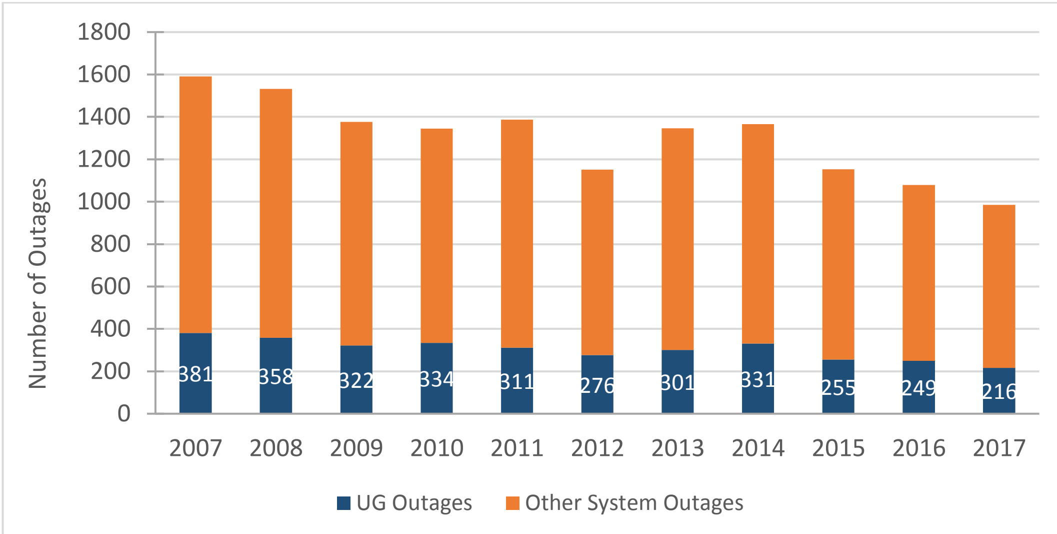


Figure 2: Ten-year Trend of Underground Horseshoe System Contribution to Overall System Outages

These investments have reduced the total number of customers interrupted due to underground equipment failures over the past ten years. Toronto Hydro has been able to sustain the improved numbers, largely keeping them stable over the past five years, as seen in Figure 3.

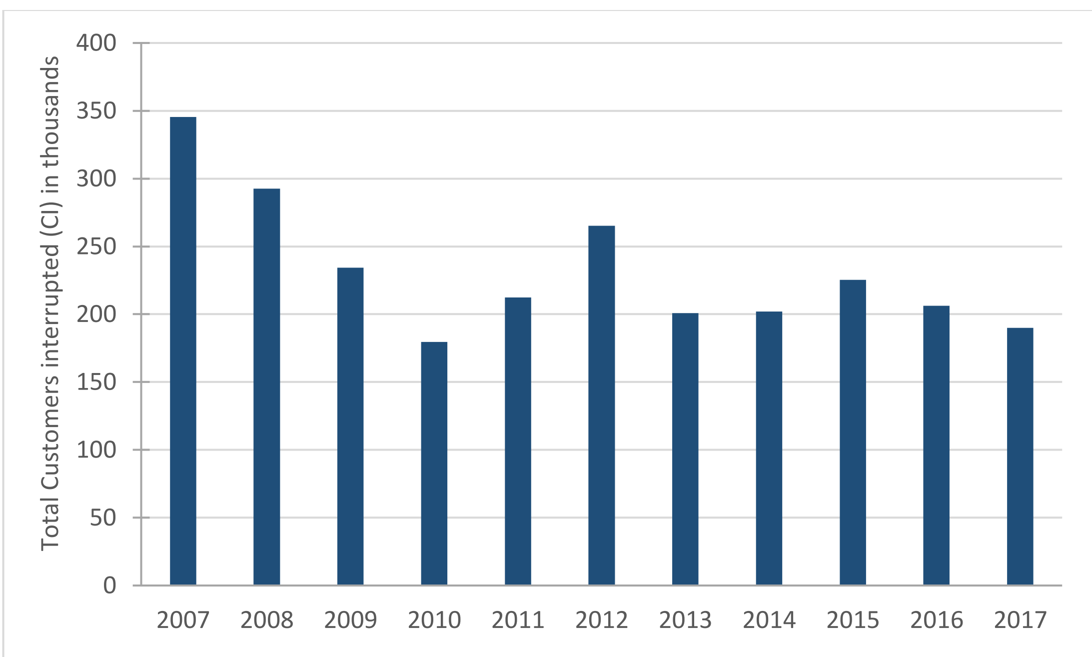


Figure 3: Ten-Year Trend of Customers Interrupted due to Underground Equipment Failure

While historic investments have improved underground reliability in the Horseshoe area, asset demographics are such that Toronto Hydro must maintain the pace of renewal to sustain these improvements. A significant number of assets (e.g. cables) are already past their useful life as of 2017 and the population continues to age. This increases the risk of failure, requiring Toronto Hydro to reactively replace faulted underground equipment. In general, underground assets are more difficult to replace compared to those in the overhead system mainly because they are installed below-grade and not readily visible or accessible for fault locating.

When an underground fault occurs, controllers first check SCADA devices to identify what section of the feeder has faulted. Crews then rely on fault indicators installed on various points on a feeder to find the component that has faulted. This process can take up to hours as crews may have to open every submersible transformer to check for indications of the fault.

Fault locating of direct buried cable is particularly challenging, as crews first need to perform testing that identifies the general location of a fault, then dig up the identified location to confirm and pinpoint the actual cable fault. In certain cases, crews need to dig a number of pits in order to identify the exact location of the fault before repairs can be made. The time required to locate the fault has negative impacts on customers as it can lengthen the outage duration for those customers. Operational outages to repair these assets can also expand the outage to surrounding areas thus affecting more customers.

Additionally, the disruptive nature of the work leads to significant unplanned disruptions and inconveniences for the neighbourhood and community as a whole, and often requires last minute coordination with third parties under emergency situations and tight timelines. For underground assets, this is particularly difficult where customers own the assets (such as vaults), as coordination can delay the repair work and extend the outage. In contrast, proactive replacement allows Toronto Hydro to coordinate work with third parties well ahead of the scheduled repair work.

The Underground System Renewal program is also driven by the need to mitigate the risk of negative environmental impacts from asset failure. Older assets such as transformers are at risk of having insulating oil containing PCBs. This is of concern with respect to underground transformers (padmount, vault, and submersibles) as their surrounding areas are directly connected to the municipal system through drains. Toronto Hydro needs to proactively replace these assets to comply with PCB regulations.

E6.2.3.1 Replacement of Underground Cable

Toronto Hydro plans to replace high risk direct buried cable that causes poor reliability in the Horseshoe area.

Generally, two types of cables exist in the Horseshoe underground distribution system: (i) XLPE; and (ii) tree-retardant cross-linked polyethylene ("TRXLPE"). These can be installed in three ways: (i) direct buried cables; (ii) direct buried ducts; or (iii) concrete encased ducts. Direct buried XLPE cables in Toronto Hydro's system were installed before 1990 and were fabricated using manufacturing processes that are now considered inferior. These assets are a legacy type of construction where cables are laid directly in underground trenches without a protective barrier.

These cables are susceptible to outages due to direct exposure to environmental conditions. Moisture is the most destructive element that affects direct buried XLPE cable. Water ingress into the cable insulation in the presence of an electrical field causes microscopic tears called "water treeing". Overtime, continued moisture penetration and the presence of electrical stresses causes these water trees to become electrical trees (whereby the tears become carbonized and can conduct electricity). This causes the cable to internally short circuit and fail.[2]

Figure 4 shows the current age distribution of direct buried XLPE cable and what it will be in 2024 without investment. As of 2017, the majority (74 percent) of the direct buried XLPE cable in Toronto Hydro's distribution system is at or beyond useful life. There is also a number of circuit-kilometres that are approaching their useful life (i.e. 23 years). Without any replacement, the length of cable at or beyond useful life will reach 333 circuit-kilometres by 2024, which represents 90 percent of direct buried XLPE cable in Toronto Hydro's underground Horseshoe distribution system. An increased percentage of direct buried XLPE cable at or beyond useful life will heighten the risk of cable failure and negate the reliability improvements achieved in recent years.

[2] see Exhibit 2B, Section D2 for more details

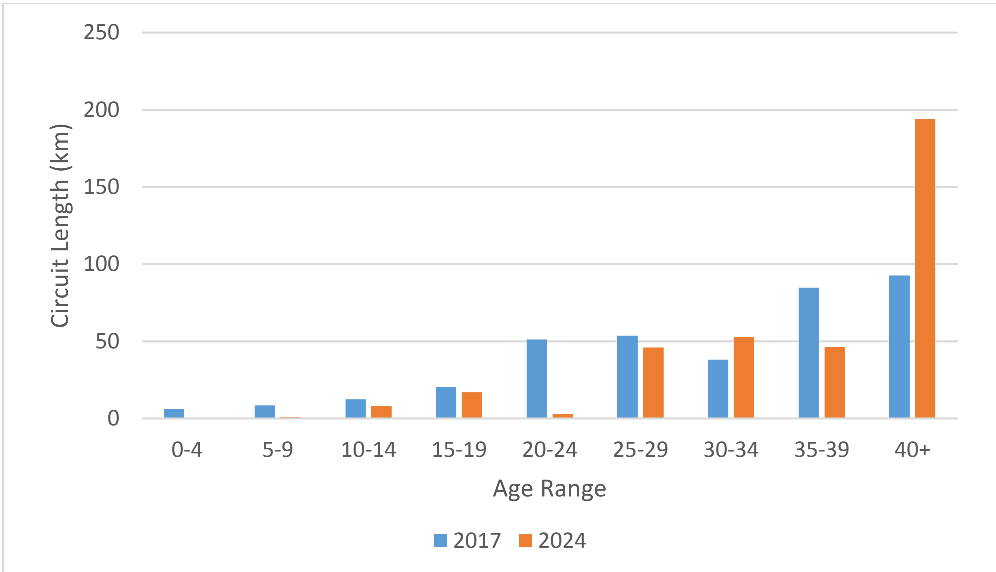


Figure 4: Direct Buried XLPE Cable Age Demographic as of 2017 and by 2024 (without Investment)

Toronto Hydro analyzed over 660 cable failures in the system between 2012 and 2016. The results show that the failure rate of all XLPE cable is significantly higher than TRXLPE cable (499 versus 169 outages). They also show that the rate of failure of XLPE increases with age. These failures can cause customer outages ranging from 4 to 24 hours and affecting an average of 800 customers.

Based on Toronto Hydro's experience with direct buried cables, following an initial failure (which is typically a sign of deteriorated insulation and electrical and thermal stresses along the entire segment), subsequent failures in the cable segment occur with greater frequency. Additionally, voltage stress applied to the cable during the fault locating process further degrades the cable insulation. The following two cases, from 2017, are illustrative of this observed pattern:

1) The residential and non-residential customers in the area of Yonge Street and Hendon Avenue in North York are supplied by a #1/0 solid 28 kV XLPE direct buried cable installed in 1975. Between June and August 2017, there were five cable failures in the same segment as shown in Table 5. As a result, the cable segment was irreparable and a reactive scope of work was issued to replace it with cable in concrete encased ducts.
   Between the time when the scope of work was issued and when the work was fully designed and executed, the area was supplied by a temporary source with no backup thus leaving customers vulnerable to additional and extended outages.

Table 5: Direct buried cable failure Incidents 2017 - Hendon

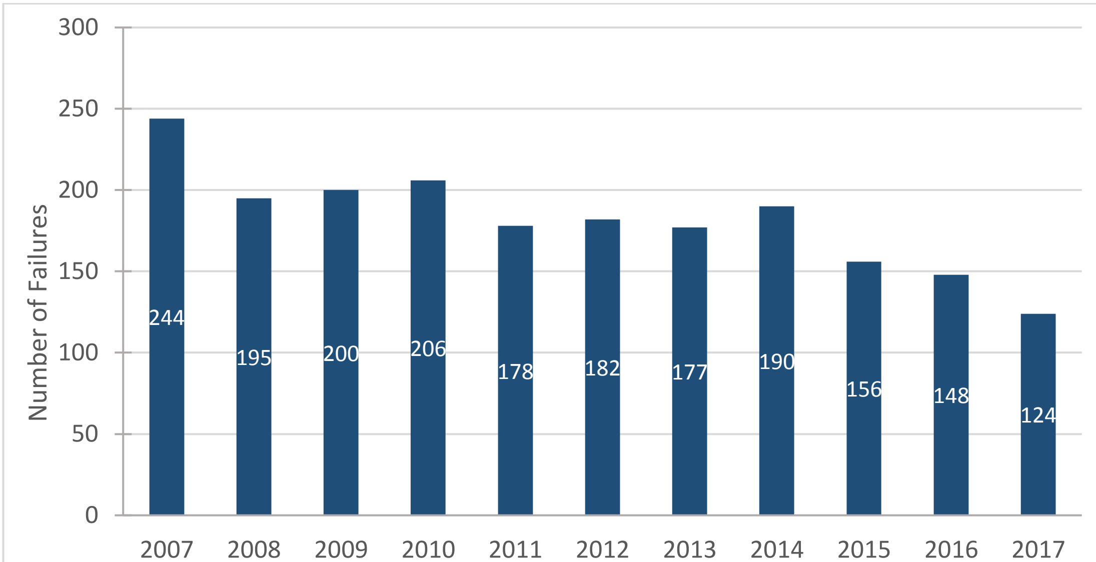
Date	Outage Duration (min)	Total Customers Interrupted (CI)	Total Customers Minutes Out (CMO)
18-Jun-2017	635	190	42600
19-Jun-2017	27	21	567
19-Jun-2017	128	88	6044
22-Jul-2017	245	88	12980
01-Aug-2017	31	28	630

2) Non-residential customers (i.e. a school and a small commercial plaza) in the area of Cliffwood Road and Don Mills Road in North York are supplied by a #1 solid 28 kV XLPE direct buried cable installed in 1975. Between September and October 2017, three cable failures occurred in the same cable segment, as shown in Table 6. The cable segment continued to fail following the first repair and was deemed irreparable and a reactive scope of work was issued to replace cable in concrete encased ducts.

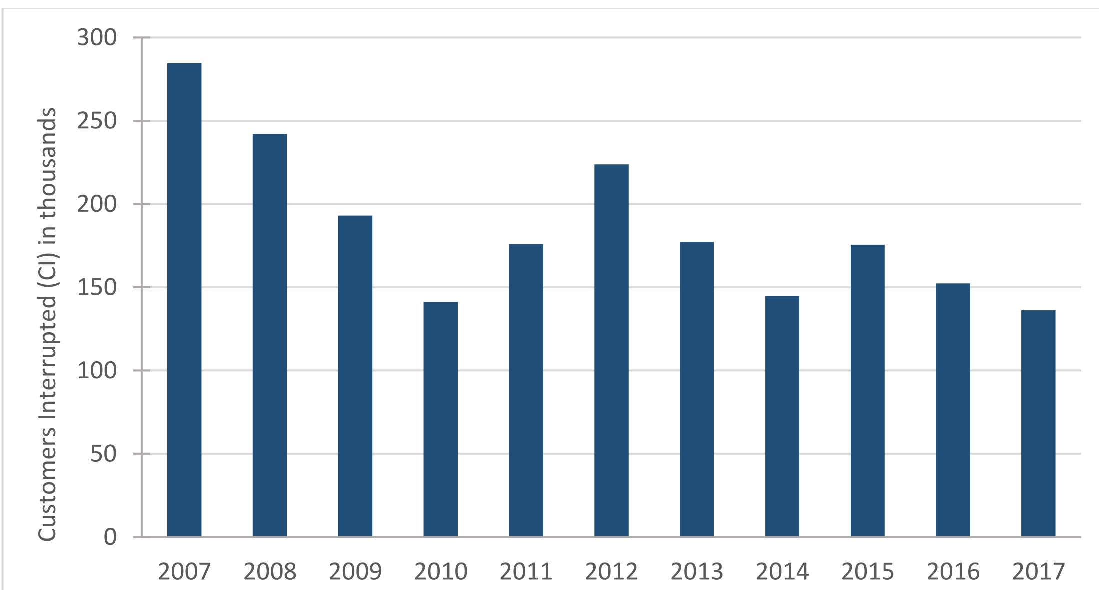
Table 6: Direct buried cable failures 2017 - Cliffwood

Date	Outage Duration (min)	Total Customers Interrupted (CI)	Total Customers Minutes Out (CMO)
10-Sep-2017	2915	1	2915
02-Oct-2017	1528	1	1528
05-Oct-2017	719	1	719

Underground cable failures account for approximately 70 percent of the underground outages in the Horseshoe system. A snapshot of the ten-year reliability of the underground cables discussed in this Program is shown in Figure 5, Figure 6 and Figure 7. Proactive underground renewal carried out through Toronto Hydro's Underground System Renewal program has improved the system reliability, reducing the number of failures from approximately 200 in the 2008-2010 period to approximately 140 in the 2015-2017 period. Despite this overall trend of decreasing failures over the past 10 years, the number of customer interruption and the hours of customer interruption has decreased at a lesser rate in recent years.



1 **Figure 5: Ten-Year Trend of Outages due to Underground Cable Failure**



2 **Figure 6: Ten-Year Trend of Total Customers Interrupted (CI) due to Underground Cable Failures**

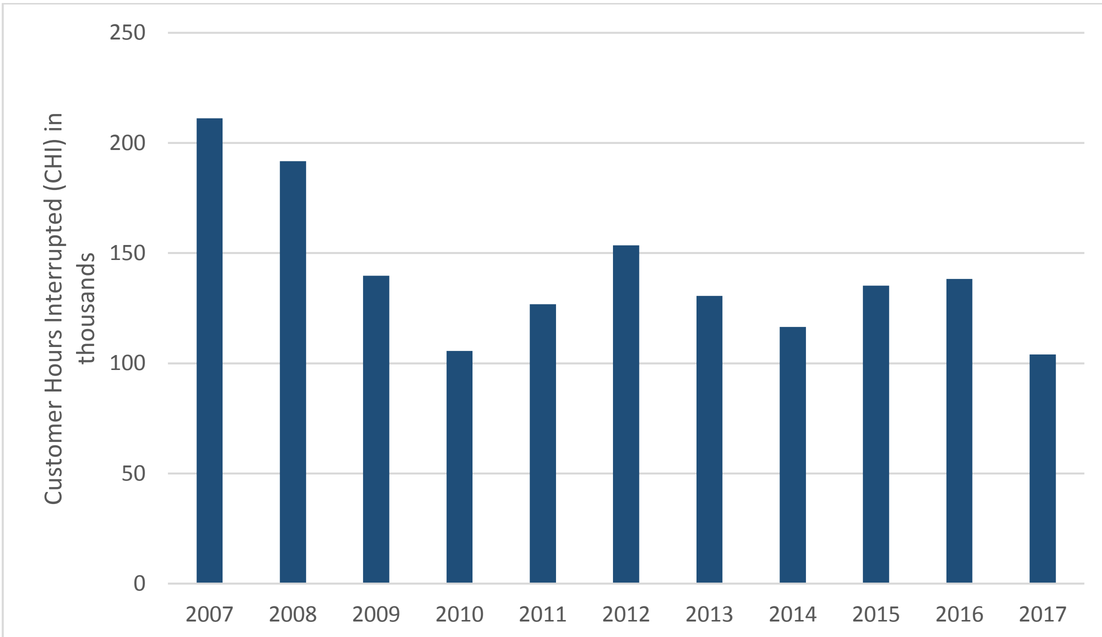


Figure 7: Ten-Year Trend of Total Customer Hours Interrupted (CHI) due to Underground Cable Failures

Of the 809 circuit kilometres of direct buried in cable in Toronto Hydro's system, the utility plans to replace approximately 215 circuit kilometres through underground rebuild projects during the 2020-2024 period. This plan is primarily driven by failure risks associated with these deteriorating and legacy (i.e. direct buried cable) assets.

Toronto Hydro's will install new TRXLPE cable in concrete-encased ducts as opposed to burying cable directly into the soil. This approach increases public safety (e.g. protects the cable from dig-ins) and reliability (e.g. greatly reduces the time it takes to replace faulted cables as new cables can be pulled into existing ducts, eliminating the need to dig out direct buried cables for repairs).

E6.2.3.2 Replacement of Underground Transformers

Toronto Hydro plans to replace transformers that are at risk of failing and pose an environmental risk due to oil leaks that may contain PCBs. Currently, there are 18,254 underground transformers in Toronto Hydro's Horseshoe distribution system.

Underground transformers are key assets used to step-down voltage and supply customers with electricity from underground cables. Three main types of underground transformers are in service:

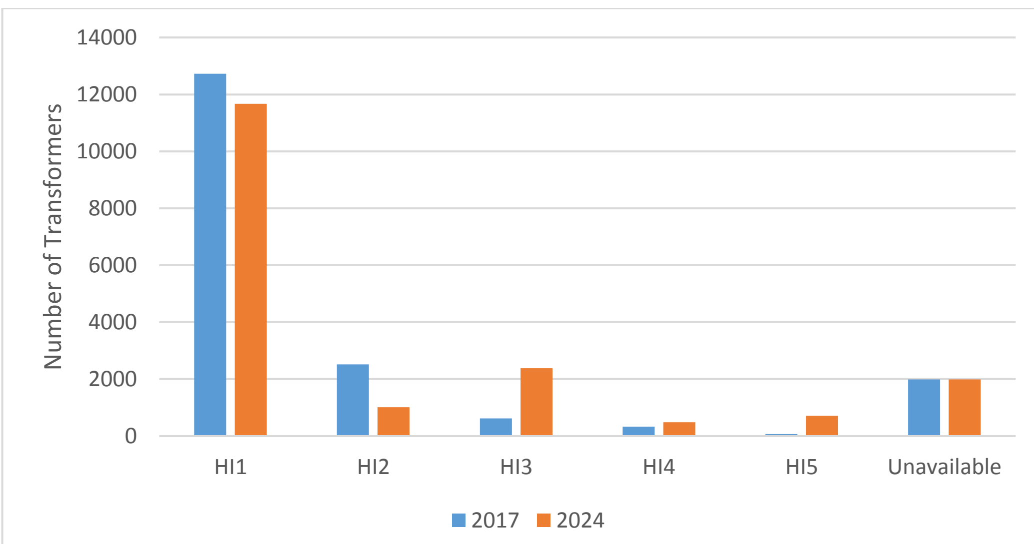
(i) submersible; (ii) padmounted; and (iii) building vault. Toronto Hydro owns approximately 8,500 submersible, 6,000 padmount, and 3,900 vault transformers. Submersible transformers are found below-grade in small structures (i.e. vaults), on public road allowances or private properties. Padmounted transformers are metal-clad enclosures with lockable cabinet doors located on top of concrete pads within road allowances or on private properties. Vault transformers are located in civil structures above-grade and, similar to padmounted transformers supply residential areas or commercial buildings.

Exposure to harsh environments causes deterioration on these transformers. Moisture is the single most destructive element (e.g. groundwater, moisture ingress), which can cause the enclosures to corrode. Precipitation and humidity over time cause corrosion (tank perforation) which can lead to oil leakage into the environment. The secondary effect of oil leakage is a reduction of transformer oil levels which causes the paper insulation to dry up, and, together with the heat created within the unit due to loading, will result in arcing and potentially catastrophic failure of the unit. As these transformers are located next to sidewalks and on private properties, such failures present significant risks to the public, and Toronto Hydro employees. An example is an incident that occurred due to premature failure of a submersible transformer with a corroded base, causing the insulating oil to slowly leak and diminishing the cooling and insulating properties of the transformer. This led to arcing and increased pressure inside the tank, causing the lid to blow off. This resulted in 3,857 customers interrupted and 1,118 customer hours of interruption.

As of the end of 2017, 400 transformers exhibit at least material deterioration (i.e. HI4 and HI5) as shown in Table 7 below. Without any capital investment, this number is expected to triple to 1,203 by the end of 2024. Not investing in asset renewal will increase reliability risks on the distribution system and run the risk of negative environmental impacts from asset failure as the transformers continue to deteriorate. The asset condition profiles of the transformers as of 2017 and in 2024 (forecasted) without investment can be seen in Figure 8.

1 **Table 7: Asset Condition Assessment for Underground Transformers in 2017 and 2024 without**
2 **Investment**

Condition	UG TX - Padmounted		UG TX - Submersible		UG TX - Vault		Total 2017	Total 2024
	2017	2024	2017	2024	2017	2024		
HI1 - New or Good Condition	4474	4153	6272	5986	1975	1528	**12721**	**11667**
HI2 – Minor Deterioration	603	296	534	280	1385	437	**2522**	**1013**
HI3 – Moderate Deterioration	246	555	232	501	143	1325	**621**	**2381**
HI4 – Material Deterioration	88	205	168	121	74	163	**330**	**489**
HI5 – End-of-Serviceable Life	16	218	42	360	12	136	**70**	**714**
Unavailable	493	493	1198	1198	299	299	**1990**	**1990**
Grand Total	**5920**	**5920**	**8446**	**8446**	**3888**	**3888**	**18254**	**18254**



3 **Figure 8: Underground Transformers ACA as of 2017 and in 2024 without Investment**

4 A summary of the 10-year reliability of the underground transformers is shown in Figure 9, Figure 10
5 and Figure 11. As seen in Figure 9, there has been an overall reduction in the number of system
6 outages (e.g. an average of 99 per year between 2007 and 2009, down to an average of 67 per year

between 2015 and 2017). Without investment, Toronto Hydro expects the reliability improvements made in recent years to be eroded and eventually reversed.

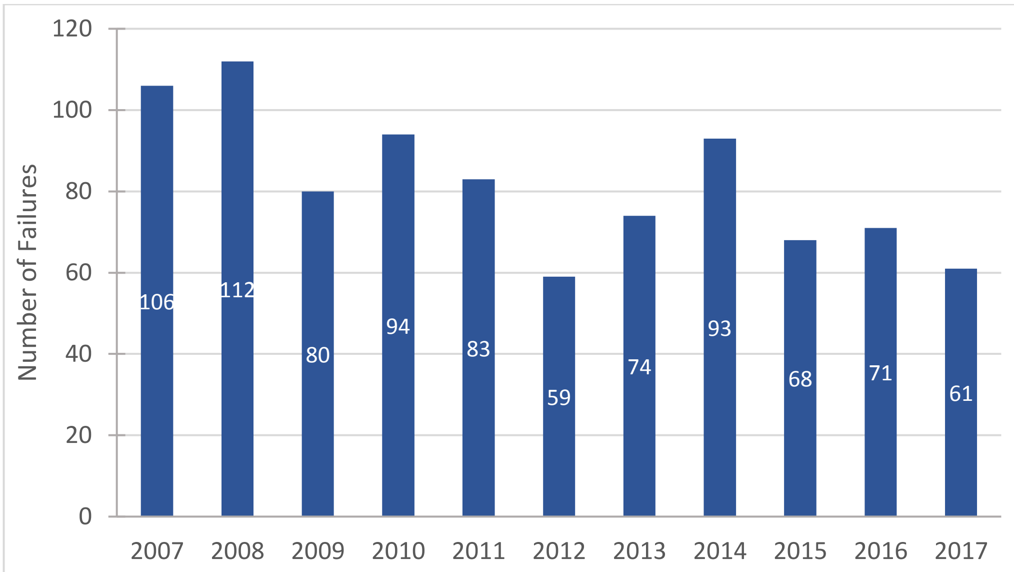


Figure 9: Ten-Year trend of outages due to underground transformer failures

However, despite an overall reduction in the total number of failures, the number of customers interrupted has increased from 2015 to 2017. Over the last two years, customer interruptions resulting from padmounted and submersible transformers failures have risen considerably, as shown in Figure 10. These failures cause outages with durations ranging from 2 to 24 hours and can affect an average of 480 customers.

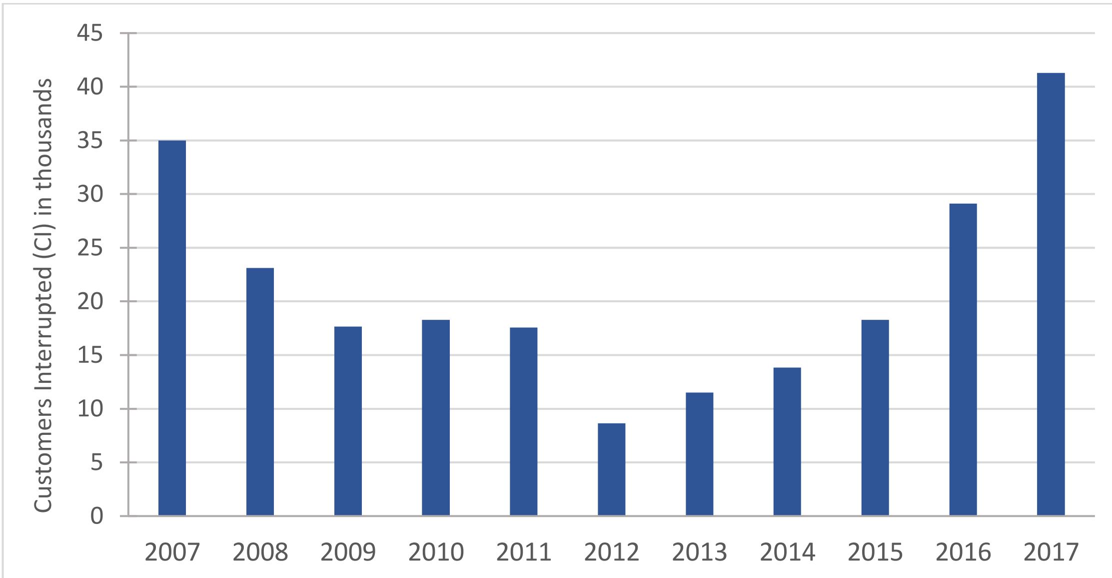


Figure 10: Ten-Year Trend of Total Customers Interrupted (CI) due to Underground Transformer Failures

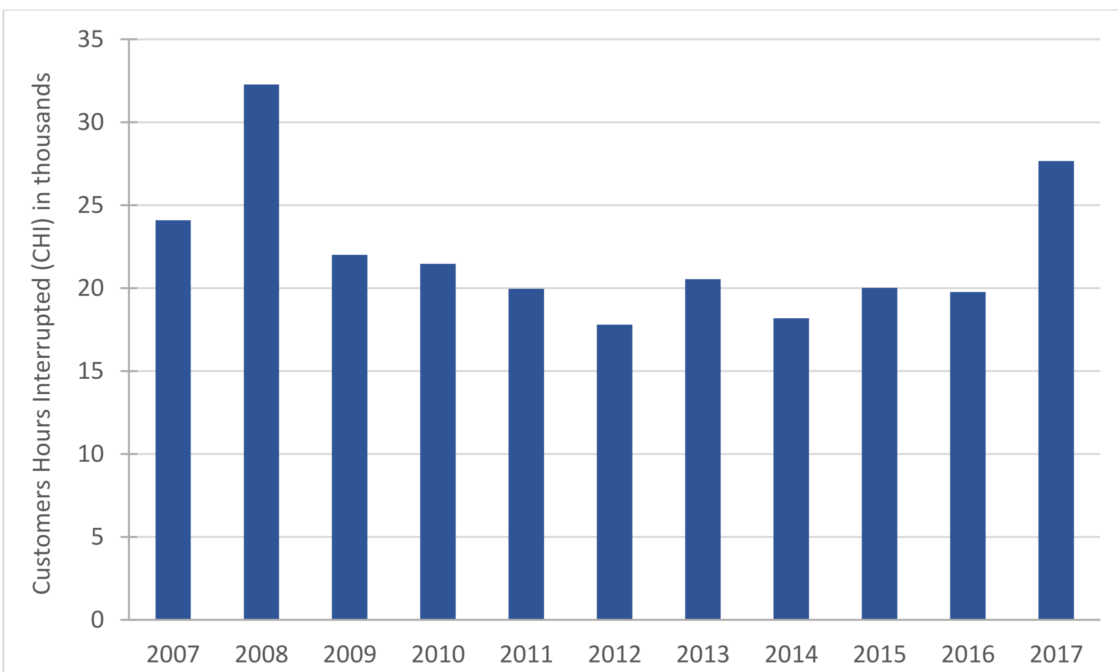


Figure 11: Ten-Year Trend of Customer Hours Interrupted (CHI) due to Underground Transformer Failures

The failure risk of these assets is mitigated through the Preventative and Predictive Underground Line Maintenance program;[3] however, environmental conditions can accelerate the deterioration and failure of these assets prior to their next inspection due to the nature of their surroundings.

Toronto Hydro investigated 257 underground transformers failures that occurred between 2012 and 2017. The results of this analysis (see Figure 12 and Figure 13) show that 35 percent[4] of the failed underground transformers failed at or beyond useful life and that the number of failed units increases with transformer age. Therefore, if not proactively replaced, transformers on Toronto Hydro's distribution system which are at or beyond their useful life of 33 or 35 years are at an increased risk of failing.

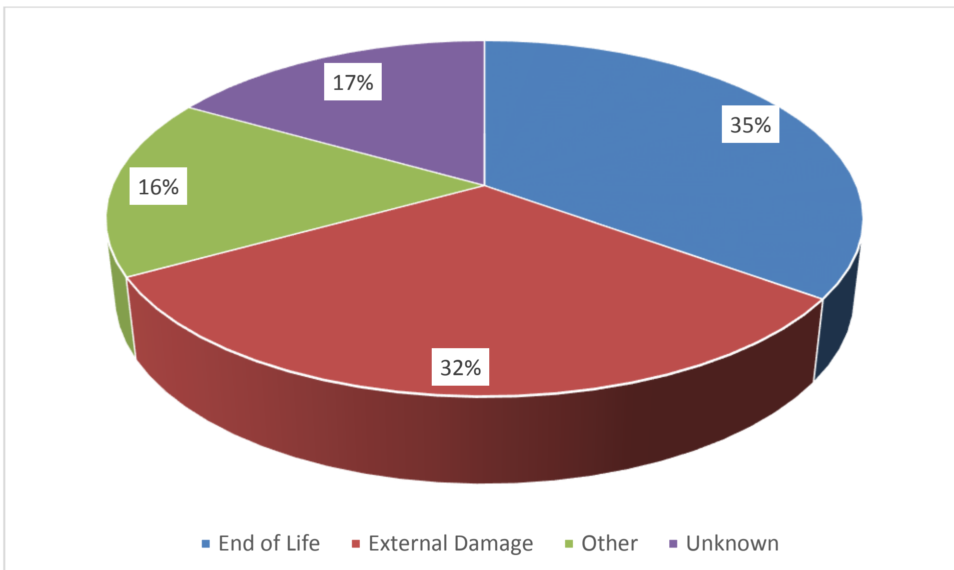


Figure 12: Root Cause Distribution for Failed Underground Transformers from 2012 to 2017

[3] See Exhibit 4A, Tab 2, Schedule 2.
[4] Corrosion, which is known to accelerate degradation and reduce the life of assets, represents 5 percent of these failures and is included in External Damage (see Figure 12).

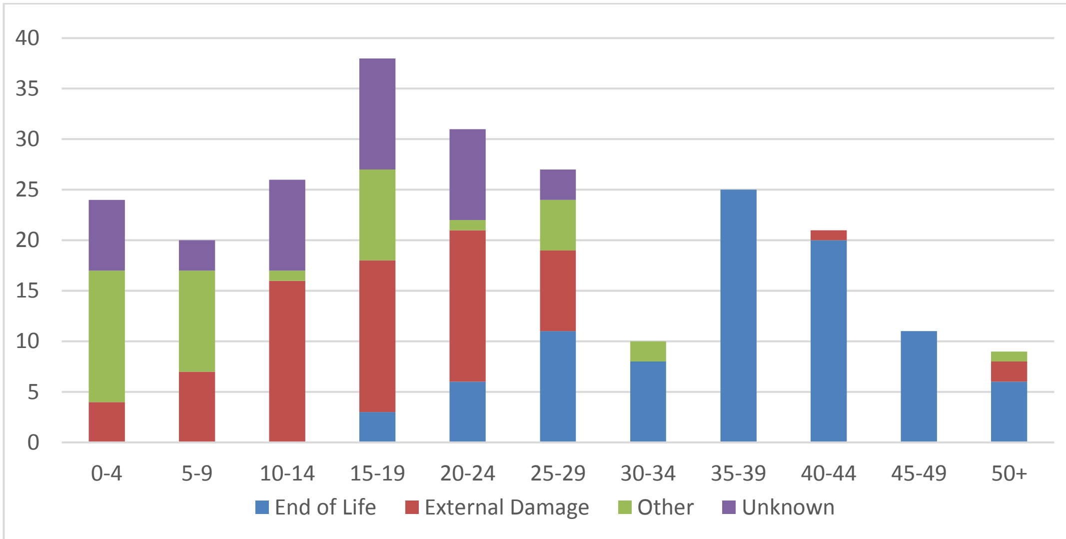


Figure 13: Age of Transformers at Time of Failure

Figure 14 shows the current age distribution of underground transformers in the Horseshoe area and what it will be in 2024 without investment. As of 2017, 19 percent of underground transformers in the Horseshoe area (i.e. 3,505 units) were at or beyond useful life. There are also a high number of transformers approaching their useful life (i.e. 33 years for submersibles and 35 years for padmount and vault). Without any replacement, the percentage of assets at or beyond their useful life will increase by more than 50 percent and reach 29 percent (5,355) by 2024. An increase in the number of transformers at or beyond their useful life will increase the risk of units failing and will erode and eventually reverse the improvements in reliability made in recent years. Additionally, without sufficient replacement, Toronto Hydro will face a backlog of transformers requiring replacement beyond 2024.

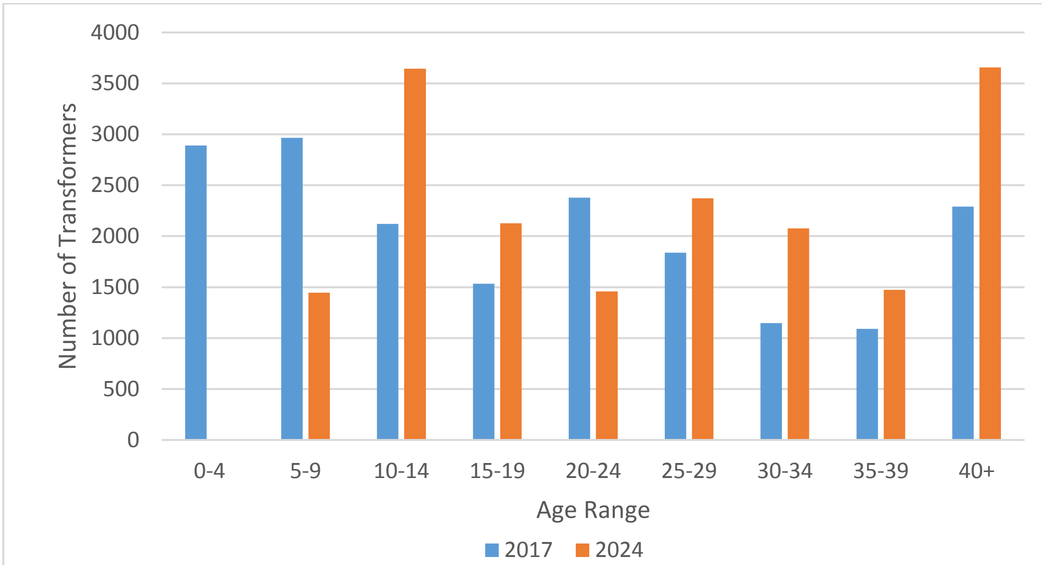


Figure 14: Age Distribution of Horseshoe Underground Transformers as of 2017 and In 2024 without Investment

A number of underground transformer failures in the Horseshoe area also resulted in oil leaks into the environment. Figure 15 below shows the total number of such oil spill incidents doubling over the last three years. Older transformers are at risk of having oil containing PCBs. Releasing oil containing PCBs (or oil on its own) into the environment may constitute a breach of the City of Toronto's Sewer Use By-Law, Ontario's *Environmental Protection Act* and, in some cases, the federal Canadian *Environmental Protection Act*. Toronto Hydro may be ordered to perform work or remediate any non-compliance under one or more of these regimes due to a single incident. A conviction would also likely have serious reputational consequences for Toronto Hydro. Importantly, leaks put communities and the public at risk of exposure to PCBs. During the 2015-2017 period, Toronto Hydro has been contacted by regulatory authorities with respect to oil spills and PCBs on a number of occasions, further highlighting the need to act proactively in this regard.

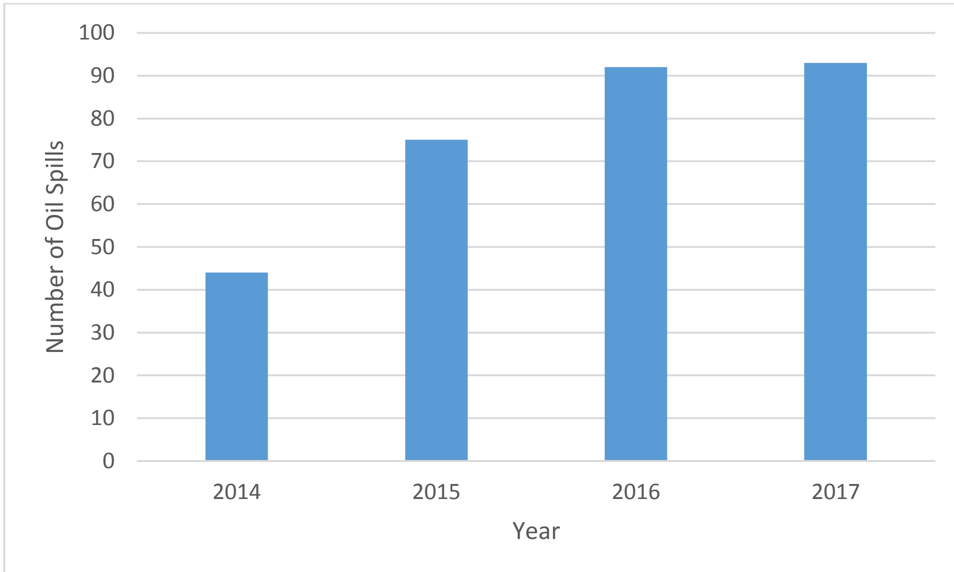


Figure 15: Number of Oil Spill Incidents from Underground Transformers in the Horseshoe Area

As of 2020, Toronto Hydro will have 1,458 underground transformers in the Horseshoe area that contain (or are at-risk of containing) PCBs. Toronto Hydro plans to inspect and replace these through this Program.

E6.2.3.3 Replacement of Underground Switches

Toronto Hydro also plans to replace switches as part of area rebuild projects. There are approximately 5,500 switches in service in the Horseshoe area.

Switches are used for load switching, isolation, and emergency power restoration procedures. Toronto Hydro's underground distribution system uses two types of switches: (1) Padmounted switches (air vented or sealed with SF_6 insulation) which are installed mainly next to boulevards and used for feeder switching; and (2) vault installed switches (air vented or sealed with SF_6 insulation) used for switching and transformer isolation in a vault. The useful life of these switches are 30 and 40 years, respectively.

Exposure to harsh environments may reduce switch lifespans. Padmounted switches are designed to be vented naturally through louvers under the hood of the enclosure, which provide a route for dust and road salt to enter the switching compartments and accumulate within the asset. Scheduled preventive maintenance, such as inspections followed by corrective CO_2 washing, is only effective in removing the excessive buildup of contaminants for a limited time. At the same time, repeated CO_2

washing contributes to the degradation of the switch's insulation strength which can lead to eventual failure. While routine maintenance is part of Toronto Hydro's asset management practice, it cannot be relied upon to extend the life of a padmounted switch in a sustainable manner.

Other sources of contamination include the concrete foundation upon which the padmounted switch rests, where primary cables are attached to the fusing and switching compartments. These cables may be tightly packed within the enclosure, creating an environment with tight clearances and an increased potential for moisture accumulation. As the ambient temperature changes, the trapped moisture condenses into water, dampening the dirt and other contaminants that are already present on the insulation surface. The surface then becomes conductive and may result in a flashover of the unit.

The result of a flashover is a near simultaneous ignition of all combustible material within the compartment. Flashovers can result in a discharge of electrical energy within the other compartments of the switch. This ultimately results in additional flashovers and combustion that leads to the total failure of the unit.

Figure 16 provides an illustration of how contaminants build up on a typical padmounted switch leading to a potential flashover.

Figure 16: Padmounted switch

Condition data for Air and SF_6 type underground padmounted switches are shown in Table 8. Data shows that 70 padmounted switches have at least material deterioration and should be considered for replacement as of 2017. The table also shows that without any capital renewal the number of switches with at least material deterioration is projected to approximately double by 2024 (141 switches) thus increasing the risk of failure due to deteriorated assets on the system.

Table 8: Asset Conditioning for Underground Padmounted Switches – Air and SF_6 Type in 2017 and 2024 without Investment

Condition	UG Switch – Padmounted Air		UG Switch – Padmounted SF_6		Total 2017	Total 2024
	2017	2024	2017	2024		
HI1 - New or Good Condition	381	355	263	263	**644**	**618**
HI2 – Minor Deterioration	19	29	0	0	**19**	**29**
HI3 – Moderate Deterioration	68	20	2	0	**70**	**20**
HI4 – Material Deterioration	29	5	0	0	**29**	**5**
HI5 – End of Serviceable Life	41	136	6	8	**47**	**144**
Unavailable	40	33	256	256	**296**	**289**
Grand Total	**578**	**578**	**527**	**527**	**1105**	**1105**

In Toronto Hydro's underground distribution system in the Horseshoe area, 6 percent of the outages between 2007 and 2017 were caused by switch failure, they can lead to significant public safety risks and extensive disruption to service for an extended period of time. For example, padmounted switches are commonly connected to the trunk portion of a feeder for load distribution and switching. When load is transferred from one feeder to another, individual switches are closed or opened so power can be diverted from one feeder to another. These actions cannot occur when a padmounted switch fails, leading to a significant negative effect on system reliability by causing an outage or extending a feeder outage to the bus level.

A summary of the ten-year reliability of the underground switches discussed in this Program is shown in Figure 17, Figure 18 and Figure 19. Proactive replacement of switches has helped moderate the frequency of outages caused by switch failure since 2012 as shown in Figure 17. However, the population of switches in service is aging and if Toronto Hydro does not maintain the current renewal pace, the utility expects that the current level of reliability performance will not be sustained and failure rates will increase.

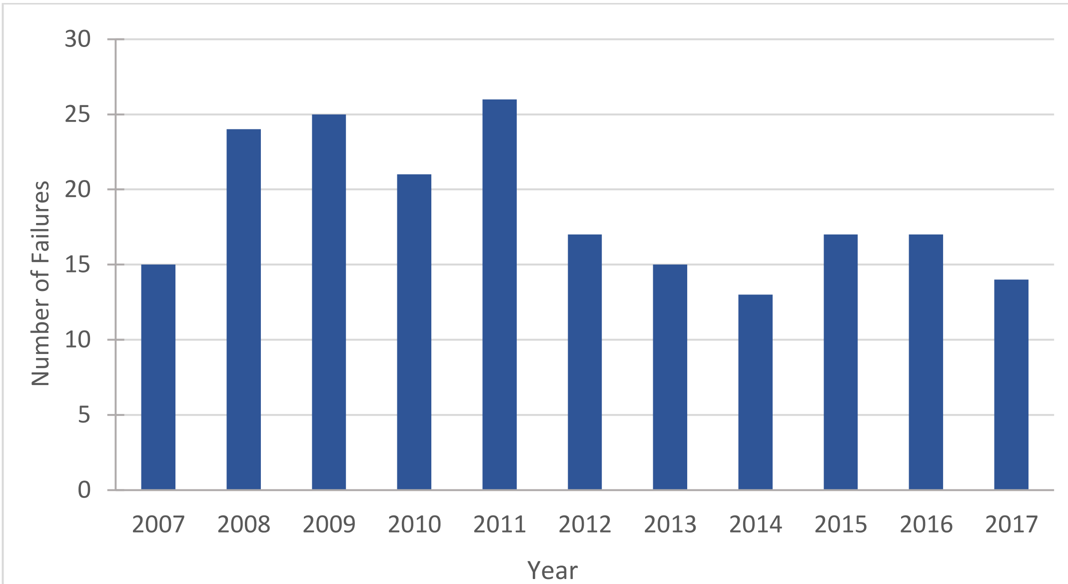


Figure 17: Ten-Year Trend of Outages due to Underground Switches Failures

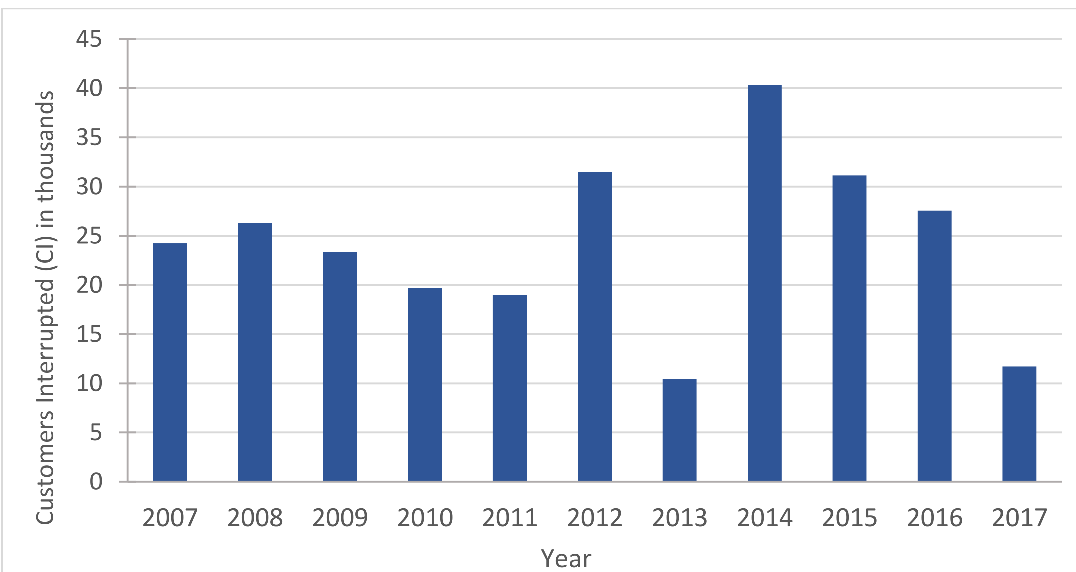


Figure 18: Ten-Year Trend of Total Customers Interrupted (CI) due to Underground Switches Failures

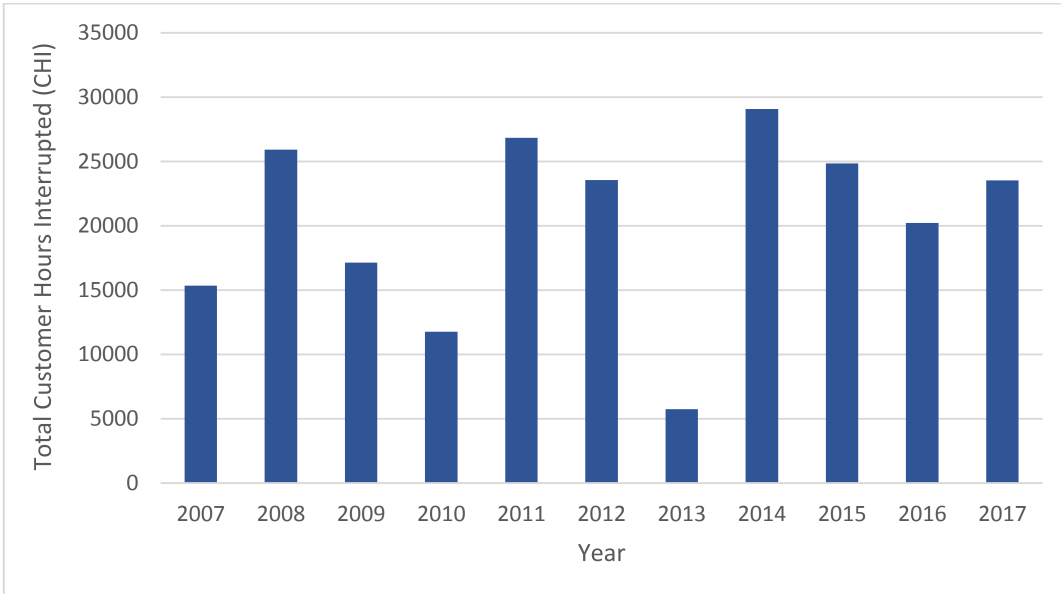


Figure 19: Ten-Year Trend of Total Customer Hours Interrupted (CHI) due to Underground Switches Failures

Figure 20 shows the age demographics of Toronto Hydro's padmount and vault switches, which have useful lives of 30 years and 40 years, respectively. As of 2017, 723 switches on Toronto Hydro's Horseshoe distribution system have already passed their useful life. Without intervention, 1,101 switches will be at or beyond their useful life in 2024. A significant increase in the number of switches at or past their useful life elevates the risks of units failing and will erode and eventually reverse the recent improvements in reliability shown in the figures above.

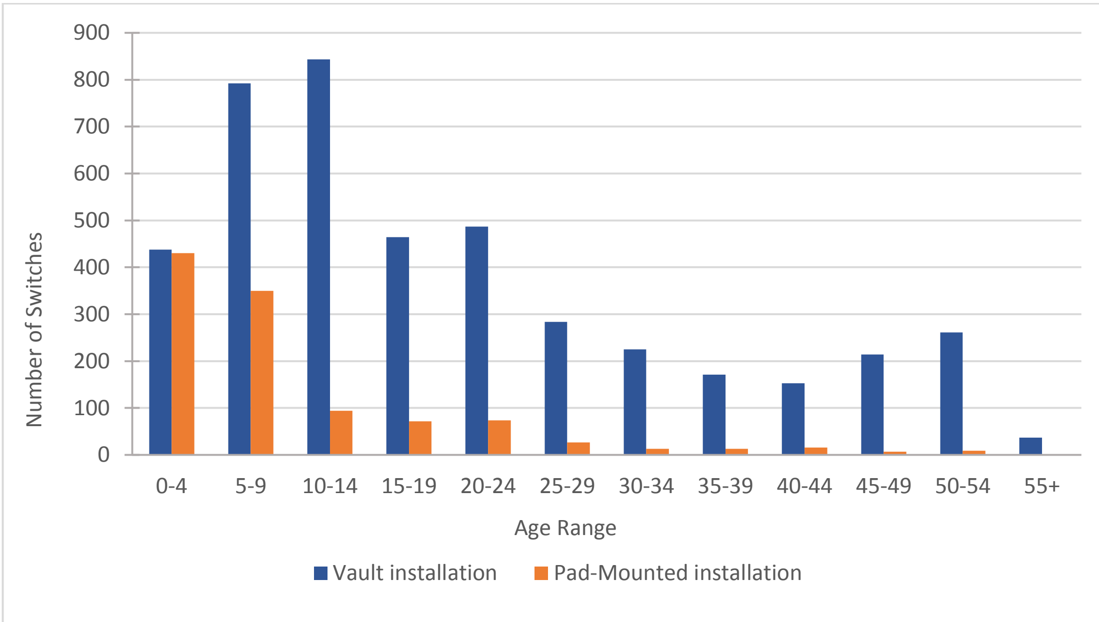


Figure 20: Underground Switches Age Demographic as of 2017

Toronto Hydro analyzed 45 padmounted air insulated switch units that failed between 2012 and 2017. As shown in Figure 21 below, the utility found that the majority of the units failed before their expected useful life of 30 years, with the highest number of failures occurring in the zero to nine years of age range, and the highest rate of failure occurring in the 15 to 24 years of age range. 40 percent of the failures analyzed are attributed to switches prematurely reaching their useful life due to external factors such as weather, contamination, and corrosion. When a switch fails, outages can range from 3 hours up to 17 hours and can affect an average of 1,300 customers.

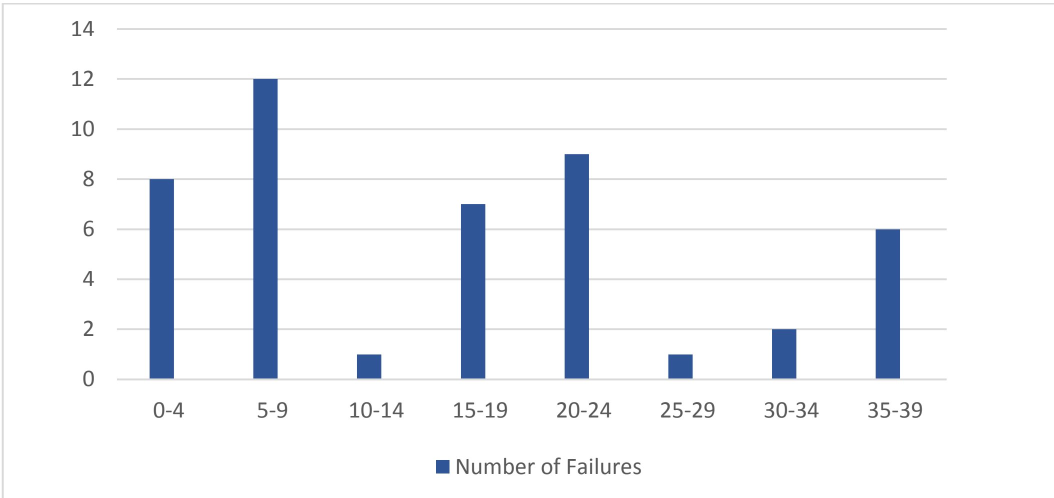


Figure 21: Underground Failures vs. Age Demographic

Of the 723 switches at or beyond their useful life as of 2017. Toronto Hydro plans to replace approximately 231 units over 2020-2024 as part of area rebuild projects under this Program. The utility expects to replace the remaining switches through the Reactive and Corrective Capital program[5] upon failure as they do not present environmental risks.

Given the failure risks associated with air insulated switch types, these units will be replaced with the new generation of SF_6-insulated switches. The new generation of switches has a stainless steel enclosure to prevent premature rusting and degradation of the cabinet. The unit includes welded viewing windows that mitigate SF_6 gas leakage into the environment. Programmable relays are also used instead of fuses for downstream circuit protection, eliminating the need for on-site switch re-fusing after a fault on the branch circuit. The units have internal grounding provisions making grounding easier and safer for crews in comparison to the external grounding elbows on the existing switches.

The new SF_6 switches enable SCADA capability for remote sensing, leading to increased system efficiency. This improves restoration time in the event of a power failure while avoiding costs associated with crews physically operating the switch on site.

Another advantage of padmounted SF_6 insulated switches is that it has the same circuit configuration and footprint as the existing air insulated padmounted units, thereby avoiding unnecessary cable

[5] Exhibit 2B, Section E6.7.

and civil construction work. Additionally, all external components of the SF_6 insulated switches are sealed and do not require costly, routine CO_2 washing to remove accumulated contaminants.

E6.2.4 Expenditure Plan

Table 9: Historical & Forecast Program Cost ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Underground System Renewal Horseshoe	115.5	80.7	83.1	70.0	71.4	93.0	88.7	90.3	93.1	95.2

E6.2.4.1 2015-2019 Variance Analysis

Over the 2015-2019 period, Toronto Hydro forecasts total spending of $420.7 million in the Underground System Renewal program, which is approximately $39 million lower than planned in the 2015-2019 Distribution System Plan. Nonetheless, Toronto Hydro is on pace to exceed the amount of cable and number of transformers installed related to the same plan.

Over the 2015-2017 period, Toronto Hydro spent $279.1 million and installed 720 kilometres of underground cable in duct, 1,555 transformers, and 213 underground switches, as shown in Table 10. Toronto Hydro plans to invest another $141.4 million in 2018-2019.

Table 10: 2015-2019 Volumes (Actual/Bridge) – Underground Circuit Renewal Horseshoe Program (Primary Electrical Assets)

Asset Class		Actuals			Bridge	
		2015	**2016**	**2017**	**2018**	**2019**
Cable	*km*	105	442	173	167	159
Transformers	*Units*	105	710	740	310	296
Switches	*Units*	47	79	87	43	41

During 2015-2017, Toronto Hydro invested at a higher pace than planned, installing an incremental 215 circuit-kilometres of primary cable and 611 transformers, and 16 fewer padmounted switches. The increase in the number of transformer units was due to an increasing need to address submersible transformers that were at risk of containing PCBs, had deteriorated in condition, and posed an unacceptable risk to the environment due to oil leaks. This increase was triggered in part by improvements Toronto Hydro made to its inspection forms and processes, resulting in a more accurate picture of the condition of submersible transformers and number of identified leaks. The higher pace of cable replacement was tied to this same issue, as Toronto Hydro worked to prioritize rebuild projects that addressed submersible transformers.

More broadly, variances in area rebuild programs such as this can be attributed in part to changes in the scope of work as projects moved from high-level estimates to detailed designs. These changes are anticipated for complex construction projects and typically result from a more detailed review of the scope of work and execution needs during the design phase. For example, designers may identify additional or fewer assets that should be included in a project, interference with other utilities and a resultant need to adjust the scope, additional restoration costs, etc., that influence the final cost of a project.

E6.2.4.2 2020-2024 Forecasts

Toronto Hydro plans to spend $460.3 million in this Program over the 2020-2024 period. The 2020-2024 forecast expenditures are based on Toronto Hydro's historical unit costs trends and experience gained executing this type of work over the last three years. The estimated volumes for major underground asset replacements during the 2020-2024 period are shown in Table 11.

Table 11: 2020-2024 Estimated Volumes (Forecast) – Underground Circuit Renewal (Primary Electrical Assets)

Asset Class		Forecast					
		2020	2021	2022	2023	2024	Total
Cable	*km*	103	96	96	98	98	**491**
Transformers	*Units*	407	380	380	387	387	**1,941**
Switches	*Units*	49	45	45	46	46	**231**

The forecasted volumes are estimates based on a preliminary selection of areas targeted for complete rebuilds and spot replacements.

Four types of work are carried out through this Program. They include:

- **Area Rebuilds:** Rebuild projects are prioritized based on the historical failure of major assets (such as cable and transformer) on the feeder, the concentration of assets in deteriorated condition or at or beyond useful life, and potential reliability impact on customers supplied by the feeder. Rebuilding entire areas is intended to ensure proper coordination of work and efficient mobilization of crews as it is in the customers' interest to undergo only one outage due to planned capital work as opposed to numerous outages during reactive work due to failure. Through these projects, assets connected to a feeder (e.g. cables, transformers, and switches) will be replaced to meet current standards such as cable installed in concrete encased ducts, transformers, padmounted switches.

- **Area Rebuilds with Voltage Conversion:** Where a feeder identified for renewal through area rebuilds is operating on 4.16 kV and 13.8 kV voltages, it will be converted to 27.6 kV. Toronto Hydro plans to perform renewal projects on 69 feeders, of which 11 feeders identified for voltage conversion. Figure 22 depicts the location of the areas with direct buried cable and the transformers at or beyond their useful life containing or at risk of containing PCBs.

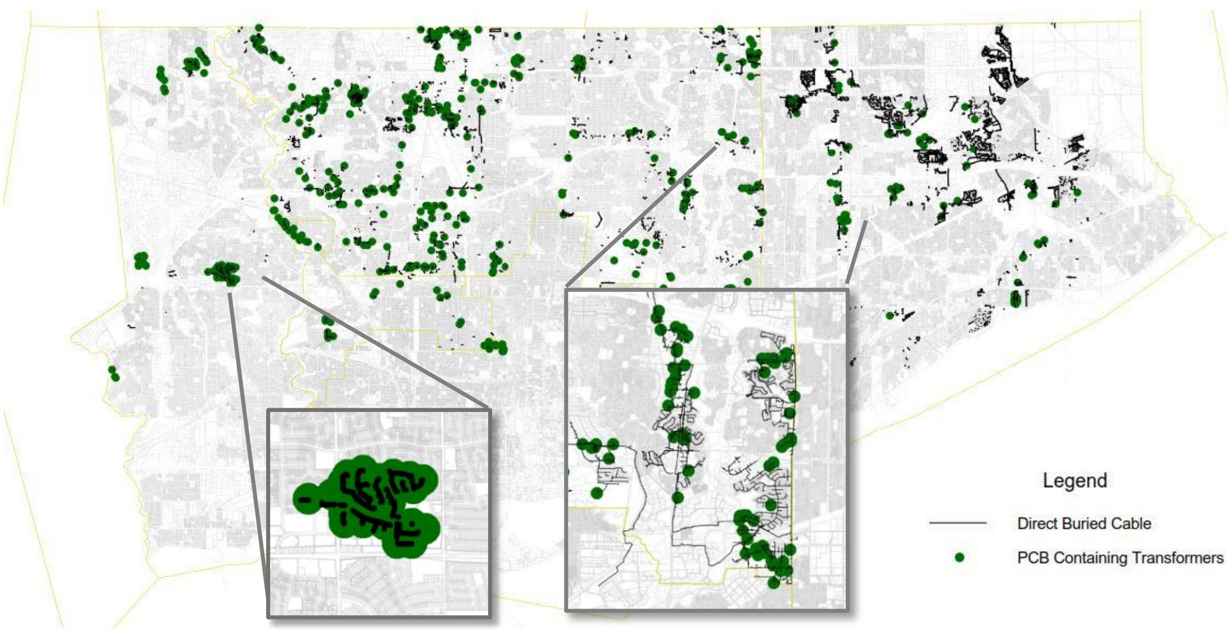


Figure 22: Planned Underground System Renewal Work Areas

- **Spot replacement:** Transformers that are not part of area rebuilds and in need of replacement will be addressed on a spot, like-for-like projects.

Whenever possible, work under this Program is combined or coordinated with projects from other programs (such as overhead renewal and rear lot, conversion) in the same area. Underground renewal projects are broken into civil and electrical phases, and those with significant amounts of civil work are broken down further into sub-phases for better manageability and coordination of resources, especially since all civil work is performed by contractors.

Equipment in the same area and fed from the same Toronto Hydro feeders is coordinated in terms of replacement schedule and sequencing. This approach reduces disruption of supply and requires less mobilization of resources to the same area. Reduced disruption to feeders translates into fewer outages for customers, and improves project efficiencies.

In addition, any voltage conversion underground work is coordinated with stations maintenance. This allows Toronto Hydro to eventually decommission Municipal Stations prior to any major maintenance or renewal investments. From a continuous improvement perspective, voltage conversion from 4.16 kV or 13.8 kV to a 27.6 kV system has the following benefits, which can lead to improved power quality and distribution efficiencies:

- higher voltage distribution lines can carry more power over long distances, meaning the overall distribution system will require fewer municipal substations; and
- less voltage drop at the end of the line and less line losses for the same power delivered.

Once projects are scoped at a high level, they undergo a field inspection in order to validate the scope of work, identify third party conflicts, and refine estimates before design finalization. Through this process, projects identified for renewal may be subject to change, and poorly performing feeders that demonstrate higher risks may take priority.

E6.2.5 Options Analysis

E6.2.5.1 Option 1: Spot replacement of transformers in deteriorated condition at or beyond their useful life

As of 2017, 19 percent of the transformers in the underground Horseshoe distribution system were at or past their useful life. Without investment, this percentage will increase by more than 50 percent to 29 percent by 2024. This option proposes, at a minimum, to replace all transformers that are at or beyond their useful life that contain or are at risk of containing PCBs to address reliability risks and significantly reduce the risk of releasing PCBs into the environment through oil leaks. Under this approach, Toronto Hydro would maintain the percentage of assets past their useful to 2017 levels at 19 percent.

As of 2017, 400 transformers have at least material deterioration (HI4 and HI5). Without any capital investment, this number is expected to triple to 1,203 by the end of 2024. Not investing in asset renewal will increase reliability risks on the distribution system and run the risk of negative environmental impacts from asset failure as the transformers continue to deteriorate. Under this option, Toronto Hydro plans to replace all transformers that have at least material deterioration.

However, Toronto Hydro would not be able to maintain the recent improvements made to reliability on the underground system. As of 2017, 77 percent of the direct buried XLPE cables were at or beyond their useful life. Without a proactive solution to address or replace high risk direct buried XLPE cables, by 2024, 90 percent of these cables will be at or past their useful life. This will create scenarios such as continuously failing cables, such as discussed in Section E6.2.3.1. Customers will experience an increase in outages and customer hours interrupted.

Under this option, cables will be replaced reactively through the Reactive and Corrective Capital program.[6] The costs associated with reactively repairing cables significantly exceed planned replacements, particularly when increasing operational and maintenance costs are taken into account. Many challenges are associated with reactive repairs of direct buried cables. As faulted cables are repaired with a splice, which introduces weak points into the cable segments and renders cables more susceptible to future failures.

The spot replacement of all underground PCB transformers units would cost Toronto Hydro an estimated $123.4 million (without EAR or Inflation).

E6.2.5.2 Option 2: Area rebuilds

Under this option, Toronto Hydro would carry out area renewals in areas experiencing poor reliability as a result of direct buried cables, and which have transformers at or beyond useful life that contain (or are at risk of containing) PCBs. To maintain recent reliability improvements, Toronto Hydro plans to replace all 368 circuit-kilometres of direct buried XLPE cable in the underground system through area renewal projects.

However, under this approach, Toronto Hydro would not be conducting spot replacements on a planned basis, and would be running assets to failure and replacing them through the Reactive and Corrective Capital program.[6] As of 2017, 19 percent of the transformers in the underground Horseshoe distribution system were at or past their useful life and without investment, this will increase by more than 50 percent to 29 percent by 2024. Under this option, a large number of such transformers will remain on the system, increasing the risks of units failing and eroding and

[6] Exhibit 2B, Section E6.7.

eventually reversing the recent improvements in reliability. This would also pose an environmental risk as transformers will remain in service that may contain PCBs. Releasing oil containing PCBs (or oil on its own) into the environment may be a breach of the City of Toronto's Municipal Code – Sewer by-law, Ontario's *Environmental Protection Act* and/or, the federal *Canadian Environmental Protection Act*. Toronto Hydro may be ordered to perform work or remediate any non-compliance under one or more of these regimes as the result of a single incident. In sum, the remediation and response costs associated with failed assets are higher than the cost associated with proactive replacement.

E6.2.5.3 Option 3 (Selected Option): Area rebuilds and Spot replacement of transformers at or beyond their useful life

This option is in major part driven by the reliability needs of the system associated with deteriorating and legacy (direct buried) cable installations. Proactive underground renewal carried out through Toronto Hydro's Underground System Renewal program has improved the system reliability, reducing the number of failures from 180 in 2013, to approximately 120 in 2017. However, although the number of failures has decreased, the number of customer interruptions and the hours of customer interruption have decreased at a lower rate. Therefore, Toronto Hydro proposes to continue proactively replacing poor performing assets at or beyond their useful life to mitigate reliability and environmental risks.

Under this option, Toronto Hydro proposes 69 area renewal projects to replace 215 circuit-kilometres of direct buried XLPE cable, transformers at and beyond their useful life that contain or risk containing PCBs, and switches at or beyond their useful life. Through these projects, assets connected to a feeder (e.g. cables, transformers, and switches) will be replaced to meet current standards such as cable installations in concrete encased ducts, transformers, padmounted switches. Despite replacing 215 circuit-kilometres under this option, Toronto Hydro will still have approximately 153 circuit-kilometres of high risk direct buried XLPE cable in the system past 2024.

Under this option, Toronto Hydro would replace approximately 600 transformers at or beyond their useful life containing or at risk of containing PCBs, through rebuild projects. The remaining transformers at or beyond their useful life not addressed through these rebuilds would be replaced on a spot, like-for-like basis to mitigate the environmental risks associated with leaking oil containing PCBs.

As of the end of 2017, Toronto Hydro had 723 switches at or beyond their useful life. Through this option, Toronto Hydro would replace approximately 231 units over 2020-2024 as part of the area rebuild projects. The utility expects to replace the remaining switches through the Reactive and Corrective Capital program upon their failure as they do not present significant environmental risks.[7]

This option could reduce the number of outages experienced due to cable fault and the lengthy process of fault locating on direct buried cable, as described in Section 0.

E6.2.5.4 Option 4: Replace transformers at or beyond their useful life that contain or are at risk of containing PCB, all of the highest risk direct buried cables, and assets with at least material deterioration.

The utility will replace all high risk direct buried cables that contribute to negative reliability impacts in the Horseshoe area. This will allow Toronto Hydro to maintain its recent reliability gains. Under this option, Toronto Hydro will replace all transformers at or beyond their useful life that contain or are at risk of containing PCB (as described in Option 1). This work will minimise the risk of environmental impacts resulting from potential PCB oil spills, and help ensure the utility remains compliant with applicable environmental requirements.

Additionally, under this option, Toronto Hydro will proactively replace all aged assets in the underground system (cables in concrete encased ducts or PVC duct, non-PCB transformer, and switches), as well as the 149 switches, and the non-PCB risk transformers (among the 1193 that will reach at least material deterioration, i.e. HI4 and HI5, by 2024).

This alternative would allow Toronto Hydro to maintain and improve reliability in the Horseshoe area by reducing asset failure risk, and minimize environmental risks. While this option is preferred from a risk-mitigation perspective it is a higher cost option that does not represent the optimal balance between customer needs with respect to reliability and price of service.

E6.2.6 Execution Risks & Mitigation

Project execution begins with the civil phase of the underground renewal project. Electrical construction commences upon completion of the civil work. The risks associated with the Underground System Renewal program include, but are not limited to:

[7] Exhibit 2B, Section E6.7

- Unforeseen updates and changes to existing road moratoriums imposed by the City of Toronto in areas where Toronto Hydro intends to perform underground renewal work. In this case, Toronto Hydro will mitigate the risk by through close coordination with the City of Toronto and its representatives, i.e. Ward Councillor, Business Improvement Area delegates.
- Unforeseen weather conditions that may affect Toronto Hydro's ability to take planned outages (i.e. heat restrictions), or construction in the fall and winter due to harsh weather (i.e. storms or extreme cold periods).
- Third party conflicts may require Toronto Hydro to modify its trench route due to underground space limitations, resulting in higher than estimated project costs. Toronto Hydro mitigates this risk by engaging with third parties in the design phase to ensure close coordination and alignment. For instance, Toronto Hydro's participation in the Toronto Public Utility Coordinating Committee meetings is an effective mean of identifying and avoiding third party conflicts.
- Some projects require work within customer owned civil structures or consent on easements from customers to install distribution assets in private property. In the case of customer owned civil structure, the customer may have to perform civil rebuild work prior to Toronto Hydro commencing its activities, causing project delays. Toronto Hydro mitigates this risk by inspecting customer owned assets during the design phase and communicating to the customer by issuing Customer Advice Form ("CAF") for any deficiency identified. This ensures that customers are given advanced notice and have an opportunity to raise their concerns and address the civil work in a timely manner. For permits and easements, Toronto Hydro will reach out and engage customers early in the design phase of the project to account for the possibility of delays. This gives customers the opportunity to meet with the utility to discuss the details of the project and any concerns. This proactive customer engagement approach has been successful in minimizing construction delays.
- All underground projects are designed and constructed in accordance with approved Toronto Hydro's standards and specifications. However, in certain cases, deviations or special considerations are needed during design. Toronto Hydro will follow its established process for all deviation requests so that they can be assessed and approved by the standards department in a timely manner during the design phase. This process helps to prevent delay or costly rework due to operational issues during the execution of the projects.

E6.3 Underground System Renewal – Downtown

E6.3.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 0	**2020-2024 Cost ($M):** 122.0
Segments: Cable Chamber Renewal, Underground Cable Renewal, Underground Residential Distribution Renewal	
Trigger Driver: Failure Risk	
Outcomes: Reliability, Environment, Safety	

The Underground System Renewal – Downtown program (the "Program") addresses aging, deteriorating and poor performing underground distribution assets in the downtown core[1] area of pre-amalgamation City of Toronto. Material asset deterioration and aging have been significant drivers of Toronto Hydro's ramp-up in capital investment since the late 2000's; with the largest renewal investment proactively addressing declining asset condition and performance in the more dispersed inner suburbs (i.e. the Horseshoe area) of Toronto.[2] This Program introduces equivalent rebuild and replacement activities for deteriorating and functionally obsolete underground assets in the City's core. To date, these assets have been managed through a combination of preventative maintenance,[3] targeted refurbishment, and in the event of asset failure, reactive and corrective capital[4] and maintenance.[5] The average condition of these assets (in addition to other pressures discussed below) necessitates a targeted renewal strategy; targeting worst performing and highest risk locations.

The Program is designed to deliver reliability improvements, mitigate asset failure and public safety risks within the downtown core by: (1) replacing obsolete underground lead covered cables with standard tree retarded cross-linked polyethylene cables, (2) reconstructing cable chambers (or components; e.g. roofs, duct banks) at risk of failure due to poor structural conditions, and (3) proactively replacing end-of-life and obsolete underground residential distribution ("URD") assets -

[1] This Program does not address network units or network vaults. Network equipment is addressed within the Network System Renewal program (Exhibit 2B, Section E6.4)
[2] See Exhibit 2B, Section E6.2
[3] See Exhibit 4A, Tab 2, Schedules 1, 2, and 3 Preventative and Predictive Maintenance programs
[4] See Exhibit 2B, Section E6.7
[5] See Exhibit 4A, Tab 2, Schedule 4 Corrective Maintenance

unique, looped distribution design serving primarily low-rise residential customers in limited areas of the pre-amalgamation City of Toronto.

The Program is grouped into the three segments summarized below:

- **Underground Cable Renewal:** This segment replaces the PILC Leakers & Piece-outs program[6] which Toronto Hydro is on track to complete in the 2015-2019 period. While the PILC Leakers & Piece-outs program addressed immediate safety and operational risks related to known leaking cables and congested chambers, this Program focuses on the longer-term challenge of gradually removing the large population of these deteriorating and obsolete cable types from the system. Specifically, the segment will replace obsolete underground lead covered cables with standard tree retarded cross-linked polyethylene cables. Based on the age and condition of Toronto Hydro's population of lead cables, the utility anticipates a decline in reliability performance and an increase in operational and safety risks. Toronto Hydro recognizes the customer value stemming from the removal of these high risk, lead based cables, and plans to invest $89.7 million over the 2020-2024 period to replace approximately 2.5 percent of 1,100 km paper-insulated lead-covered ("PILC") cable and 24 percent of 220 km asbestos-insulated lead-covered ("AILC") cable. It is estimated that these replacements will prevent 2,800 Customer Interruptions ("CIs") and 8,700 Customer Hours Interrupted ("CHI") for downtown customers (mostly commercial customers) over the 2020-2024 period. This will also decrease the presence of designated substances (i.e. lead and asbestos) on the grid. These cables are a critical part of the distribution infrastructure serving large customers (e.g. major financial institutions) and other reliability-sensitive customers (e.g. multi-residential high-rises) in the downtown core. To manage the pacing of investment in this segment, Toronto Hydro has begun to predict with increasing accuracy and precision the cable segments at the highest risk of failure. Combining this risk-based prioritization with the amount and criticality of the load served by each feeder allows Toronto Hydro to direct expenditures to the projects with the greatest customer value. **/C**
- **Cable Chamber Renewal:** This segment involves the reconstruction of cable chambers or cable chamber components (e.g. roofs, duct banks) that are at risk of failure due to their poor structural condition. To date, Toronto Hydro has managed the reconstruction of cable chambers reactively. However, due to the growing number of failing chambers and the

[6] EB-2014-0116, Exhibit 2B, Section E6.2

complexity of chamber reconstruction work, Toronto Hydro is introducing a planned renewal segment in 2020. The vast majority of chambers in HI4 (material deterioration) and HI5 (end of serviceable life) condition are located in the downtown core, where there is heavy vehicular and foot traffic and a high density of circuits running through each chamber. These chambers can hold up to 29 circuits, supplying up to 3,500 customers per chamber. Typically, these are chambers that supply large condominiums with many suite-metered residential customers. Chambers can also supply one or several large industrial or commercial customers. As of 2017, 16 cable chambers were in HI5 condition and 188 were in HI4 condition. To address this growing backlog, Toronto Hydro's goal is to reach zero cable chambers in HI5 condition by 2024 (this does not include chambers that actively become HI5 over the 2020-2024 period Toronto Hydro has approximately 10,700 cable chambers, including 5,900 in the downtown area. Toronto Hydro plans to execute an estimated 15 chamber rebuilds, 24 chamber roof rebuilds, and three chamber abandonments per year during the 2020-2024 period. Toronto Hydro also plans to replace 200 cable chamber lids per year to address potential public safety risks in high traffic areas. The total forecast cost for this segment is $29.1 million.

- **Underground Residential Distribution ("URD") Renewal:** This segment is focused on the URD system – a unique, looped distribution design serving primarily low-rise residential customers in limited areas of the pre-amalgamation City of Toronto. Toronto Hydro has recently seen a sharp increase in the volume of corrective work requests on this system, along with an increase in outage frequency and an observed deterioration in condition. The utility plans to proactively replace end-of-life and obsolete URD assets that contribute to the deterioration of system reliability, namely switching and non-switching vaults, switches, and transformers. Toronto Hydro's objective for 2020-2024 is to invest the amount needed to maintain average reliability performance for the customers served by this system. The utility aims to achieve this by targeting the worst condition and most critical assets. Toronto Hydro is budgeting an estimated $3.2 million over the 2020-2024 period to address the civil and electrical assets at three to four URD vault locations per year.

The Underground System Renewal – Downtown program for the 2020-2024 rate period is also aligned with the objectives of addressing environmental and safety risks associated with distribution assets containing PCB or asbestos. The total proposed investment for the Program in 2020-2024 is $122 million.

1 ## E6.3.2 Outcomes and Measures

2 **Table 2: Outcomes & Measures Summary**

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) and reduces the risk of lengthy outages on feeders serving thousands of downtown customers, including large, critical customers in the core while improving long-term system health by: o Replacing an estimated 27 kilometres of PILC cable that is subject to a high risk of failure. /C o Rebuilding cable chambers known to be in HI5 and HI4 condition. o Reducing the average number of splices and transition joints on downtown feeders.
Environment	• Contributes to improving Toronto Hydro's Spills of Oil Containing PCBs measure and reducing the risk of toxic exposure to the environment by: o Eliminating PILC cable containing oil and potentially PCBs; o Eliminating AILC cable containing asbestos; and o Eliminating PILC and AILC cable containing lead.
Safety	• Contributes to the utility's public and employee safety objectives and performance by: o Replacing 200 chamber lids per year to reduce the risk of injury or property damage from cable chambers lid ejections; o Eliminating safety hazards such as poor structural integrity and cable congestion; o Reducing the safety hazards related to the structural failure of cable chambers in high-traffic areas by replacing or abandoning HI5 and HI4 condition chambers and chamber roofs; and o Reduce the potential exposure to lead and asbestos classified as Designated Substances under the *Occupational Health and Safety Act* (O. Reg. 490/09 Sections 5 and 10). o Safely hand and dispose of asbestos (and lead) as prescribed in the *Ontario Occupational Health and Safety Act* (Reg. 833) and the *Canadian Environmental Protection Act*.

E6.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Functional Obsolescence, Safety, Environmental Risk

The Underground System Renewal – Downtown program is driven by the failure risk of key assets that negatively impact reliability and safe operation within the downtown core. Historically, these assets have shown high reliability but have now become obsolete or pose a risk to the public and the environment. Many of these assets are vital to supply critical customers in the downtown district. These are of particular concern for large commercial customers who prioritize reliability over cost and residential customers who prioritize cost over reliability as demonstrated through the customer engagement surveys.

E6.3.3.1 Underground Cable Renewal

The Underground Cable Renewal segment will focus on replacing obsolete primary PILC and secondary AILC underground cables at a high risk of failure with tree retarded Cross-Linked Polyethylene ("TRXLPE") cable. These cables are typically found in the pre-amalgamation City of Toronto, especially throughout the downtown core. This segment replaces the PILC Leakers & Piece-outs program, which Toronto Hydro is on track to complete in the 2015-2019 period.[7] The PILC Piece-out & Leakers program was designed to deal with the rapid emergence of a large backlog of leaking cables, which present a safety hazard to Toronto Hydro crews. The previous program addressed approximately 15 km of PILC cable where numerous critical deficiencies had been noted through inspections. Having dealt with the immediate safety and operational risks related to known leaking cables and congested chambers, Toronto Hydro is now shifting its focus to the longer-term challenge of gradually removing the large population of these deteriorating and obsolete cable types from the system.

PILC and AILC cables were initially installed in the downtown system due to their high reliability and long life span. However, they are becoming obsolete across the industry due to environmental and health and safety concerns (which includes the challenge of safely and skillfully working with lead). Major urban utilities are proactively eliminating lead cable, and only one PILC supplier remains (there

[7] Exhibit 2B, Section E4

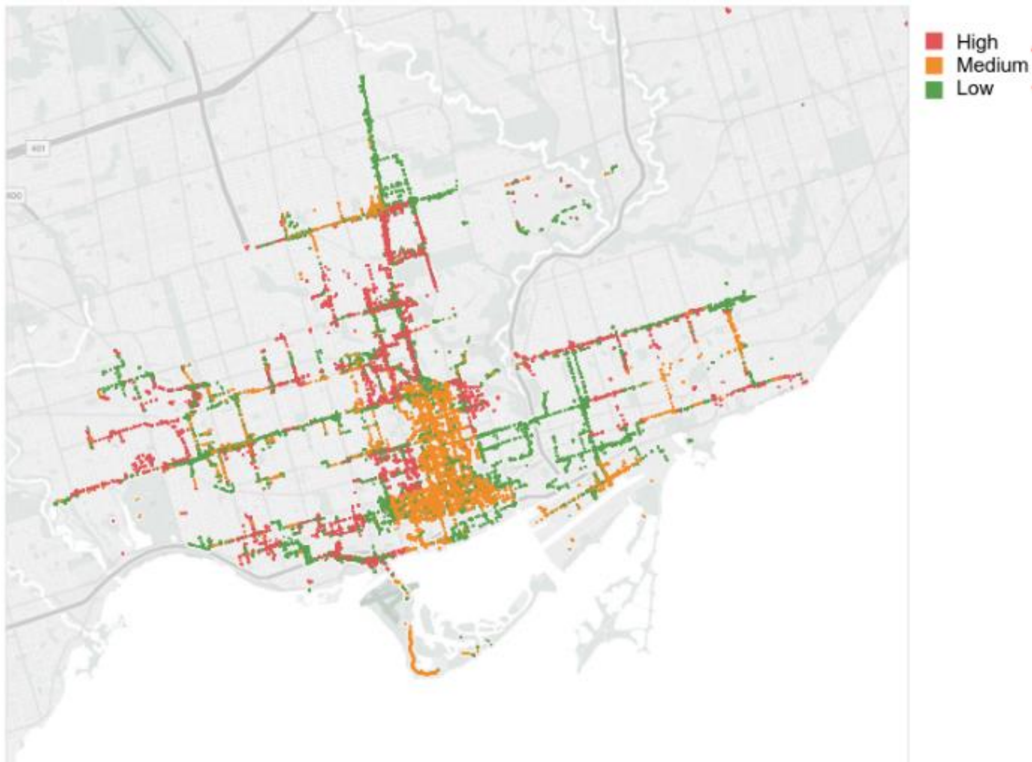
are no longer any suppliers of AILC cables). As a result, approximately 42 percent of all PILC cables and 68 percent of all AILC cables in the system are more than 30 years old. Aged cables are showing signs of deterioration, including pin holes, cracks, and leaks.

Other utilities across North America have recognized the customer value stemming from the removal of high-risk lead-based cable. For example, the U.S. Environmental Protection Agency ("EPA") has recognized utilities ConEd of New York and PSE&G of New Jersey for their efforts to remove lead cable from their system. ConEd began their replacement efforts in the 1990s to remove PILC. At the end of 2015, based on an average rate of 120 miles of cable replacement per year, ConEd had 10 percent of PILC cable remaining in its system. PSE&G successfully removed 1.3 million pounds of lead from PILC.

Toronto Hydro is planning to remove approximately 24 percent of AILC cable (53 circuit kilometres of 220 kilometres) and 2.5 percent of PILC cable (27 circuit kilometres of 1,100 kilometres) between 2020 and 2024. The cables will be replaced based on the risk level associated with each cable segment. A statistical method has been developed by Toronto Hydro to prioritize primary cable segments to improve reliability. This was accomplished to generate a prioritized list of high risk cable segments. Various factors, including historical failures, number of splices on feeders, age and customer base, are used to determine cable segment risks. In addition, as primary cables and cable segments are being tested or replaced, Toronto Hydro will re-prioritize at-risk feeders. Where at-risk primary cable sections are identified, this will drive the replacement of the legacy type AILC cable that is connected downstream of these cable sections. /C

PILC cable consists of a conductor surrounded by oil-impregnated paper insulation, lead sheath and an optional linear low-density polyethylene jacket. There are approximately 1,100 circuit-kilometres of 13.8 kV PILC underground cable on the system. These cables are used as the primary service cable in the downtown core, connecting transformer stations to customers or Toronto Hydro owned distribution transformers (these transformers step down voltage and supply residential customers). Approximately 60 percent of all primary cable in the downtown core is PILC cable and approximately 40 percent is XLPE cable.

Figure 1 shows the distribution of PILC cable in the City of Toronto and the level of risk associated with them based on the type of cable, age, and condition (including number of splices and historical faults). The highest risk cables are found both within and around the downtown core, while the medium risk cables are heavily concentrated within the core, and the Financial District in particular.



1 **Figure 1: PILC Cable Distribution Risk**

2 AILC cables are found downstream of these PILC cables. They consist of a conductor (typically copper)
3 surrounded by asbestos-based insulation and covered in a ductile lead sheath. These cables account
4 for 64 percent of the secondary voltage connections within the secondary network system.[8]

5 Figure 2 represents the general distribution of all AILC cables in the city of Toronto and their level of
6 risk based on the associated age and condition of primary assets.

[8] For more information on the Secondary Network System, please refer to Exhibit 2B, Section D2.2.3 of the DSP.

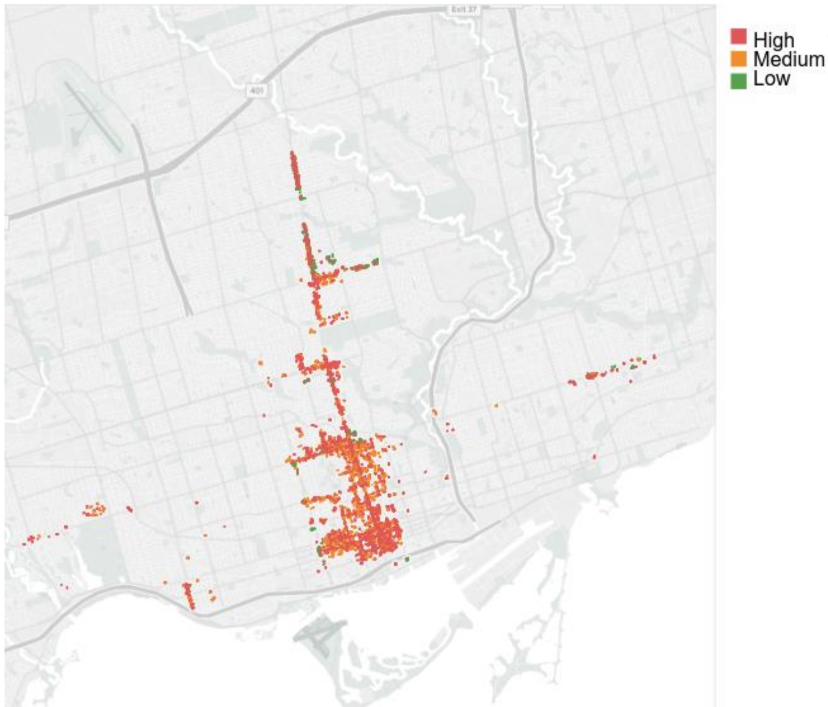


Figure 2: AILC Cable Distribution and Criticality Risk

The increasing non-uniformity of cable types in the system drives the failure risk of these cables. Due to the obsolescence of PILC and AILC cables, the necessary interventions and modifications to downtown feeders have unavoidably resulted in the splicing of XLPE cable into sections of PILC and AILC cable. Splicing is the process used to maintain the connectivity between two cable sections or cable types. It is typically carried out when a longer cable is required, a branch is required, or part of an old cable is replaced with a new cable. Although cables have a long life expectancy, cable splices do not. The failure risk does not stem from the cable itself, but from the splices which are a result of combining cable types on any given feeder. This increases the risk of failure on the system as the majority of Toronto Hydro feeders with PILC and AILC cables do not consist of 100 percent PILC or AILC; instead, a mixture of cable types is common (e.g. PILC and XLPE, or AILC and XLPE).

Table 4 summarizes the programs and types of work that lead to a mix of cable types on Toronto Hydro feeders:

Table 4: Work conducted on Toronto Hydro feeders that lead to mixed cable types

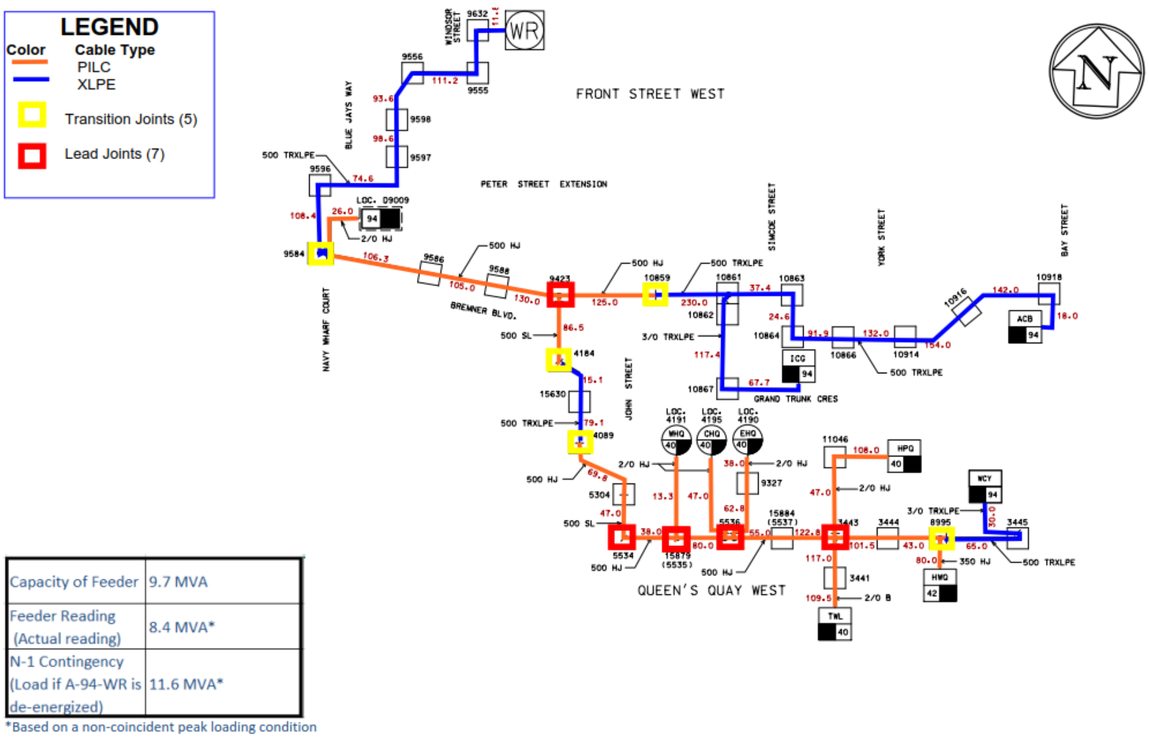
Programs	Description of Work
Customer Connections (Exhibit 2B, Section E5.1)	• Customers are connected with new XLPE type cable spliced to existing PILC cable. • This also includes the addition of XLPE cable for secondary network type connections (replacement of AILC cable).
Reactive Capital (Exhibit 2B, Section E6.7)	• Cable faults or leaking cables are repaired by cutting or piecing-out faulty sections, and replaced with new XLPE cable, using splices.
Load Demand (Exhibit 2B, Section E5.3)	• Cable sections that require upgrades due to capacity limitations are replaced with new XLPE cable.
Network System Renewal (Exhibit 2B, Section E6.4)	• Circuit reconfigurations, required to achieve network stability and improved reliability, involve splicing new secondary and primary XLPE cable into existing AILC and PILC cables. • Network unit replacements include the replacement of critical AILC or PILC type cables that are connected to these units. • Cables to the most upstream cable chamber are replaced resulting in the introduction of splices.

As a result of the Table 4, lead cables become more brittle and prone to cracking, and the number of transition joints or splices increases over time. These splices create and add weak points along the cable and introduce additional failure risk to already aging cables serving many large and critical loads. Consequently, feeder life expectancy and probability of failure worsen. As the weakest point on a feeder, a cable joint may fail primarily due to mechanical stress or water ingress.[9] A fault in the joints may also impact the conductor, insulation, or sheath. For instance, the sheath of the joints can develop corrosion due to thermal stresses of the feeder, which increases the chance for moisture to seep into the joint and consequently cause a failure.

The introduction of mixed insulation types also introduces different dielectric strengths or inconsistent magnetic fields at the joints which would result in higher losses or insulation breakdown. These transition joints (splices) are critical to the continuity of the dielectric properties and magnetic

[9] Nemati, H.M., Sant'Anna, A., & Nowaczyk, S. (2015). Reliability Evaluation of Underground Power Cables with Probabilistic Models, *The 2015 International Conference on Data Mining,* p. 37-43.

field across cable sections. They require a lead sleeve for the cable section to maintain the insulation properties of PILC cable. This is to hold the oil from oil-impregnated paper and protect insulation as much as possible. If these sleeves are compromised, this can result in drying out of the impregnated paper and compromise the insulation properties. Furthermore, as cable sections age, they begin to experience thermal, environmental, or mechanical stresses. Since XLPE and lead cables have different properties, the transition joint on any given feeder experiences the most stress. For example, the Windsor TS feeder A-93-WR supplies 7 large customers, and includes 5 transition splices and 7 lead joints, as shown in Figure 3 below. Failure at any of these splices or joints will result in an outage while crews switch customers to backup supply, which typically takes 2 to 4 hours and subsequently about 8 to 10 hours until full power is restored.



Capacity of Feeder	9.7 MVA
Feeder Reading (Actual reading)	8.4 MVA*
N-1 Contingency (Load if A-94-WR is de-energized)	11.6 MVA*

*Based on a non-coincident peak loading condition

Figure 3: Schematic Feeder A-93-WR that depicts Transitional and Joint Splices

Figure 4 below illustrates examples of splices with deficiencies.

Figure 4: Sample PILC Joint with a Split Sleeve, i.e. Leaker (Left) and Collapsed Cable Splice (Right)

In addition to increased failure risk due to cable splicing, there is the risk of oil leakage from the insulation on PILC cables. Over time, due to load fluctuations and physical stresses on feeder cables, the outer covers of lead cables develop cracks, causing oil from the paper insulation to leak from the cable and pool on the cable chamber floor. On average, Toronto Hydro finds 8 such leaks per year.

As shown in Figure 5 below, the failure rate of lead splices and transition joints per kilometre increases with the age of the feeder sections, i.e. the older the feeder, the higher the number of outages. The majority of these failures are due to moisture ingress, reduction in dielectric strength due to oil leaking from cracks and pinholes, as well as thermal stress.

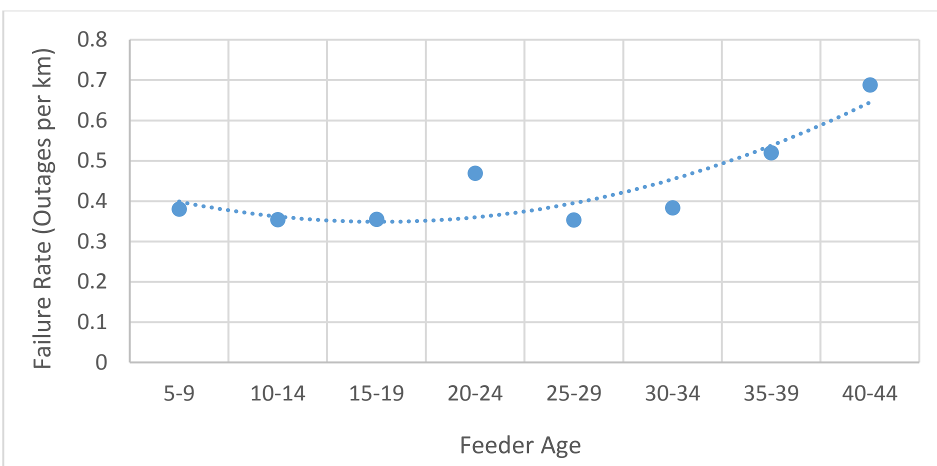
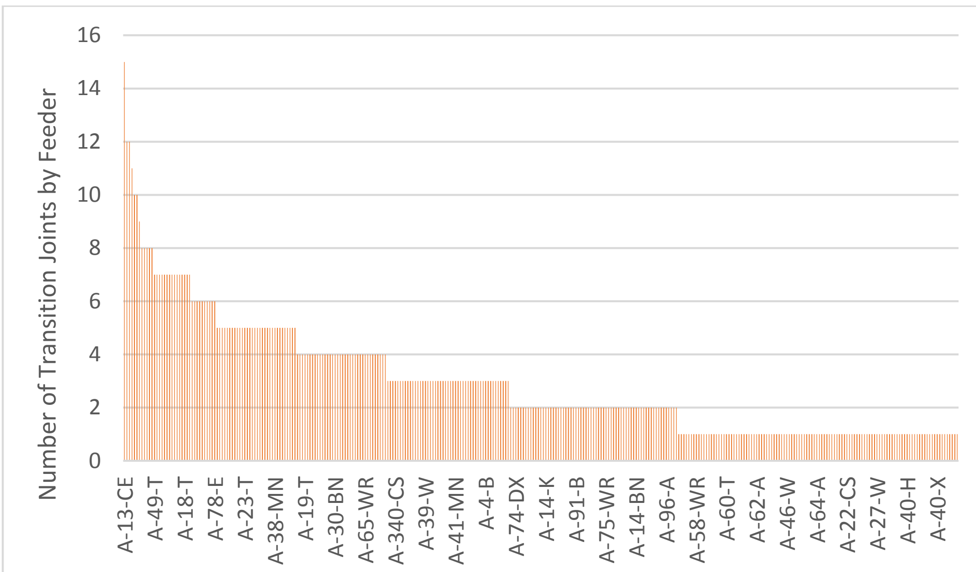


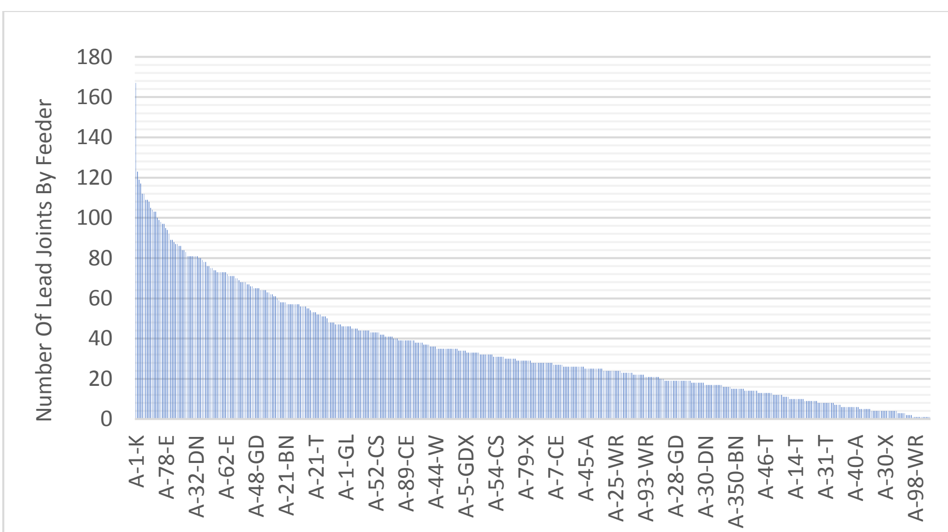
Figure 5: Failure rate of cable splices with PILC[10]

[10] It is important to note that Toronto Hydro keeps a limited quantity of PILC cables on hand for extreme circumstances where reactive repair is required.

1 On average, there are 6 transition joints and 40 lead joints per primary feeder in downtown Toronto.
2 By the end of 2024, given the PILC cable planned for replacement, Toronto Hydro expects to reduce
3 the average number of transition joints to 4 and lead joints to 30. Figure 6 and Figure 7 illustrate the
4 current state of transition joints and lead joints in the system on feeders (though not all feeders are
5 labelled therein).



6 **Figure 6: Transition Joints by Feeder**



7 **Figure 7: Lead Joints by Feeder**

As shown in Figure 8, there are on average 26 reported PILC cable or splice related failures per year, including on average 14 failures per year related to splices.

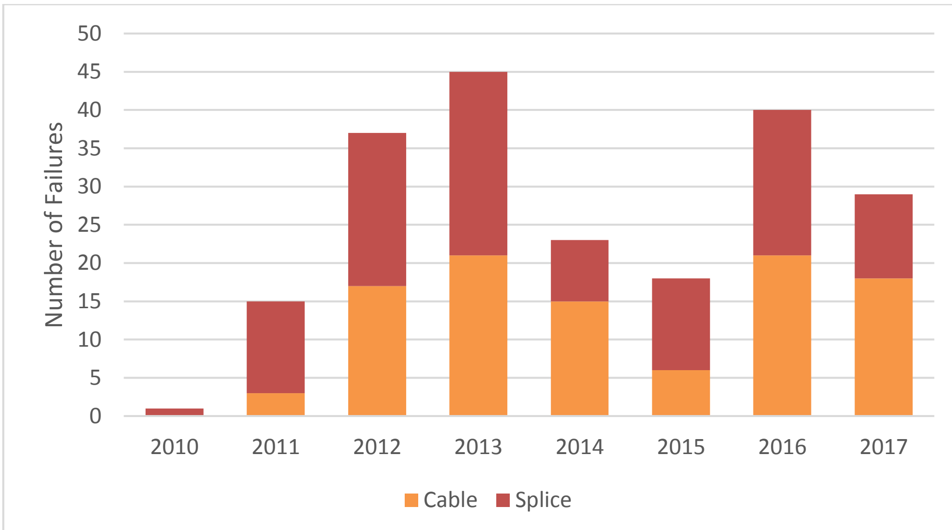


Figure 8: Number of PILC Cable/Splice Failures per Year

Based on the reported 208 cable and cable splice related incidents between 2010 and 2016, there is a clear relationship between age and failure per km. As per Figure 5, the number of failures per km rises with cable age. Quantitatively, this trend aligns with the qualitative observation by field personnel of the rise of failures as more splices are introduced while cable sections age.

Cable failures affect a wide range of customers, whose configuration of connection to the system depends on the feeder and the supply location and not necessarily customer type. Figure 9 below illustrates this using seven sample feeders. This segment aims to target feeders with large loads like the A-93-WR, and introduce uniformity of cable by proactively replacing a large section of cable especially in the downtown core. This aligns with the customer engagement results where downtown customers (especially large customers) prioritize reliability over price. Large multi-residential buildings are treated as large commercial customers since minimal cable renewal investments will impact many end use customers.

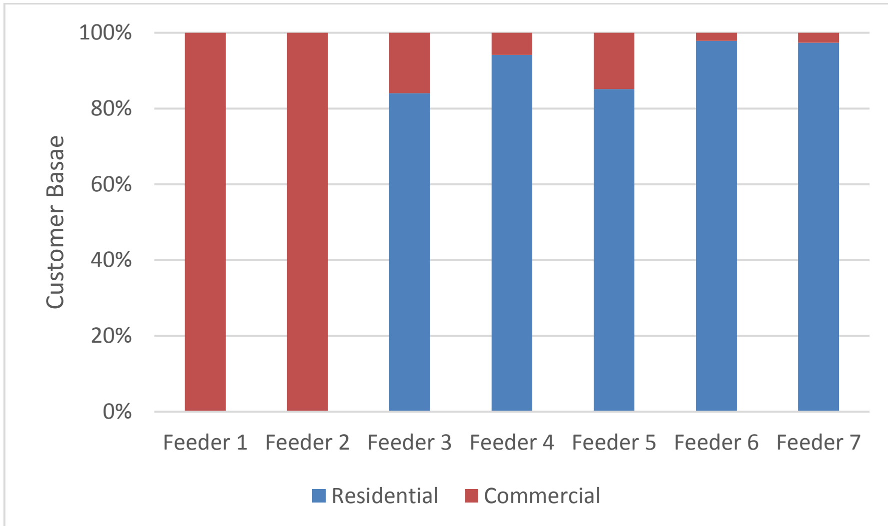


Figure 9: Composition of Customer Type of Circuits with PILC Cable

Lead-based cables (e.g. AILC and PILC) also need to be removed from the system due to a large functional obsolescence component. Lead splicing typically requires highly qualified and trained individuals. Many utilities are facing the challenge to train personnel with respect to lead splicing techniques. The skillset in the workforce is diminishing as lead cable is not actively introduced into the system. Furthermore, PILC cable is only supplied by one North American manufacturer at this time and a procurement problem may arise in the near future, while AILC cables are currently obsolete and are no longer supported by any manufacturers. Although Toronto Hydro stocks minimal PILC cable, it is not actively introduced into the system. Rather, polymeric XLPE and TRXLPE cables are used. As noted above, this increases failure risk if these non-homogenous feeder types are not minimized.

These cables present both safety and environmental risks. Lead is a designated substance as per Ontario Regulation 490/09 (see section 10) and exposure should be minimized to mitigate the health risks. The risks of working with this substance alone is a potential safety hazard as lead needs to be exposed to high temperatures to complete a lead splice. This can create airborne fumes increasing the occupational, and environmental exposure. Further, PILC cables manufactured prior to 1986 may contain PCBs within the oil. Toronto Hydro is committed to mitigating the risks of oil leaks containing PCBs. Leaking PILC cables also present risks to crew and public safety as the likelihood of arc flashes due to the deterioration of the insulation is high. Arc flashes are dangerous to crews and pose a safety risk to the public if leaking oil becomes ignited. Leaking oil is a sign of pending cable failure.

E6.3.3.2 Cable Chamber Renewal

The Cable Chamber Renewal segment will invest in the structural integrity of Toronto Hydro's aging population of cable chambers by rebuilding or abandoning HI4 and HI5 condition chambers. Cable chambers house, protect, and provide access to underground electrical equipment across the city. There are 10,655 cable chambers in Toronto Hydro's underground distribution system of which approximately 80 percent are in the downtown area. These chambers hold up to 29 circuits each, supplying anywhere from 3,500 customers of different types and sizes, down to a few large industrial or commercial customers (e.g. financial institutions, hospitals).

Cable chambers have a useful life of 65 years, while chamber roofs have a useful life of 25 years, meaning that the roof will require a rebuild at least once during the useful life of the chamber. Figure 10 shows the remaining useful life, as of 2017, for all cable chambers and roofs. Approximately 2,400 chambers and 6,800 chamber roofs will be at, or beyond, their useful lives by 2024.

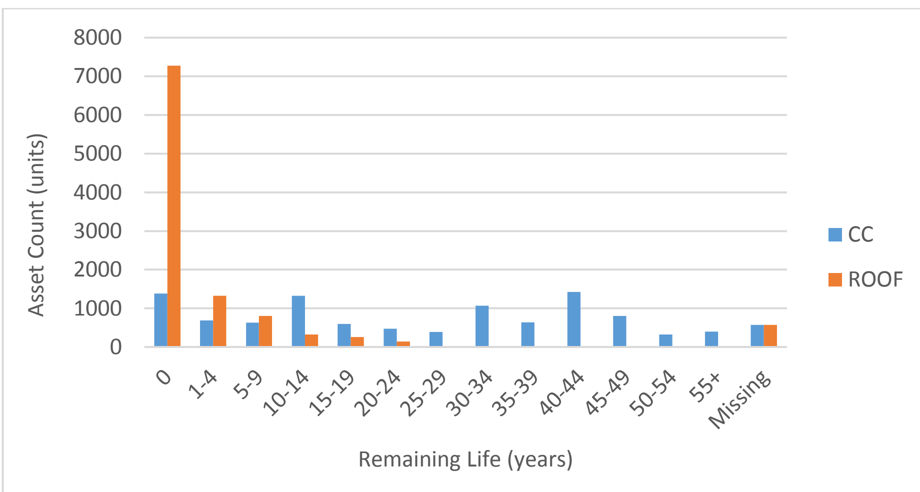


Figure 10: Remaining Useful Life of Cable Chambers (CC) and Roofs

Toronto Hydro inspects cable chambers and cable chambers roofs on a planned 10-year cycle. The growing backlog of aging cable chambers is reflected in the observed condition of the assets. Figure 11 below shows the asset condition of the 10,665 cable chambers in Toronto Hydro's distribution system as of 2017. The data indicates that 507 cable chambers have conditions classified as HI5 or HI4 and will require rebuild in the near-term. Furthermore, inspection data indicates that an additional 102 cable chamber roofs are in HI4 condition.

Depending on the severity of issues, Toronto Hydro ensures the time of rebuild is determined based on a holistic review of the structural condition of the chamber (even if classified as HI5). This means a cable chamber may require a reactive rebuild or temporary repairs to mitigate safety risks which would allow for a planned rebuild in the future.

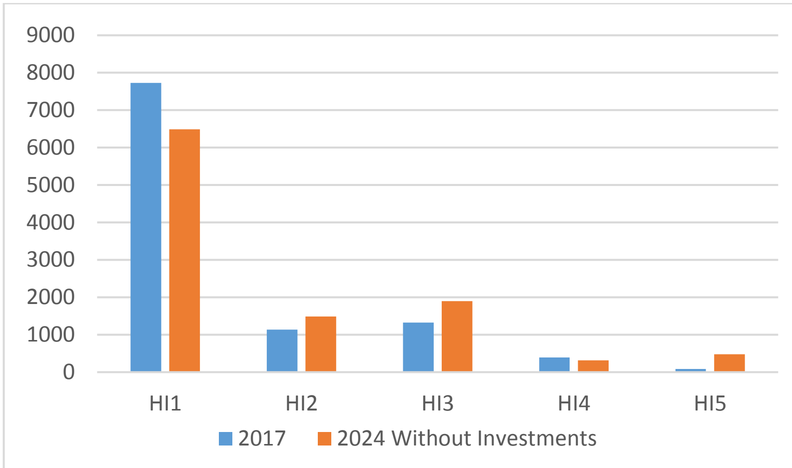


Figure 11: Projected Cable Chamber Asset Condition as of 2020 and 2024 without Investment

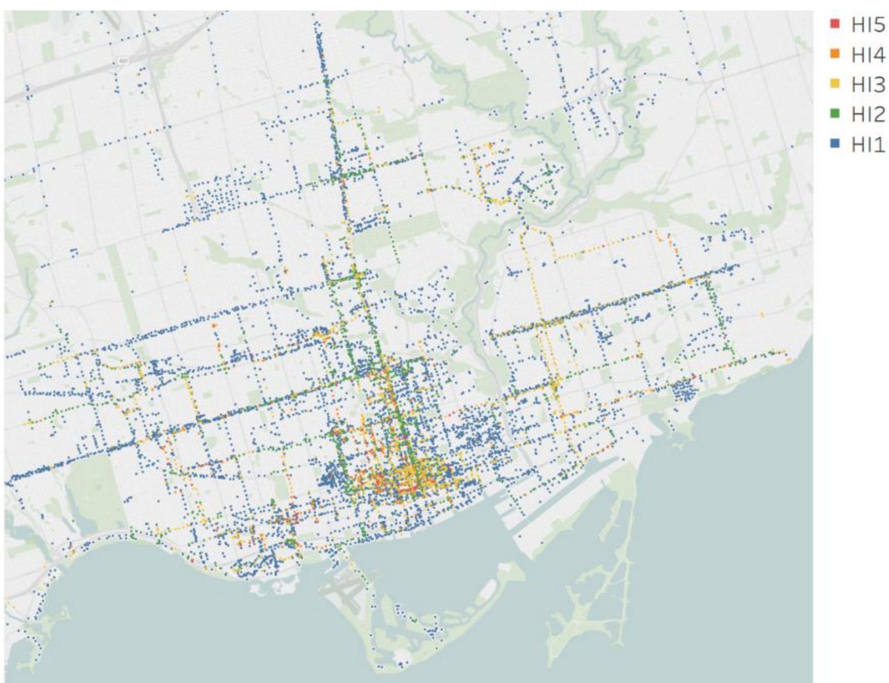


Figure 12: Cable Chamber Locations and Conditions

Figure 12 above shows the high concentration of HI4 and HI5 condition chambers in the downtown core, where, as mentioned above, the chambers tend to carry a high concentration of circuits serving thousands of customers, or large customer loads. Should a chamber or chamber roof collapse to any extent, the equipment in the chamber could be damaged, leading to a potentially lengthy outage for the aforementioned customers.

Of equal or greater concern is the risk to crew and public safety posed by a failing cable chamber. In areas of high vehicular or foot-traffic especially, a structurally unsound chamber or roof can create hazards to the public. The collapse of a chamber or chamber roof could have more severe consequences for the public or for crews working in the chamber. Figure 13 below shows an example of a severely deteriorated cable chamber roof.

Figure 13: Cable Chamber Roof in HI5 Condition (Left), and Cable Chamber Roof Inside View (Right)

The images shown in Figure 13 are an example of a cable chamber with a reduced neck which is common when the City rebuilds or regrades roads. In this situation, when the asphalt was removed, a hole was discovered. This is very dangerous especially if the hole or deteriorated structure is covered by newly paved road.

Depending on the specific site, addressing a HI4 or HI5 condition chamber will include:

- **Full rebuild:** rebuilding the cable chamber civil structure, including its roof and duct banks, and involves some cable replacement; or
- **Roof rebuild:** rebuilding only the roof.

In addition to rebuilds, Toronto Hydro also plans to continue proactively replacing potentially hazardous cable chambers lids. Deteriorated cables running through cable chambers can become hot, potentially causing arcing and igniting gases which then can create a powerful shock wave. These shock waves can dislodge a chamber lid in a violent manner, ejecting it into the air and creating a serious public safety hazard. To date, Toronto Hydro has recorded 43 incidents related to cable chamber lids. As previously proposed in Toronto Hydro's 2015-2019 rate application,[11] the utility planned to replace lids on cable chambers to mitigate ejection risks. The plan was for new ejection-proof lids to become a standard based on trial installations in 2015. After the trials, modifications were required. Nevertheless, Toronto Hydro plans to install only 252 cable chambers lids by the end of 2019. Going forward, Toronto Hydro expects to replace 200 cable chamber lids per year and aims to replace all cable chamber lids that have a potential for lid ejection.

Toronto Hydro plans to replace all cable chamber lids proactively with a new energy mitigating design that will reduce the likelihood that a cable failure or other event within the chamber will cause the lid to become violently dislodged (thus placing the public at risk).

E6.3.3.3 Underground Residential Distribution Renewal ("URD")

This segment aims to replaces end-of-life and obsolete URD assets that contribute to the deterioration of system reliability. These assets include: vaults, switches, and transformers that form part of the URD system. Toronto Hydro plans to invest to maintain reliability performance. As per Toronto Hydro's customer engagement results, residential customers prioritize cost over reliability and therefore, only specific areas of the URD system are targeted for renewal in this segment rather than addressing the system as a whole.

Introduced in the 1990s, the URD system was intended to replace the 4 kV overhead system supplying residential customers in the downtown area. The URD system comprises of redundancies via main loops and sub loops to add a level of robustness by isolating sections of the feeder (see section D2 of the DSP for a more detailed overview of the URD system).[12]

To date, Toronto Hydro has managed the replacement of switches, transformers, and roof repairs on a reactive basis. However, due to the growing number of failing URD vault roofs, severe corrosion and obsolete equipment, Toronto Hydro is introducing a planned renewal segment in 2020. Since

[11] EB-2014-0116 Application, Exhibit 2B, Section E6.3, p. 16.
[12] Exhibit 2B, Section D2.2.2

2010, Toronto has reactively performed close to 4,000 work orders to repair or replace assets tied to the URD system. Figure 14, Figure 15 and Figure 16 below show the work orders issued for URD vault repairs and rebuilds, as well as transformer and switch repairs and replacements since 2010. As seen in Figure 14, Toronto Hydro has recently seen a rapid increase in work orders for URD vault civil repair and rebuilds compared to 2014 and 2015. In the past, most work orders issued addressed URD vault condition repairs. However in 2017, there was an increase in work orders that require URD vault roof rebuilds. As the URD vault roof approaches its end-of-life, an increase in work orders for URD vault roof rebuild is expected.

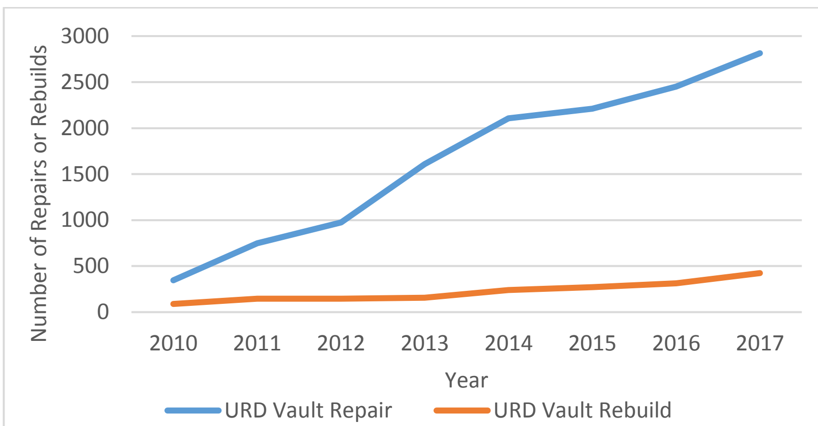


Figure 14: URD vault civil repair and rebuild

Figure 15 shows that for URD transformer replacement, Toronto Hydro has seen an average increase of 10 work orders per year for reactive transformer replacement.

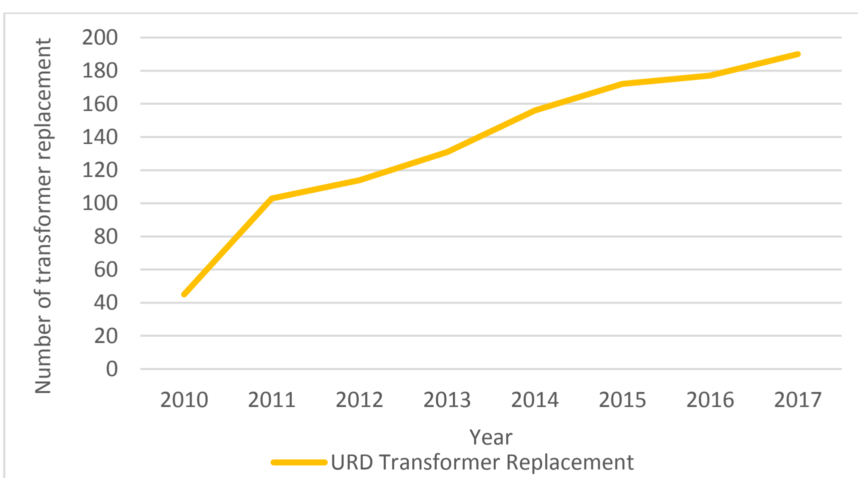


Figure 15: URD transformer repair and replacement

As for URD switch replacement, Toronto Hydro has seen an increase in URD switch replacements between 2010 and 2017 as shown in Figure 16.

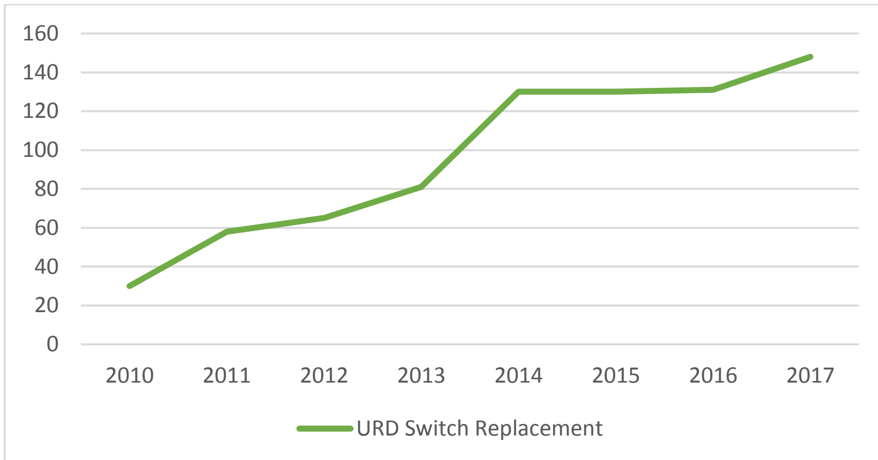


Figure 16: URD switch replacement

The main underground system configurations are either radial or looped. However, system types and configurations are sometimes mixed to provide better reliability or flexibility when repairs are required, as is the case with URD. In the URD system, primary cables, switches, and distribution transformers are placed underground while most secondary voltage connections remain overhead. This system only appears in limited areas throughout the pre-amalgamation City of Toronto, as seen in Figure 17 below.

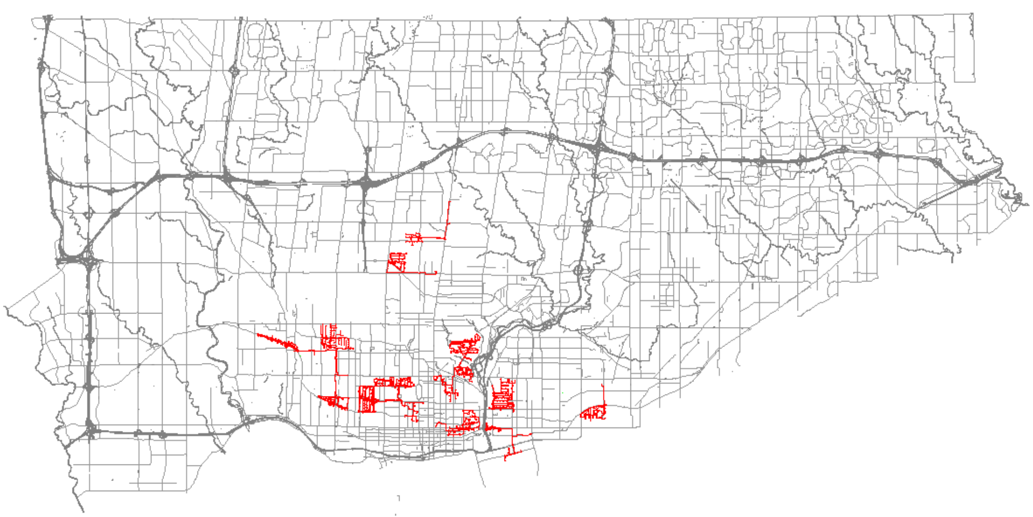


Figure 17: Map of Toronto with URD feeders

The URD has three distinct feeder sections: (i) a main-loop; (ii) sub-loops; and (iii) branch circuits (or sub-sub-loops). The main loop does not serve any customers but is equipped with multiple 600 A switching vaults that allow for the isolation of the sub-loops and branch circuits in the event of a fault. Customers are supplied directly from either the sub-loops or branch circuits, which allows partitions within the feeder to minimize interruptions if work is required. Figure 18 below provides a simplified example of the configuration of a downtown URD feeder.

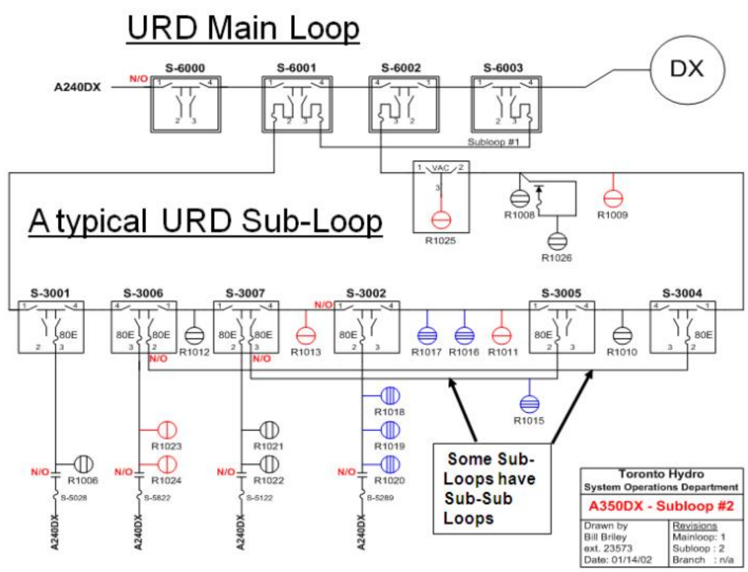


Figure 18: Typical URD Feeder Configuration

The URD installation began in early 1990's for 4 kV to 13.8 kV conversion projects and included a total of 150 normal feeders and 24 standby feeders. As of 2017, there are a total of 25 (normal and standby) 13.8 kV feeders and the majority of the equipment is approaching 25 years. However, due to the nature of costs incurred in rebuilding existing systems into a URD configuration, the URD program was discontinued post-amalgamation (in the early 2000s), thus reducing the planned work of 150 feeders to 25 feeders actually built. Table 5 below shows the total number of assets in Toronto Hydro's URD system.

Table 5: URD Asset Count

Asset Type	Total Number of Assets
Submersible Switches (200A & 600A)	146
Transformers	639
Vaults (Transformers and Switching)	592

In the last 4 years, URD system outages have increased, with an average of 2000 CIs and 7500 CHIs per year. Figure 19 below shows URD system outage statistics between 2010 and 2017.

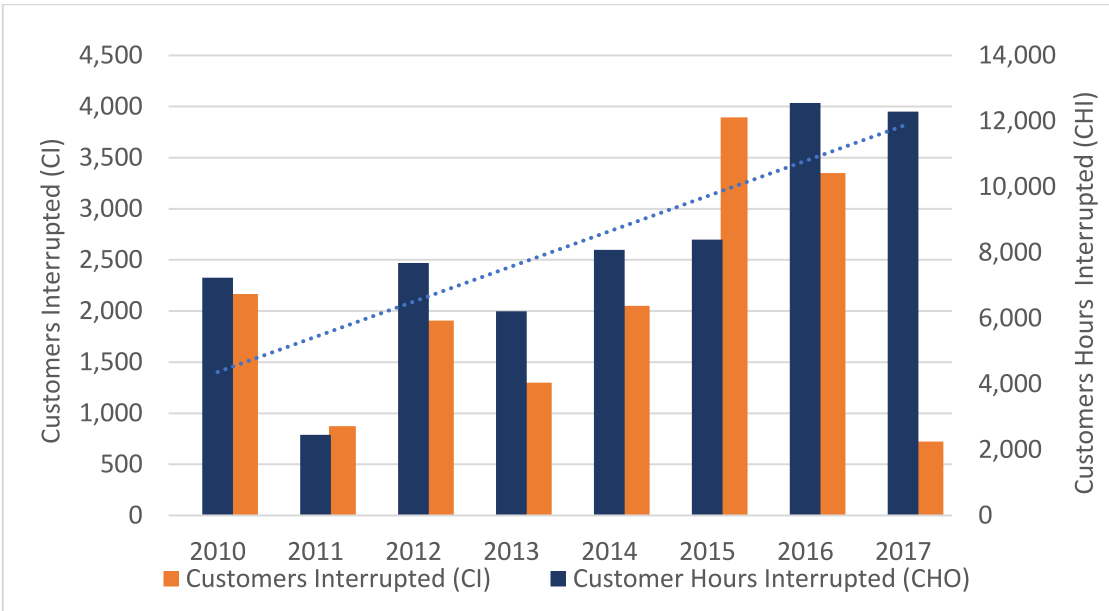


Figure 19: 2010-2017 URD System Outage Statistics

Maintenance and inspection of the URD vaults are performed twice a year, one inspection for the civil condition and the other for the electrical condition. As part of this work, the vaults are inspected to ensure the integrity of the electrical equipment, structure, and security. This includes a thermograph of all electrical assets, cleaning the entire vault and reporting any vaults that require follow-up repairs. The results of the inspections show that URD switching vault equipment is in a poor condition due to rust on the cabinet and corrosion on the connectors. Figure 20 and Figure 21 below provide the URD electrical and civil inspections results, highlighting the most common types of deficiencies identified and found over the past five years (i.e. 2013 to 2017).

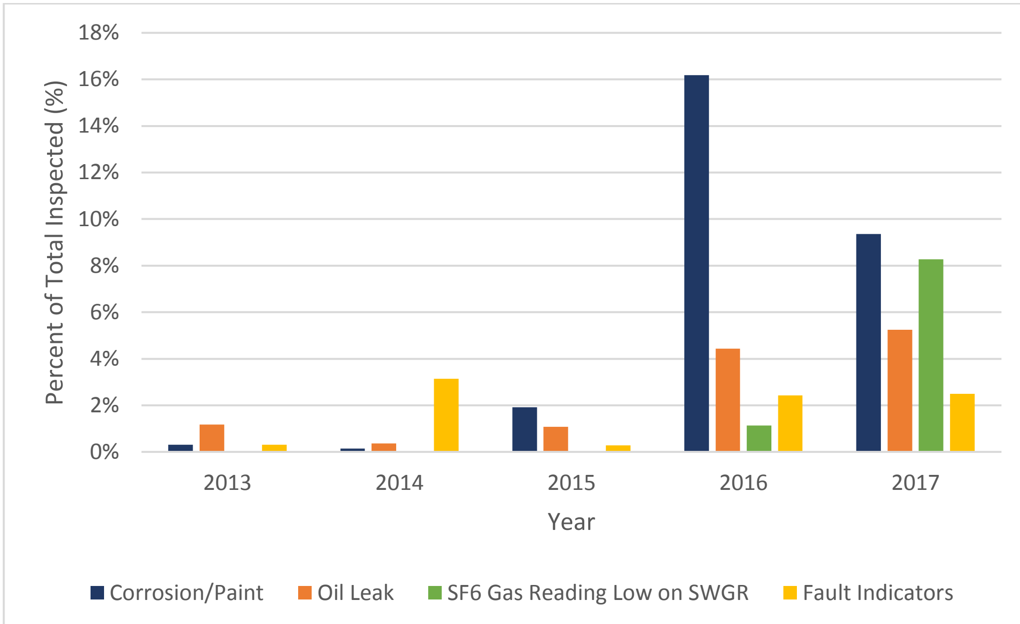


Figure 20: URD Electrical Deficiencies

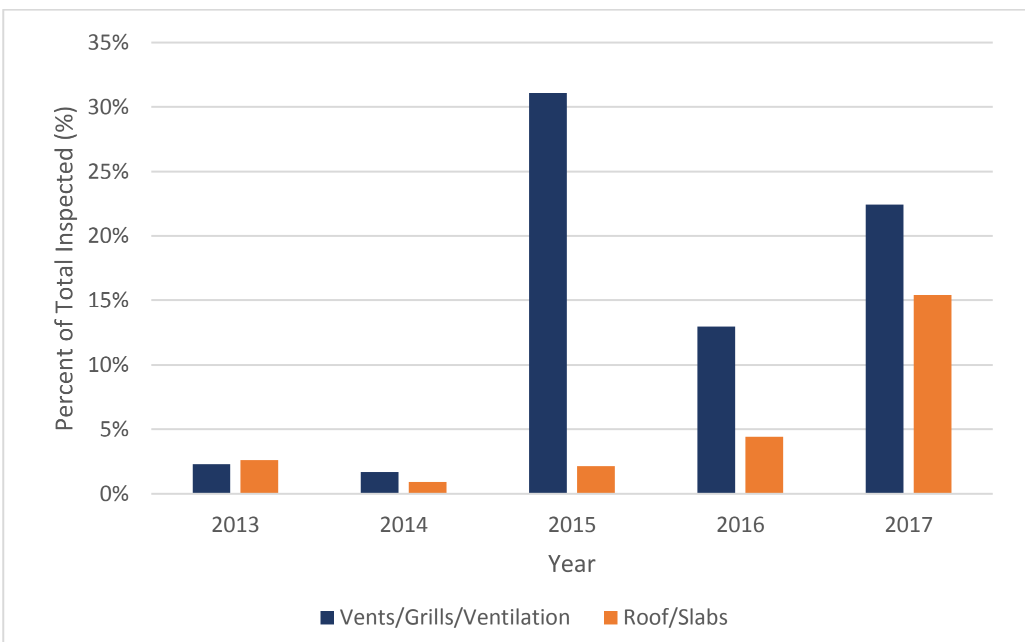


Figure 21: URD Civil Deficiencies

As per the URD electrical inspection data in Figure 20, the main issues are the recent rising incidents of deficient switch gear with low readings and faulty fault indicators, as well as corrosion of electrical equipment. Consequently, as per the civil inspection data in Figure 21, deficient switch gear due to vents/grills/ventilation and roof/slabs have been steadily increasing from previous years. These deficiencies increase the risk of failure of URD assets and as a result, the renewal process is driven by failure risk. The following sections describe the state of two main assets of the URD system: URD vault roofs and URD switches (including fault indicators) while considering the above mentioned deficiencies.

1. URD Vault roof

Civil conditions of URDs deteriorate over time due to exposure to harsh environments as a result of severe weather, salt, or road construction. Some commonly found structural deficiencies caused by asset aging and environmental factors are exposed roof and wall rebar, corroded I-beams and cracked roof and walls. Such deterioration includes corrosion, spalling of concrete, and cover rusting which pose a potential safety hazard for the public and field crews. Compounding this situation, the ventilation design and equipment layout inside the vault have allowed dirt to accumulate on top of switching equipment, causing corrosion of components such as elbow terminations. This degradation of the URD system increases the failure risk of the assets within it. Illustrative examples of the aforementioned types of roof cracks are shown in Figure 22 and Figure 23 below.

Figure 22: URD Vault with Deficient Roof

Figure 23: URD Vault Deficient Roof Temporarily Repaired with Asphalt

The useful life of a URD vault is 60 years while the roof is 25 years. Therefore, the roof is typically rebuilt at least once or twice during the life of the vault. The current roofs of the URD vaults have reached or passed their useful life, and as such are considered for rebuild. The inspection data (as shown in Figure 21) demonstrates that an increasing number of URD vault roofs are being identified as having some level of roof deficiency.

Given the deficiencies being identified, Toronto Hydro is developing a new roof design that minimizes the amount of dirt, debris, and water that accumulate directly on electrical equipment. The new design will be similar to the compact radial distribution ("CRD") underground vault, which typically supply small retail, apartment, and commercial office buildings. In addition, the new design will improve safety by reducing the potential of tripping incidents, and create a larger opening for the replacement of electrical equipment. When rebuilding a vault roof, the electrical equipment will be assessed and upgraded to the latest standards if existing equipment is in poor condition or obsolete. In situations where the electrical equipment is in good condition, it will remain in-service.

2. URD Switches

Switches used in URD are submersible, 200A and 600A, SF_6-insulated switches which are operable from above grade. SF_6 load break switches are designed and constructed to provide safe and reliable switching. Using SF_6 for insulation and arc interruption eliminates space, weight and maintenance costs. The switch provides improved interrupting and open gap performance, while at the same time eliminating most hazards associated with vacuum or oil filled equipment. In the URD system, the switches are mounted on stands close to the vault wall for ease of operation, cabling, and space utilization.

As of the end of 2017, these switches are deteriorating in condition. A large portion does not have stainless steel enclosures and are experiencing gas leakage problem inherent to the former design of the bolted viewing window, as shown in Figure 24 below.

Figure 24: Example of a SF_6 Switch with a “Low” Reading

Due to the design and equipment specification of URD 200A and 600A switching vaults, they do not contain an available heat source, such as a transformer, that would promote air circulation. As a result, non-stainless steel switching equipment installed in those vaults are experiencing accelerated corrosion due to exposure to stagnant moisture. Compounding this situation, the ventilation design and equipment layout inside the vault have allowed dirt to accumulate on top of switching equipment, causing corrosion of components such as elbow terminations and supports or support beams. An example of a corroded support beam can be seen in Figure 25.

Figure 25: Example of Switch Supports that have rusted

The 200A SF6 switches are used to switch load as part of the subloop system. They also support 80E SF6 power fuses, which are used for the protection of branch circuits in the URD and are no longer manufactured. (Only 41 remain in Toronto Hydro inventory.) A picture of the 80E Fault Fiter fuse is provided in Figure 26. In this regard, the switches are functionally obsolete, as they are no longer supported by the original manufacturer and no spare parts are manufactured or available. Replacement of both the fuse and switchgear is required to provide the adequate protection for branch circuits.

Figure 26: 80E Fault Fiter Fuse

As the URD vaults, transformers, and switches approach the end of their useful life, related equipment and civil infrastructure need to be updated to mitigate failure risk. The roof vaults will be replaced with a newer design that reduces the dirt, debris and water entering the vaults, improves safety by reducing tripping incidents and creates a larger opening for replacing old switches. Along with roof rebuilds, electrical equipment such as transformers or switches within the vault will be replaced with the equivalent latest standard. Switches will be replaced with the new generation of SF_6-insulated switches which have stainless steel enclosure to prevent premature rusting and degradation of the cabinet.

E6.3.4 Expenditure Plan

To address the needs of the underground assets in downtown Toronto, Toronto Hydro plans to invest $122.0 million over the 2020-2024 period. Each segment entails a unique investment strategy. As this Program is replacing the Piece-Out and Leakers program (see section E4 for details), it is considered as a new program with no historical costs.

Table 6: Forecast Program Costs ($ Millions)[13]

Segments	Forecast				
	2020	2021	2022	2023	2024
Underground Cable	8.9	16.2	17.3	23.4	23.9
Cable Chamber	5.6	5.7	5.8	5.9	6.1
Underground Residential Distribution ("URD")	0.6	0.6	0.7	0.7	0.6
Total	**15.1**	**22.5**	**23.9**	**30.0**	**30.6**

E6.3.4.1 Underground Cable Renewal

Table 7: Underground Cable Renewal 2020-2024 Program Costs ($ Millions)

	2020	2021	2022	2023	2024	Total
Underground Cable	8.9	16.2	17.3	23.4	23.9	**89.7**

Table 8: 2020-2024 Volumes (Forecast): Underground Cable Renewal

Asset Class		2020	2021	2022	2023	2024	Total
PILC Cable	*km*	2.9	5.1	5.3	7.1	7.1	**27.4**
AILC Cable	*km*	5.6	9.9	10.4	13.8	13.8	**53.3**

/C

[13] Note that costs associated with former streetlighting assets are embedded in the costs of the segments.

The Underground System Renewal – Downtown program prioritizes at risk cable segments based on historical failures, number of splices on feeders, age and customer base. This will be used in conjunction with complementary cable testing data to validate the volume of cable replacement required. This is considered to be a best practice in the industry and is used by utilities such as Consolidated Edison (ConEd) in New York City for their PILC cable replacement program.[14] Studies have shown that this method is driven by condition and is a reliable alternative to traditional methods for asset ranking.[15]

Toronto Hydro has determined that approximately 2.5 percent of the PILC population is in a critical state and should be addressed through proactive replacement during the 2020-2024 period. This 2.5 percent amounts to 27 circuit-kilometres of PILC, and will trigger replacement of 24 percent of the existing AILC population (53 circuit-kilometres) connected downstream of PILC cable. /C

Based on similar past work, Toronto Hydro estimates that PILC cable replacement projects will cost, on average, approximately $1.8 million per circuit-km, while AILC replacement will cost approximately $0.5 million per circuit-km. Toronto Hydro has applied these volumetric costs to the forecast population of critical cables to develop the 2020-2024 segment cost of $63 million.

E6.3.4.2 Cable Chamber Renewal

Table 9: Cable Chamber Renewal 2020-2024 Program Costs ($ Millions)

	2020	2021	2022	2023	2024	Total
Cable Chamber	5.6	5.7	5.8	5.9	6.1	**29.1**

Table 10: 2020-2024 Volumes (Forecast): Cable Chamber Renewal

Asset Class	2020	2021	2022	2023	2024
Cable Chamber	15	15	15	15	15
Cable Chamber Roof	24	24	24	24	24
Cable Chamber Abandonment	3	3	3	3	3
Cable Chamber Lid	200	200	200	200	200

[14] M. Olearczyk et. al., *Notes from Underground – Cable Fleet Management*, Nov. 2010. Available at <http://www.neetrac.gatech.edu/publications/Note_from_Underground_Nov2010.pdf>.
[15] M. Buhari, V. Levi and S. K. E. Awadallah, "Modelling of Ageing Distribution Cable for Replacement Planning," in *IEEE Transactions on Power Systems*, vol. 31, no. 5, pp. 3996-4004, Sept. 2016.

Reconstructing a cable chamber requires breaking into or reconstructing portions of ductbank. As such, the cable chamber renewal segment includes the cost of reconstructing a portion of a duct bank along with the cable chamber. Required electrical work within a cable chamber, road or sidewalk repair or road restoration are also incorporated into the cost. Toronto Hydro's spending plan for this segment is approximately $5.9 million per year for the 2020-2024 period, including, on an annual basis: (i) cable chamber lid replacement for $1.6 million per year ($8,000 per unit), and (ii) 22 cable chamber rebuilds ($170,000 a unit), 24 cable chamber roof rebuilds ($20,000 a unit) and 3 cable chamber abandonments ($20,000 a unit), all at a total cost of $4.3 million on average per year.

In developing the cable chamber renewal segment, Toronto Hydro assumes outages are not required for cable chamber rebuilds. This means cables are tied together and are safely out-of-the-way when rebuilds occur. As a result, cable chambers are mainly prioritized based on the condition of the civil infrastructure as well as the types of customers and thermal loading of feeders.

Based on inspection records, 204 cable chambers and 102 roofs have been identified to be in HI4 and HI5 condition. Since cable chamber renewal is new, Toronto Hydro is planning a small number of rebuilds for the 2020-2024 Program to address chambers that are in HI5 and HI4 condition. It is important to tackle cable chambers with structural failure issues and diligently rebuild a set number of cable chambers every year.

E6.3.4.3 URD Renewal

Table 11: URD Renewal 2020-2024 Program Costs ($ Millions)

	2020	2021	2022	2023	2024	Total
URD	0.6	0.6	0.7	0.7	0.6	**3.2**

Table 12: 2020-2024 Volumes (Forecast): URD Renewal

Asset Class	2020	2021	2022	2023	2024
URD Submersible Switches	3	3	3	4	4
URD Transformers	1	1	1	0	0
URD Vault Roof	3	3	4	4	4

URD renewal segment is a new segment to be carried out in the 2020-2024 period. Currently, severely deteriorated URD roof rebuilds and switch or transformer replacements are handled on a reactive basis. As structures and equipment age, the number of rebuilds required will only increase.

Planned rebuilds are preferred to reactive rebuilds for URD assets that require various resources and co-ordination.

As part of the URD system renewal program, Toronto Hydro will prioritize projects based on the condition of civil roofs as deficient roofs pose an immediate risk to the public. Where civil roofs are considered deteriorating, assets such as URD switches and transformers within these vaults will be replaced on an as-needed basis according to inspection records. Where the civil assets are in good condition and the electrical assets are not, such locations will be assigned a lower priority.

As this is a new program, Toronto Hydro has estimated the completion of three roof rebuilds and switch replacements per year for the first three years. As it develops experience in performing this work, Toronto Hydro would increase the number by one for the remaining years of the Program. In total, Toronto Hydro aims to complete 18 roof rebuilds, 18 switch replacements, and 3 transformer replacements in the 2020-2024 period.

E6.3.5 Options Analysis

E6.3.5.1 Underground Cable Renewal

1. Option 1: Reactive Replacement Approach

In this option, Toronto Hydro will allow all cables to operate under a reactive replacement scenario. Therefore, cables will be replaced under the Reactive and Corrective Capital program.

As mentioned in section 3.1, PILC and AILC cables are becoming obsolete across the industry due to environmental, health, and safety concerns. PILC and AILC cables were initially installed in the downtown system due to their high reliability and long life span. There are approximately 1,100 circuit-kilometres of 13.8 kV PILC underground cable on the system and approximately 42 percent of all PILC cables and 68 percent of all AILC cables in the system are more than 20 years old. These aged cables are showing signs of deterioration, including pin holes, cracks, and leaks. If these cables are allowed to deteriorate, reliability and safety risks will persist and increase as a result of the increasing number and duration of outages in the distribution system.

Therefore, under this option, when PILC and AILC cables fail, Toronto Hydro will splice XLPE cable into sections of PILC and AILC cable to maintain long cable sections. As a result, this will further increase the risk of failure by increasing the percentage of non-uniform cable in the system. These splices create and add weak points along the cable, introducing additional failure risk to already aging cables that serve many large and critical loads. Consequently, feeder life expectancy and probability of failure worsen drastically. This will negatively impact customer service in the downtown area. The status quo option would not be prudent as it does not address the needs of downtown customers that prioritize reliability over price.

Additionally, when a cable can no longer be maintained through splicing, Toronto Hydro will replace the cable. The costs of replacing a cable reactively is also higher than proactive replacement. Toronto Hydro estimates that replacing all cables reactively could vary considerably, but average out to approximately 10 percent more than the costs allocated to the preferred option (discussed below). Reactive work is especially challenging in the downtown area due to considerable coordination with third parties that is required. Therefore, Toronto Hydro does not recommend pursuing this option.

2. Option 2 (Selected Option): Targeted Replacement of PILC and AILC Cables

Toronto Hydro is planning to remove approximately 24 percent of AILC cable (53 circuit kilometres of 220 kilometres) and 2.5 percent of PILC cable (27 circuit kilometres of 1,100 kilometres) between /C 2020 and 2024. The cables will be replaced based on the risk level associated with the cable segment. This proposed pace is a particularly conservative pace given that it will take approximately 200 years to renew the existing PILC in Toronto Hydro’s distribution system. As a result, the utility expects to increase the pace of this segment following the 2020-2024 period.

In addition, as primary cables and cable segments are being tested or replaced, Toronto Hydro will re-prioritize at-risk feeders. Where at-risk primary cable sections are identified, this will drive the replacement of the legacy type AILC cable that is connected downstream of these cable sections.

Under this option, Toronto Hydro would mitigate the failure risk on the downtown distribution system and increase reliability. As mentioned in section 3.1, and in Option 1 above, non-uniformity (i.e. cable splicing) increases the risk of failure. Therefore, by replacing the highest risk cables, the utility will increase the uniformity of cable types in the system (i.e. by replacing the non-uniform cable with XLPE cable), which will increase reliability on the system.

In addition to increasing reliability, this option will reduce the risk of oil leakage from the insulation on PILC cables and therefore, reduce the need for service interruptions on customers to address the leaks.

3. Option 3: Replacement of all PILC and AILC cable over 50 years

As noted under option 2, the proposed plan sets a slow pace for PILC renewal, projected to be 200 years. Under this option, Toronto Hydro would replace PILC and AILC cables in its distribution system. At a pace that achieves a 50-year total renewal period.

This would allow the utility to more assertively address the environmental and safety issues associated with the continued use of PILC and AILC cables. It would also mitigate the risks associated with a single supplier (i.e. procurement risk).

Furthermore, it would address reliability risks and provide downtown customers with enhance reliability.

However, this option is estimated to cost approximately four times the cost of the proposed plan. In addition to being costly, Toronto Hydro may not be able to allocate the required resources for this option in the 2020-2024 period.

E6.3.5.2 Cable Chamber Renewal

1. Option 1: Reactive Replacement Approach

Under the status quo, Toronto Hydro will rely on the Reactive and Corrective Capital program (Exhibit 2B, Section E6.7) to rebuild cable chambers that fail. Cable chamber deterioration is not visible from the surface as the structural elements are below grade.

The freeze-thaw cycle in winter combined with road salt accelerates the deterioration of concrete structures. The number of structures that will fall into 'emergency' category for rebuild is expected to increase to a point that it will be extremely hard to manage the situation through reactive response. The risk of lids lifting off can also be minimized by replacing them with energy mitigating lids.

The load from motor vehicle traffic (particularly heavy trucks) and the general public is another factor that causes the civil condition of the cable chamber to deteriorate over time. Compromised civil condition of cable chambers can eventually result in serious consequences, such as injuries or fatalities due to large pot holes.

In addition, cracked roof slabs can lead to potentially serious harms to Toronto Hydro crews while doing work in the chambers, as chunks of concrete can fall on workers.

Given the above risks, this option is not recommended.

2. Option 2 (Selected Option): Renew Cable Chambers

Toronto Hydro has to proactively engage in renewing its cable chamber population. This Program is therefore essential as a first step to reaching a goal of clearing all the backlog of deteriorated structures and prevent cable chambers from surpassing their useful life.

Cable chamber rebuilds are highly complex projects, as they require not only civil resources but also electrical resources, permits from the City to dig into streets, management of the high volume of downtown vehicular and pedestrian traffic, and extensive coordination between various stakeholders. The new chamber has to conform to current standards and the size may have to be enlarged to minimize congestion of the cables inside and to accommodate more cables for future needs. In light of these needs, a cable chamber rebuild requires a detailed design. If the cable chamber rebuild is done on a reactive basis, the lack of lead time means it will be hard to work within or comply with all of the above constraints. Therefore, planned rebuild as proposed in this Program is a superior option than rebuilding cable chambers reactively.

The preferred pace is moderate and accounts for resourcing considerations as well as the length of time civil deficiencies can be managed before renewal is required.

3. Option 3: Higher Pace Cable Chamber Renewal

With an incremental spend of approximately $22.3 million, Toronto Hydro would eliminate the risk of cable chamber lid ejections are locations identified as posing high and medium risks, and reconstruct all at risk cable chambers within 15 years as opposed to 30 years. Although appealing from an asset management perspective, this accelerated pace of would require significantly more resources and may not be cost-effectively accomplished over the 2020-2024 period.

Furthermore, road moratoriums within Toronto’s downtown core may further challenge Toronto Hydro’s ability to execute the work at an accelerated pace in the short- to medium-term. As a result, Toronto Hydro is not proposing this option.

E6.3.5.3 URD Renewal

1. Option 1: Reactive Replacement Approach

The useful life of a URD vault is 60 years while the roof is 25 years. Therefore, the roof is typically rebuilt at least once or twice during the life of the vault.

Under the status quo, Toronto Hydro will replace assets reactively once they fail. As such, Toronto would rebuild deficient URD roofs, replace defective URD switches and obsolete fuses that protect URD switches under the Reactive and Corrective Capital program (Exhibit 2B, Section E6.7). URD roof rebuilds are sometimes not visible from the surface as the structural elements are beneath the surface. The civil condition of the URD vault roof can also compromise the electrical equipment within the vault. This would also increase the safety risk for Toronto Hydro employees as crews sometimes enter a vault where a cracked roof slab is present. Chunks of concrete could potentially fall on to the workers and the equipment, giving rise to serious harm.

Under this option, Toronto Hydro expects an increase in failures and outages on the downtown underground distribution system, thus negatively impacting reliability. As identified in the needs section (section E6.3.3), a main cause of failures in switches is corrosion. Failure at the switches can lead to serious consequences causing interruptions to all customers the URD vault serves. Over the last 4 years, URD system work requests and outages have increased considerably, and given that the majority of vault roofs have or will be at or beyond useful life by 2020, managing the URD system on a reactive basis is not prudent.

2. Option 2: (Selected Option) Renew URD assets

Toronto Hydro has to proactively renew the roof of the URD vaults, replacing the 200A switch and other poor conditioned assets. As URD vaults, transformers and switches approach the end of their useful life, related equipment and civil infrastructure need to be updated to mitigate failure risk. It is therefore essential to prevent URD roof rebuilds before emergency rebuild is required.

The roof vaults will be replaced with a newer design that reduces the dirt, debris and water entering the vaults, improves safety by reducing tripping incidents and creates a larger opening for replacing old switches. Along with roof rebuilds, electrical equipment such as transformers or switches within the vault will be replaced with the equivalent latest standard. The 200A switches (which are no longer supported by the manufacturer) will be replaced with the new generation of SF6-insulated switches which have stainless steel enclosure to prevent premature rusting and degradation of the cabinet.

This will prevent a scenario where the utility may run out of fuses in its inventory (which are no longer manufactured).

This proactive replacement strategy will allow Toronto Hydro to assess the deficient URD assets and devise optimal planning strategies for the future of the URD system.

Under this option, Toronto Hydro would maintain and in some instances improve reliability in downtown areas.

3. Option 3: Renew URD assets and replace all URD switches

Under this option, Toronto Hydro would replace a larger population (75 percent) of the obsolete 600A switches between 2020 and 2024 compared to the preferred option as well as renew a larger quantity of URD assets.

Relative to the chosen option, this approach will cost approximately 40 percent more and is therefore not an economically preferable alternative, given that the URD system serves residential load and residential customers prioritize cost over reliability.

E6.3.6 Execution Risks & Mitigation

A key execution risk affecting the Underground System Renewal – Downtown program is external dependencies. In the downtown area, coordination with third parties (e.g. City of Toronto, TTC) has been an on-going requirement. Toronto Hydro invests substantial efforts to ensure effective inter-agency coordination.

Toronto Hydro engineers will ensure optimal routes are chosen based on criteria, such as the avoidance of busy intersections, and paths where utilities reside. Often, projects would involve construction of new civil assets such as duct banks or cable chambers. It is expected that these projects may be delayed without effective coordination. To mitigate risks, these projects will be planned well in advance.

Additionally, road moratoriums have the potential to delay projects in the downtown core. To mitigate this risk, Toronto Hydro will plan and schedule work accordingly.

The Underground System Renewal – Downtown program will prioritize at-risk cables dynamically as testing data, and cable replacement data become available. This means cables that are deemed low-risk in one year, may be high risk in another year. As such, dynamic planning will be required by engineers and project managers, which is advantageous in targeting, based on best available information, only feeders that are statistically more likely to fail. On the other hand, this approach may result in disruptions to project scheduling and planning. Efforts will be made well in advance to coordinate multiple projects at the same time so projects are deferred or advanced accordingly.

Since all URD assets are located in residential neighbourhoods in the downtown core, coordination with the relevant customers is critical. Toronto Hydro will abide by residential community by-laws such as noise levels placed by the City of Toronto and coordinate with all stakeholders as necessary.

E6.4 Network System Renewal

E6.4.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 90.3	**2020-2024 Cost ($M):** 92.4
Segments: Legacy Network Equipment Renewal (Automatic Transfer Switches & Reverse Power Breakers); Network Unit Renewal; Network Vault Renewal; Network Circuit Reconfiguration	
Trigger Driver: Failure Risk	
Outcomes: Reliability, Safety, Environment, Financial	

The Network System Renewal program (the "Program") addresses deteriorating and functionally obsolete underground network system assets serving primarily small to medium-sized customers in the pre-amalgamation City of Toronto. These customers reside in the City's core and are often sensitive to outages.[1] Examples include commercial businesses, GO Transit, and hospitals. The Program is designed to deliver reliability improvements and mitigate public safety risks by: (1) replacing high-risk, obsolete assets like Automatic Transfer Switches ("ATS") and Reverse Power Breakers ("RPB"); (2) replacing non-submersible network units and vaults in deteriorated condition; and (3) reconfiguring and re-cabling sub-optimal grid networks.

The Program is grouped into the four segments summarized below and is a continuation of the network renewal activities described in Toronto Hydro's 2015-2019 Distribution System Plan.[2]

- **Legacy Network Equipment Renewal**: continues the replacement of obsolete ATS and RPB on the secondary network. These assets are no longer produced by the manufacturer and cannot be properly maintained or replaced on a like-for-like basis. ATSs and RPBs are prone to moisture ingress and can fail catastrophically, resulting in lengthy outages, vault fires and damage to connected and adjacent equipment. Toronto Hydro plans to replace all remaining ATS and RPB units with network transformer units, standalone network protectors

[1] As discussed in Exhibit 2B Section D2.2.2, the underground network system is the most reliable configuration available among Toronto Hydro's distribution schemes, and is therefore an ideal option for customers who are sensitive to outages and concerned about reliability. Toronto Hydro is piloting equipment in during 2015-2019 that will facilitate the expansion of network service to larger residential and commercial towers. Toronto Hydro expects this equipment to be deployed as part of the normal customer connections process in the 2020-2024 period.
[2] EB-2014-0116, Exhibit 2B, Section E6.9, E6.10, E6.11 and E6.12

("SANPs"), or 600A manual secondary switches by the end of 2022, prioritizing assets in the worst condition.

- **Network Unit Renewal:** a continuation of planned replacement of network units at risk of failure. As network unit condition deteriorates, the risk of failure increases, and with it the likelihood of consequences such as lengthy customer outages and vault fires. Since 2012, the network unit renewal segment has focused primarily on eliminating the significant failure risk associated with fibertop network units, a non-submersible unit prone with a high potential of catastrophic failure. Toronto Hydro plans to have essentially all remaining fibertops removed from the system by the end of 2019.

  Beyond 2019, this segment will continue to target the remaining types of non-submersible units. These units are susceptible to water ingress and elevated failure risks even when in good condition. Toronto Hydro will prioritize the worst condition and fastest deteriorating units as indicated by condition inspections and health index scores. Without intervention, the utility projects that 267 units will be materially deteriorated ("HI4") or at end-of-serviceable life ("HI5") by 2024. Customers have expressed support for reducing the risk of network vault fires and flooding,[3] and Toronto Hydro is pacing investments to accomplish this outcome. The utility plans to replace an estimated 200 units between 2020 and 2024, in addition to 43 units planned for 2018-2019. This rate of replacement is expected to reduce failure risk on the network system by improving condition-related asset risk across the network unit population. Toronto Hydro plans to install new network units that are submersible and equipped with sensors to monitor transformer, protector, and vault conditions, resulting in the cost-effective reduction of reliability, environmental, and safety risks associated with network assets.
- **Network Vault Renewal:** a continuation of Toronto Hydro's efforts to rebuild or decommission poor condition network vaults. These civil structures were generally built in the 1950s and 1960s, mainly beneath the sidewalks in the busy downtown core. Toronto Hydro must proactively address structurally deficient vaults in order to mitigate risks to public safety, employee safety, and system reliability, and to maintain the long-term viability of the distribution system. Without intervention, the number of network vaults in HI4 and HI5 condition is expected to increase from 40 to 114 by 2024. During the 2020-2024 period, Toronto Hydro plans to eliminate immediate structural deficiencies of 33 high-risk vaults identified through the ACA process as having at least material deterioration ("HI4"). Due to

[3] Exhibit 2B, Section E2.3

the complexity of this mostly downtown work, the rate of planned replacement is less than optimal. However, the planned pace is such that Toronto Hydro anticipates it will be able to prevent the number of vaults at end-of-serviceable-life ("HI5") from increasing.

- **Network Circuit Reconfiguration:** a continuation of Toronto Hydro's plan to mitigate the impact of multiple contingency failures on the network system. This segment involves reconfiguring and re-cabling secondary grid networks into more robust spot vaults and enhanced grids. The result will be minimized customer interruptions, improved planning, modeling, and operational flexibility, and enhanced ability of the network system to operate under extreme events (e.g. multiple contingency outages). Toronto Hydro plans to reconfigure its five largest secondary networks over the 2020-2024 period, an investment that is expected to deliver long-term reliability and resiliency benefits for network customers in the downtown area.

Toronto Hydro plans to invest $92 million in the Network System Renewal program in 2020-2024, which is a 2.3 percent increase over projected 2015-2019 spending in this Program (including forecasted inflation). This level of investment is necessary to maintain public and Toronto Hydro employee safety, and the service levels that downtown customers rely on and expect from the network system.

1 ## E6.4.2 Outcomes and Measures

2 **Table 2: Outcomes & Measures Summary**

Reliability	• Contributes to Toronto Hydro's Network Units Modernization measure and system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Eliminating legacy ATS and RPB equipment which is obsolete and prone to failure leading to feeder interruptions; ○ Replacing 200 network units at highest risk of failure due to poor condition or vulnerability to flooding; ○ Eliminating structural deficiencies of 33 high-risk vaults that are placing enclosed equipment at risk; ○ Replacing older network units with ones equipped with sensors to monitor vault conditions and enable quicker response to adverse network conditions; ○ Reducing average restoration time during a full network outage by reconfiguring networks to support all or most of the load; and ○ Reducing customer interruptions by a third during second contingency events, by reconfiguring networks to improve operability under multiple contingency events.
Environment	• Contributes to Toronto Hydro's environmental objectives by eliminating network units at high risk of failure and vulnerable to vault fires or oil spills.
Safety	• Contributes to Toronto Hydro's Network Units Modernization measure and safety objectives by: ○ Minimizing the risk of vault fires in densely populated downtown areas by eliminating the potential catastrophic failure of legacy ATS and RPB assets; and ○ Minimizing the risk of catastrophic transformer failures by replacing network units most at risk due to deteriorated condition or exposure to higher-risk environmental factors; ○ Eliminating potential trip and falling debris hazards at 33 vaults with significant civil deterioration.

Financial	• Contributes to Toronto Hydro's financial objectives by: ○ Reducing the need to dispatch crews in multiple contingency scenarios by reconfiguring the network to support all or most of the network load; and ○ Supporting reduction in summer peak reading inspections by enabling monitoring and control of network units (see Network Condition Monitoring and Control program[4]).

E6.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Safety, Environmental Risk, Reliability, System Efficiency

Toronto Hydro's network system plays an important strategic role in meeting the reliability expectations of interruption-sensitive downtown customers. The Network System Renewal program aims to replace network assets at risk of failure due to deteriorating conditions. The failure of these assets negatively impacts reliability and the effective operation of the network system and potentially increases the risk to public safety and Toronto Hydro's crews.

Toronto Hydro's low voltage secondary network distribution system includes the following assets:

- Standard Network Units that consist of primary switches, network transformers, and secondary network protectors, which are assembled into a single unit;
- Legacy Network Units that consist of ATSs and RPBs, both of which include associated subway transformers;
- Network Vaults, which contain the aforementioned equipment; and
- Secondary Cables, which connect the aforementioned equipment and provide service connections to customers.

The Network System Renewal program is needed to replace those assets that are at risk of failure in order to mitigate the associated safety, environmental, and reliability risks and to maintain the service levels that downtown customers rely on and expect from the network system.

[4] Exhibit 2B, Section E7.3

E6.4.3.1 Legacy Network Equipment Renewal (ATS & RPB)

The Legacy Network Equipment Renewal (ATS & RPB) segment is a continuation of the activities previously described in Toronto Hydro's 2015-2019 CIR filing. In 2015, Toronto had a total of 53 ATS and RPB units and by the end of 2019, 13 units will remain. Toronto Hydro plans to replace all remaining units over the 2020-2024 period.

This segment aims to reduce failure and safety risks associated with network equipment that are obsolete, past their useful life, in poor condition, and prone to failure. Failure can occur due to various factors, such as water penetration or exposure to heavy debris and contamination, which results in equipment rusting (see Figure 1 and Figure 2) and control electronics failure. Toronto Hydro will prioritize ATS and RPB unit replacements based on condition to mitigate the risk of equipment failures.

Figure 1: Rusting at Base and Footing of ATS Unit

Figure 2: Rusting on Equipment Surface

1. Failure Risk

In the event of a system fault, failed or defective ATS and RPB units may not operate as intended, and in some instances catastrophic failures can occur. RPB malfunction can prolong equipment exposure to large amounts of fault current, damaging equipment such as cables and transformers that are fed on common feeders. This damage can lead to vault fires and catastrophic failures. From 2010 to 2012, prior to the start of proactive ATS and RBP replacement, Toronto Hydro replaced a total of 33 ATS and RPB units reactively due to equipment deficiencies and failures. Over 20 percent of the combined population of ATS and RPBs are known to be rusted or have failed to operate in the field, and are thus considered high priority for replacement.

2. Functional Obsolescence

Toronto Hydro considers ATS and RPB units to be functionally obsolete equipment designs due to: (i) the equipment enclosure’s inability to prevent moisture ingress, which accelerates and leads to equipment failure, and (ii) the cessation of manufacturer support for this type of equipment, and the inability to procure spare parts for equipment repairs, making it difficult for Toronto Hydro to achieve alignment with current maintenance and inspection practices. Going forward, the lack of spare parts precludes long-term maintenance as a viable option to extend the service life of the assets. For these reasons, this legacy network equipment no longer meets Toronto Hydro's needs.

3. Safety and Environment

Failing ATS and RPB assets can potentially put the safety of the public and Toronto Hydro employees at risk. In some situations, catastrophic failure of such assets has resulted in damage to related equipment and caused vault fires that can harm individuals in proximity to the vault and release toxins into the environment. The inherent safety risk of vault fires is heightened by the fact that these assets are generally located in heavily populated downtown areas.

Such a fire occurred at 33 Princess Street on January 16, 2012 (see Figure 3). An ATS unit failed at approximately 1:25pm, igniting a vault fire in Toronto's downtown (i.e. near Front and Sherbourne) and affecting two feeders, A14GD and A15GD. This fire was contained within the ATS vault; however, the fire damaged the primary cables on both feeders as well as the two distribution transformers supplying 33 Princess Street. The feeders were isolated at the station and power was promptly restored to most customers. Approximately 460 students from George Brown College, 50 seniors from a nearby retirement home, 50 children from a daycare, and customers from 246 The Esplanade were evacuated because of this incident. Two large customers supplied solely from feeders A14GD and A15GD also experienced extended outages. Some were left without power until approximately 2:00 pm the following day (i.e. 24 hours).

Figure 3: Damage from a Vault Fire Caused by Failure of an ATS Unit at 33 Princess Street on January 16, 2012

E6.4.3.2 Network Unit Renewal

The Network Unit Renewal segment is a continuation of the activities identified in Toronto Hydro's 2015-2019 CIR filing. This segment aims to reduce failure risks associated with network units that are obsolete, in poor condition, past their typical useful life, and prone to failure. The goal of the segment is to replace the most at-risk units, as indicated by obsolete design and condition assessment data, before they fail and potentially cause safety or environmental incidents such as fires and oil leaks.

Although replacements are prioritized based on condition, the network units that are replaced are typically of legacy "non-submersible" designs characterized by "ventilated" or "semi-dust-tight" protectors (see Figure 4). These units are susceptible to water ingress and elevated failure risks even when in good condition. These units also typically contain electro-mechanical relays that are not capable of condition monitoring or control. They are replaced with units that are of a submersible design, containing digital relays, and capable of meeting the requirements for Toronto Hydro's Network Condition Monitoring and Control program.

Figure 4: A ventilated network unit is shown on the left and a submersible network unit is shown on the right. The black protector is of a submersible design, which prevents water ingress.

1. Failure Risk and System Efficiency

Two main failure modes can impact a network unit. The first is flooding of the network vault that may damage the protector mechanism causing the unit to short, or fail to operate. The second is an internal transformer failure that is typically caused by overloading, low oil, moisture ingress, or age-related insulation deterioration. To maintain network system reliability, network units need to be both routinely maintained and proactively replaced when they are at an increased risk of failing. Maintenance of network units is summarized in Exhibit 4A, Tab 2, Schedule 2. Not replacing deteriorated network units in a timely manner can lead to equipment failures, and in turn cause interruptions to customers, oil leaks of 1,000 litres and more, and potential vault fires that may impact (including expelling smoke) busy arterial roads in the downtown core of Toronto.

Replacing deteriorated non-submersible ventilated protectors located in areas prone to flooding with submersible protectors that feature watertight cases can help address flooding risks. Toronto Hydro addresses failure risk due to equipment deterioration by prioritizing the replacement of aged units based on condition. Of Toronto Hydro's 1,800 network units, approximately 800 have non-submersible protectors, which are legacy designs that were used prior to the installation of the first submersible units in 2003. As a result, virtually all units older than 15 years are ventilated or semi-dust-tight. Figure 5 below shows the proportion of submersible non-submersible network units by age. The useful life of network units is 35 years of age.

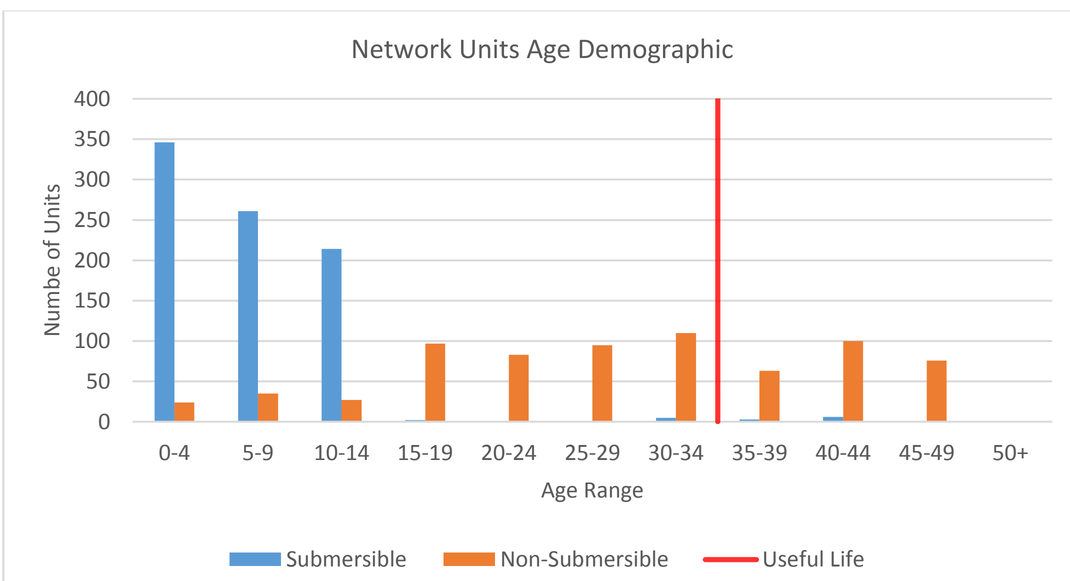


Figure 5: Network units' age demographic by type.

Despite the elevated risks associated with non-submersible network units, Toronto Hydro is proposing to replace units that exhibit deteriorated conditions only. Based on available ACA data, the current and estimated 2024 health index distribution (without proposed work) for network units is shown in Figure 6. HI4 means "material deterioration" and HI5 means "end of serviceable life". There are 267 units that are forecasted to have at least material deterioration by 2024 (including 102 HI4 and 165 HI5) and the network unit renewal segment plans to replace 243 of them, at an average rate of 40 per year for 2020-2024. For 2018 and 2019, 20 and 23 units are planned for replacement, respectively.

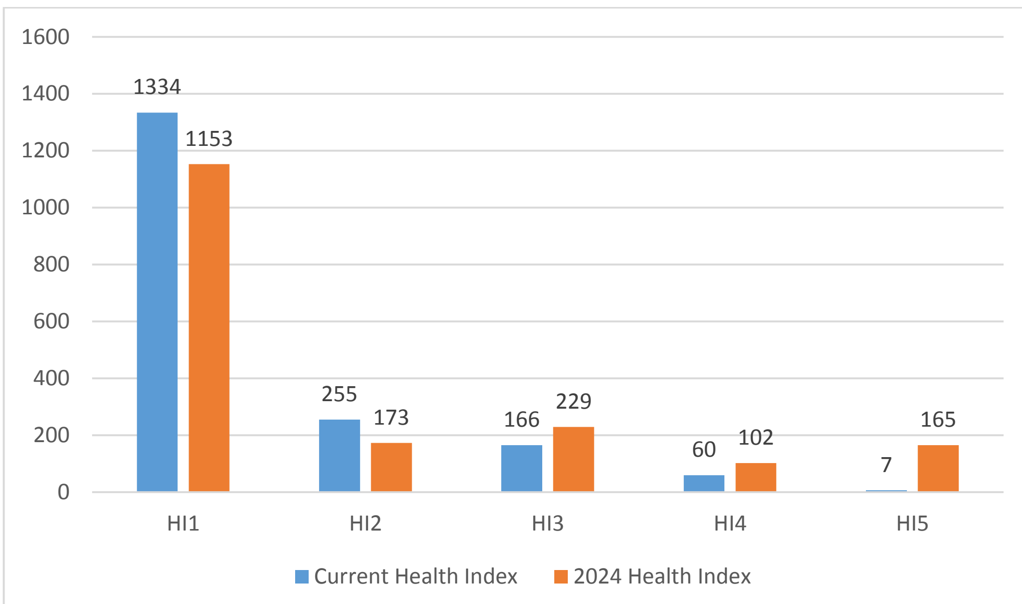


Figure 6: Network Transformers Current and 2024 Forecast (without Renewal) Health Index

2. Safety and Environment

Failure of deteriorated network units can result in both safety and environmental incidents. From a safety perspective, catastrophic failures may cause damage to surrounding property and put the public at risk of injury, especially given that network vaults are typically installed under sidewalks with significant pedestrian traffic. From an environmental perspective, corroded and deteriorated network units may result in oil leaking within a vault, and the possibility of oil escaping through vault drainage system into the environment. Over the 2015-2017 period, Toronto Hydro has experienced 223 oil leaks from network transformers. As network transformers typically contain more than 1,000 litres of oil, oil leaks have the potential to lead to serious environmental consequences. Figure 7 shows the size distribution of 223 network transformer oil leaks experienced by volume of oil leaked.

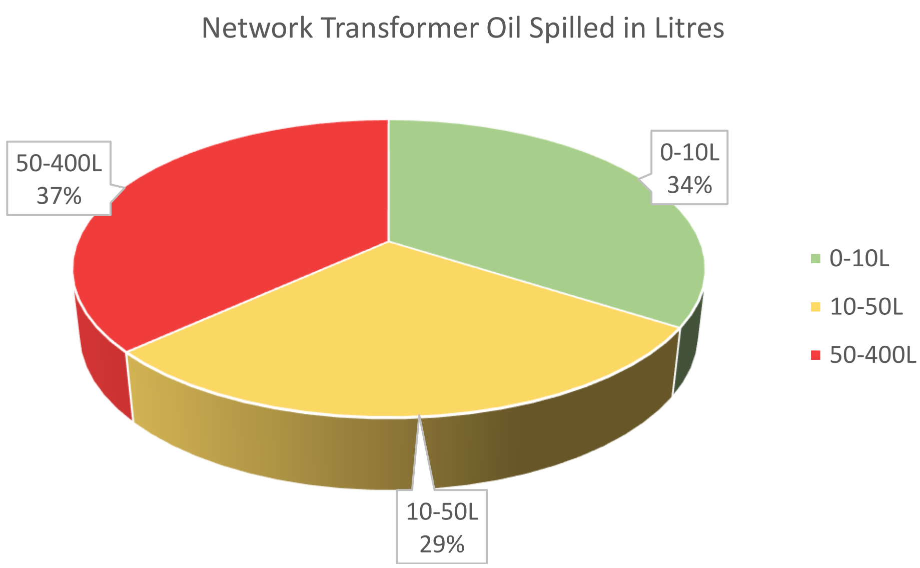


Figure 7: Network Transformer Oil Leaks 2015-2017

Oil leaks are mitigated by replacing deteriorated units and units operating in environments which place them at elevated risk.

E6.4.3.3 Network Vault Renewal

The Network Vault Renewal segment is a continuation of the network vault rebuild and decommissioning activities previously detailed in Toronto Hydro's 2015-2019 CIR filing. Many network vaults associated with the secondary network system were constructed in the 1950s and 1960s, mainly beneath the sidewalks in the busy downtown Toronto core. Today, these assets have many critical structural issues and Toronto Hydro plans to address the worst of them based on condition data. The aim of this segment is to reduce failure risks that can negatively impact the reliability and effective operation of the utility's distribution system as well as safety risks to the public and Toronto Hydro crews.

1. Safety

Table 4 highlights different safety risks to the public and Toronto Hydro crews from deteriorated network vaults. There are two main types of risk to the public. First, cracking and structural shifting of vault roof structures pose trip and fall hazards. Second, complete failure of roof elements can expose the public to energized electrical equipment.

Table 4: Safety Risk & Descriptions

Safety Risk	Description
Slips, Trips & Falls	A deteriorated vault roof may result in uneven grading on sidewalks or walkways and lead to slips, trips, or falls, which could cause injury to members of the public or Toronto Hydro crews.
Falling Debris	Toronto Hydro crews working inside the vault may encounter falling debris from the deteriorated roof or walls of the vault. This could lead to serious injury, especially when working near live equipment.
Fire	Poor condition of vaults can be a contributing factor to catastrophic failures such as vault fires.

The risk posed by cracking and structural shifting can be controlled by a maintenance program that patches or grinds down hazardous structural elements as needed. However, once a vault reaches the point where major structural deficiencies cannot be addressed by maintenance, three different options are available:

- **Decommissioning vaults** (see Figure 8) that are no longer needed as a result of load displacement. The typical cost to decommission a vault is approximately $50,000 to $150,000 and it takes approximately one month to perform the work;
- **Rebuilding the vault roofs** (see Figure 9) where severe structural deficiencies have been identified, but which are located on network vaults that are otherwise structurally sound. The typical cost of rebuilding a vault roof is up to approximately $250,000 and it can take approximately three months to perform the work;
- **Rebuilding entire vaults** (see Figure 10) that have been identified as having severe structural deficiencies requiring a complete reconstruction. These vaults cannot be decommissioned but require more extensive repairs beyond a vault roof replacement. The typical cost for rebuilding a vault is up to approximately $1 million, which includes the average costs for both civil and electrical work. This work can take between 18 and 24 months to complete.

Toronto Hydro also considers evolving customer needs and system requirements when choosing the best course of intervention for any given vault location.

Figure 8: In-Progress Vault Decommissioning

Figure 9: Temporary Roof during a Roof Rebuild

Figure 10: Completely Rebuilt Vault

For the 2020 to 2024 Network Vault Renewal segment, Toronto Hydro plans to address the immediate structural vault deficiencies of 33 high risk vaults identified through Toronto Hydro's ACA process as having at least material deterioration. In addition to the ACA process, Toronto Hydro carries out civil assessments wherein a civil engineer visually inspects the network vault roof and walls to recommend whether a roof or whole vault rebuild is required.

2. Failure Risk

Vault structural deficiencies are mainly caused by old age and exposure to adverse environmental factors. Currently, Toronto Hydro has 994 network vaults, predominantly in the downtown core, supplying the network system. Figure 11 shows the age distribution of all network vaults with reference to the useful life of both the overall vault (60 years) and the roof (25 years).

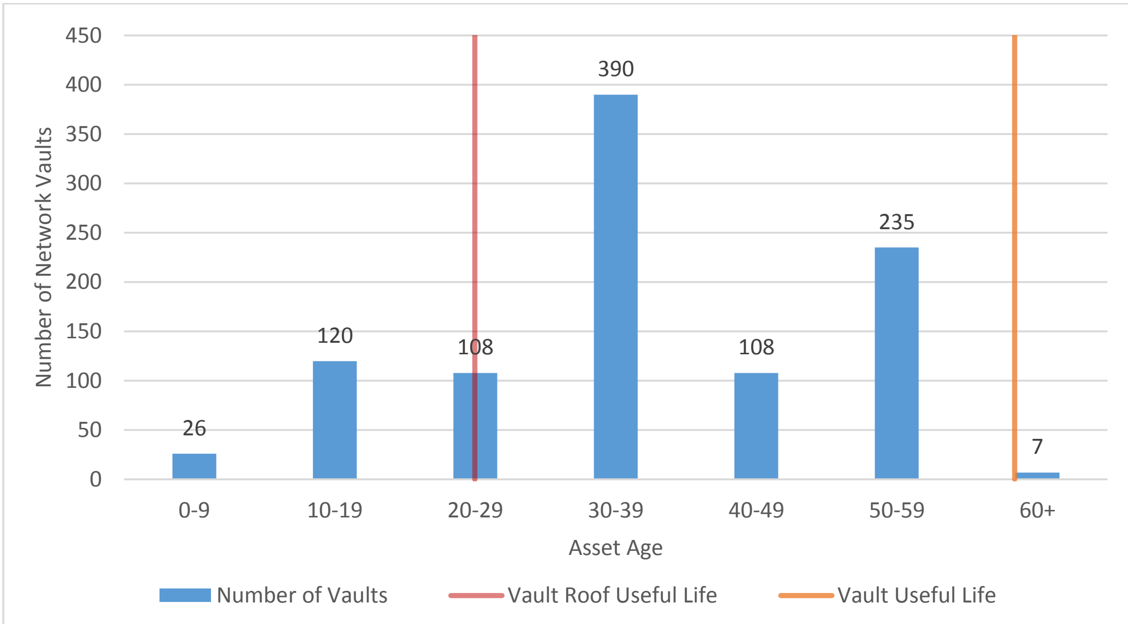


Figure 11: Age Distribution of Network Vaults

The vast majority of vault roofs have reached the end of their expected useful life of 25 years. In addition, over 25 percent of the vault civil structures will reach the end of their expected useful lifespan of 60 years within 10 years. ACA results show that some vaults are aging at an accelerated pace and require repairs even though they have yet to reach their expected lifespan. Increased use of de-icing salts in recent years is contributing to this accelerated aging.

Figure 12 shows that as at the end of 2017, 40 (7 percent) of Toronto Hydro-owned network vaults exhibit at least material deterioration (HI4 and HI5) and are clear candidates for work under this renewal segment. This number is forecasted to grow to 114 (21 percent) in 2024 without the proposed work. To alleviate the risks posed by deteriorated vaults, Toronto Hydro plans to address 33 of these network vaults between 2020 and 2024.

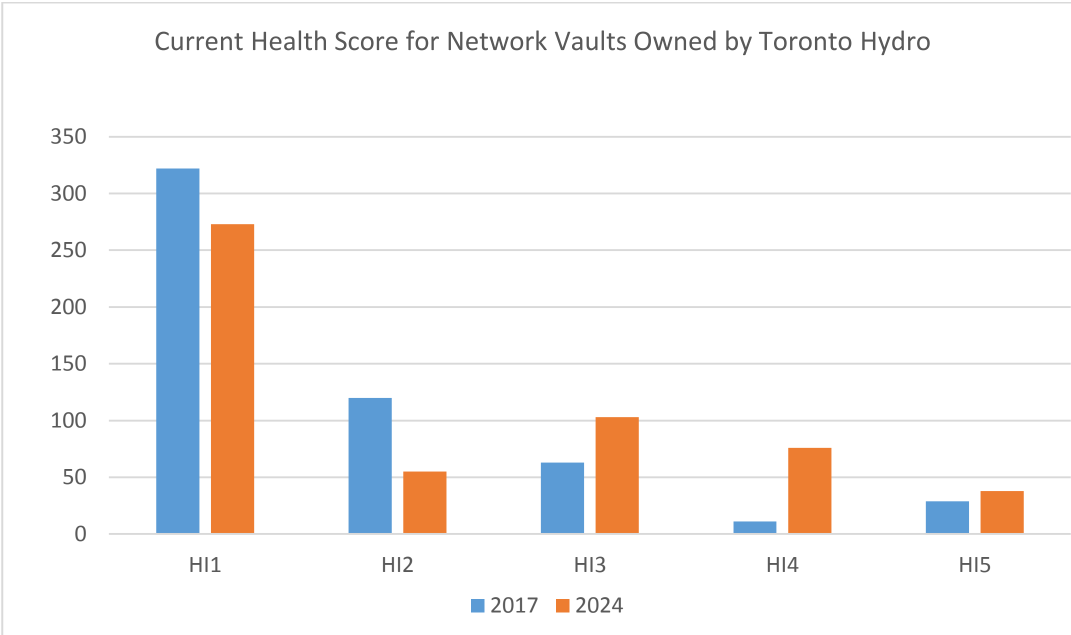


Figure 12: Current and 2024 Health Scores for Toronto Hydro Network Vaults

Some commonly found structural deficiencies caused by asset aging and environmental factors are described in Table 5. Examples of these deficiencies are also shown in Figure 13, Figure 14, Figure 15, and Figure 16 below.

Table 5: Vault Structural Deficiencies and Impacts

Deficiency	Impact
Exposed Roof Rebar	Failure risk that can lead to roof collapse, damage to equipment and safety hazard to the public and Toronto Hydro crews.
Exposed Wall Rebar	Failure risk may result in collapse of the vault walls, potentially leading to damaged equipment, costly repairs, safety hazards, and power outages.
Corroded I-Beams	Failure risk due to age and environmental factors can lead to collapse of the roof structure.
Cracked Roof	Exposes electrical equipment to leaking water and accelerated corrosion which may result in catastrophic failure.
Cracked Walls and Floor	Increases risk of failure causing flooding and damage to equipment which may result in large outage.

Figure 13: Roof and wall with exposed rebar

Figure 14: Corroded I-beams

Figure 15: Cracked roof and wall

Figure 16: Deteriorated Vault Floor

3. Reliability and System Efficiency

As discussed above, there are several failure modes and deficiencies that may lead to structural failure within a vault. Such damage to the network vaults is likely to negatively affect the performance of the electrical equipment contained inside, potentially contributing to a catastrophic failure of the network assets contained within the vaults and thereby causing a power outage in the downtown core. Such a power outage could impact between 500 customers (5 MVA) for smaller network grids and up to 3,000 customers (50 MVA) for the large network grids in the downtown core. The outage can last between several hours to a few days, depending on the location and the network distribution system being impacted.

If a vault roof is not replaced in time, removing it later to replace faulty equipment can cause it to collapse and thereby make it more dangerous and challenging for the crew to replace the equipment. In this scenario, the feeder providing power supply to the failed equipment will be turned off for longer periods of time, which will increase the risk of an outage to the customers fed by that feeder. In order to maintain reliable service to interruption-sensitive downtown customers, it is imperative that these assets be renewed before they fail.

E6.4.3.4 Network Circuit Reconfiguration

Toronto Hydro plans to reconfigure large network grids so that either: (i) sufficient grid flexibility is introduced to enable the sustainment of second contingency events; or (ii) sufficient customer loads are automatically dropped during second contingency events to allow the remainder of the grids to continue operating reliably.

A reconfigured network should, by design, shed sufficient load under second contingency conditions to allow the remainder of the grid to continue to operate. The network grids targeted for reconfiguration between 2015 and 2024 have six feeders on average and an average of 30 MVA. In a second contingency event, instead of losing all 30 MVA, the reconfigured networks would only lose about 10 MVA. This equates to a 67 percent reduction in interrupted load.

The Network Circuit Reconfiguration segment uses a number of different methods to address the problems and risks associated with multiple contingency events. The methods used depend on the configuration of the network and the requirements needed to reconfigure it into a robust system that supports second contingency. A single reconfiguration project may utilize multiple methods including:

- **Splitting grid into spot vaults:** This option solves overload problems under second contingency events that could result in equipment failure, and eliminates the need for power system controller intervention during these events.
- **Splitting grid into enhanced mini-grids:** This option is able to better sustain customer loads under multiple contingency events than what is possible using the first option. However, a third contingency would still result in a serious transformer overload and require prompt action by the power system controllers to identify the problem and shed load accordingly.
- **Upsizing transformers:** The option allows all customer loads to be sustained during any second contingency condition; however, a third contingency would still result in a serious transformer overload and would require prompt action by the power system controllers to identify the problem and shed load accordingly.
- **Changing primary feeder connections to network transformers:** This option improves diversity in the feeders supplying the network, thereby making it more resilient to multiple contingency events.
- **Reinforcing existing secondary network grid cabling:** This option ensures secondary cabling is not overloaded during multiple contingency events.

1. Failure Risk

Network Circuit Reconfiguration mitigates the impact of failures. Failure risk on the network system has increased over time due to:

- **Evolving Operating Practices:** The secondary network system was originally designed to burn clear faults and self-isolate damaged equipment so that most failures of network transformers and primary and secondary cabling do not result in customer interruptions. However, a small number of transformer failures result in vault fires. The fire department's current practice is to require that Toronto Hydro immediately cut all power supplies into the vault as a first step in fighting the fire. As a consequence, multiple network primary feeders must be tripped, which may leave insufficient remaining contingency capacity to sustain the network grid.
- **Multiple Contingency Events:** Operation of the network system under multiple contingency scenarios imposes challenging requirements on operating personnel. First, a network expert must analyze the grid to identify critical overload conditions and propose customer load reductions and necessary reactive tasks, all within restrictive time limits. If an expert is not immediately available at the control center, power system controllers may be forced to drop the entire grid in order to prevent a network cascade failure. Second, once the necessary reactive switching and load reduction tasks are identified, system response crews must perform this work, and customers need to reduce their loads within the identified time limitations.
- **Reach of the Secondary Network Distribution System:** The secondary network distribution system represents 13 percent of the downtown Toronto peak load (or approximately 230 MVA of 1800 MVA based on 2015 data). Although it is Toronto's most reliable distribution system, when a major secondary network equipment failure occurs, the impact is widespread. Often major portions of station switchgear, with up to 50 MVA of customer load (equivalent to approximately 25,000 residential customers), must be interrupted following such events.

For a typical network with six primary feeders, a widespread forced outage due to a second contingency event would cause about 30 MVA of load to be dropped for four hours to prevent equipment overload. In recent years, these events have occurred approximately once every three years. A reconfigured network grid should be able to sustain a second contingency incident without requiring the entire network to be dropped. This should typically result in a two-thirds reduction in interrupted load.

2. Reliability and System Efficiency

The network system in Toronto was designed for first contingency operation. Under any first contingency event, power system controllers do not need to take any action to ensure continued reliable supply to network customers. On the other hand, multiple contingency events would require immediate action by power system controllers and system response crews. Often, only minutes are available to take effective action in order to prevent a network cascade failure. As previously mentioned, Network Circuit Reconfiguration enables a network to sustain a second contingency incident without requiring the entire network to be dropped. Since almost all network emergencies involve only first and second contingency outages, this will result in an efficiency improvement in terms of system control.

In addition, most multiple contingency network emergencies require the power system controllers and system response crews to spend hours conducting switching operations to stabilize the network and restore as many customers as possible. As a result, isolation and repair of failed equipment may be delayed until this work is completed. Network Circuit Reconfiguration is expected to reduce the workload required to stabilize the network and restore customers, and allow restoration work to begin at the earliest opportunity, thereby minimizing the time required to restore the network to normal operation.

Table 6 identifies the networks targeted for reconfiguration in the 2020-2024 period. All networks targeted will be reconfigured after they have been updated with monitoring and control through the Network Condition Monitoring and Control program[5]. Through Network Condition Monitoring and Control alone, it is expected that one-third of total network load will be preserved during second contingency events. A reconfigured network will typically preserve two-thirds of the total load during these events (representing an additional one-third savings during second contingency events on networks already updated with condition monitoring and control). The synergies between these two programs are expected to allow many customers to be sustained even during rare third contingency events.

[5] Exhibit 2B Section E7.3

Table 6: Targeted Networks for Reconfiguration

Network	Network Feeders	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Reconfiguration Year
WR-West Phase 1	9	55	12.5	2021
WR-West Phase 2	9		12.5	2022
GD Phase 1	9	49	11.6	2019
GD Phase 2	9		17.4	2020
A-North Phase 1	9	44	13.5	2023
A-North Phase 2	9		13.5	2024
CS-West Phase 1	8	45	11	2021
CS-West Phase 2	8		11	2024
CE-South Phase 1	8	32	6.5	2022
CE-South Phase 2	8		6.5	2023

The networks to be reconfigured during this filing period represent 50 percent of the major network system load. Multiple contingency events occur approximately once each year and the existing network system can reasonably cope with approximately two-thirds of these events.

3. Functional Obsolescence

The existing secondary grid network distribution system was initially designed for pure network loads and not the mixed network and radial loads that exist today. Network feeders are designed such that they can be highly loaded since loads are automatically redistributed across all other network feeders in case of an outage. However, because radial feeders cannot be loaded as highly, due to the need for them to pick up load during contingency scenarios affecting adjacent feeders, the overall utilization of a mixed feeder is reduced. Furthermore, because of the presence of radial loads on a mixed feeder, the capacity to operate the network under multiple contingencies becomes insufficient. Enhancement of secondary network grid flexibility is necessary to adapt to this new standard.

E6.4.4 Expenditure Plan

To address the critical underlying issues of the network assets in downtown Toronto, Toronto Hydro plans to invest $92.4 million in the Network System Renewal program during 2020-2024. Table 7 below provides Toronto Hydro’s annual Historical Year (2015-2017), Bridge Year (2018-2019) and estimated 2020-2024 expenditures for each of the Program segments.

Table 7: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Legacy Network Equipment Renewal (ATS & RPB)	1.0	1.1	3.3	1.8	1.4	1.9	2.0	1.2	-	-
Network Unit Renewal	4.7	7.6	8.3	6.2	11.2	9.5	9.8	10.0	10.1	10.2
Network Vault Renewal	4.6	8.0	2.3	8.6	15.4	6.0	6.1	6.2	6.3	6.5
Network Circuit Reconfiguration	-	0.0	0.7	2.2	1.8	1.2	1.4	1.1	1.2	1.7
Total	**10.2**	**16.8**	**14.7**	**18.9**	**29.8**	**18.6**	**19.3**	**18.5**	**17.7**	**18.3**

E6.4.4.1 Legacy Network Equipment Renewal (ATS & RPB)

The goal of the Legacy Network Equipment Renewal segment is to replace all obsolete ATS and RPB assets within the 2020 to 2024 period. During 2015-17, Toronto Hydro spent $5.4 million to complete replacements of 14 units and expects to spend another $3.2 million to replace 26 units in 2018-2019. Given that certain replacement projects take more than one year to complete, some project spending is allocated to the year prior to unit replacement, causing the unit completion to lag expenditures.

Variances from one year to the next are also attributed to site-specific complexities associated with replacing particular ATS and RPB units. By the end of 2019, Toronto Hydro forecasts to have replaced 40 units over the 2015 to 2019 period. For 2020-2024, 13 units are planned for replacement at a total cost of $5.1 million. Figure 17 shows the annual replacements (actual and forecast) and number of units remaining from 2015 to 2024.

Eliminating these obsolete, prone to failure legacy assets is expected to improve reliability downtown and contribute to Toronto Hydro's system reliability objectives, as well as improve safety by reducing risk of vault fires due to catastrophic failure. Units are prioritized for replacement primarily based on condition and failure risk (e.g. history of water penetration). Where applicable, replacement of ATS or RPB assets will be combined with other work in the Network System Renewal program (e.g. a network vault rebuild) in order to minimize costs and resource requirements.

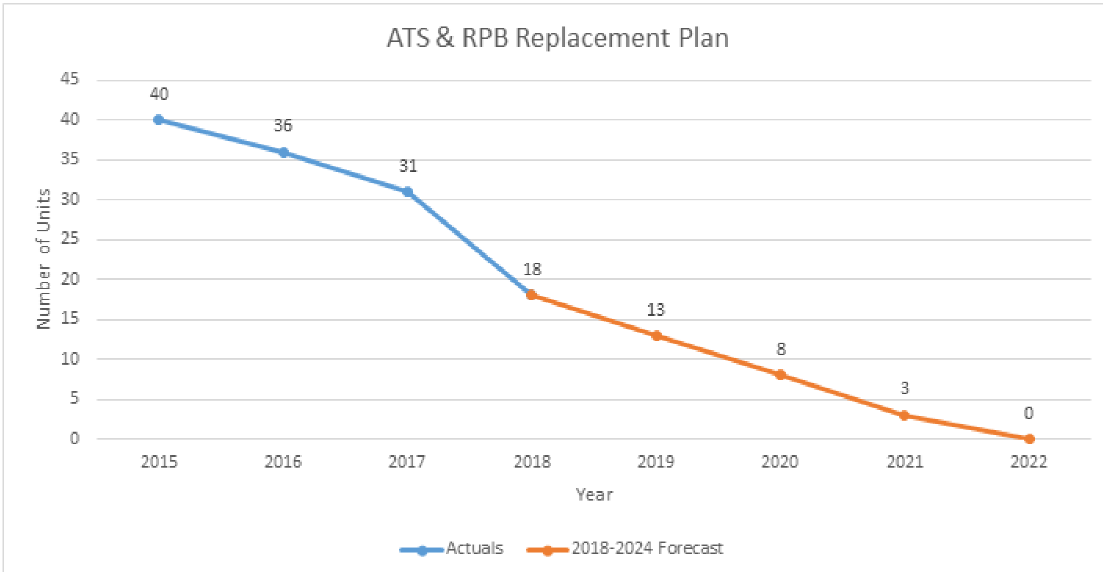


Figure 17: ATS & RPB Burn Down Chart

E6.4.4.2 Network Unit Renewal

The Network Unit Renewal segment replaces end-of-life network units on a planned basis and during 2015-2019 has focused on fibretop units. As of the end of 2017, 16 at risk fibertop units remain on the system and are expected to be essentially replaced by the end of 2019. Toronto Hydro expects to spend a total of $38.1 million on this segment over 2015-2019, which includes spending on Network Condition Monitoring and Control (discussed below). Expenditure vary from one year to the next based on the number of unit replacements and the installation of equipment and fibre optic cable to enable monitoring and control.

In 2015, 2016, and 2017, 17, 25, and 21 network units were replaced respectively. Forty-three additional replacements are planned for 2018 and 2019. The planned replacements are generally lower than were initially expected as deteriorating conditions necessitated the replacement of 127 units reactively during 2015-2017 (see Reactive and Corrective Capital program[6]).

In addition to the network unit replacement work, a portion of spend in this segment was allocated to Network Condition Monitoring and Control, which is included in this DSP as a new, separate program[7]. This work enables remote capabilities to monitor vault conditions such as temperature

[6] Exhibit 2B Section E6.7

and flooding as well as live loading on the network transformer units. Table 8 below shows spending for this part of the Network Unit Renewal segment (separately) over the 2015-2019 period.

Table 8: 2015-2019 Costs (Actual/Bridge): Network Condition Monitoring and Control

	Actual			Bridge	
	2015	**2016**	**2017**	**2018**	**2019**
Network Condition Monitoring and Control	0.2	1.6	3.3	2.8	3.1

Toronto Hydro's forecast cost for 2020-2024 Network Unit renewal is $49.6 million. This will fund the replacement of 40 units per year. 267 network units are forecasted to have at least material deterioration (HI4 and HI5), by 2024. Of these, Toronto hydro plans to replace 243; an average rate of 40 units replaced per year between 2020 and 2024. Replacement of units with the highest failure risk is expected to improve downtown reliability and reduce the safety and environmental risk associated with those units. In addition, newer units will be equipped with new features (e.g. monitoring capabilities to enable faster response to developing problems; and submersible protectors).

In order to minimize costs and use resources efficiently, Network Unit Renewal projects will be combined with overlapping work within the other Network System Renewal segments, where possible. In addition, work on at-risk units fed from a common feeder will be planned to be executed in the same year. The asset condition data collected from inspections (conducted three times per year) is used to determine replacement priority within specific asset classes. Severely deteriorated assets are given the highest priority. Non-submersible units located in areas prone to flooding are also prioritized. Projects can be reprioritized if an urgent need is discovered.

E6.4.4.3 Network Vault Renewal

The Network Vault Renewal segment rebuilds vaults and vault roofs. Over 2015-2017, Toronto Hydro spent $14.9 million to rehabilitate (or decommission) 34 vaults. During 2018-2019, Toronto Hydro expects to spend another $24 million to address 29 vaults.

Variances between years are primarily due to costs associated with particular vaults. Costs for civil work tend to vary greatly between projects because such projects tend to impact city and other utility infrastructure outside of the immediate site. In addition, civil construction projects are impacted by timing and constraints imposed by other major work in the city, such as the Eglinton LRT.

Toronto Hydro plans to spend $31.1 million to rehabilitate 33 of the highest risk vaults during the 2020-2024 period (i.e. approximately seven vaults per year). Through this work, Toronto Hydro expects to improve safety and reliability by removing potential trip and falling debris hazards and reducing the risk that any structural deficiencies could lead to damaged equipment. Figure 18 shows the locations of various proposed projects.

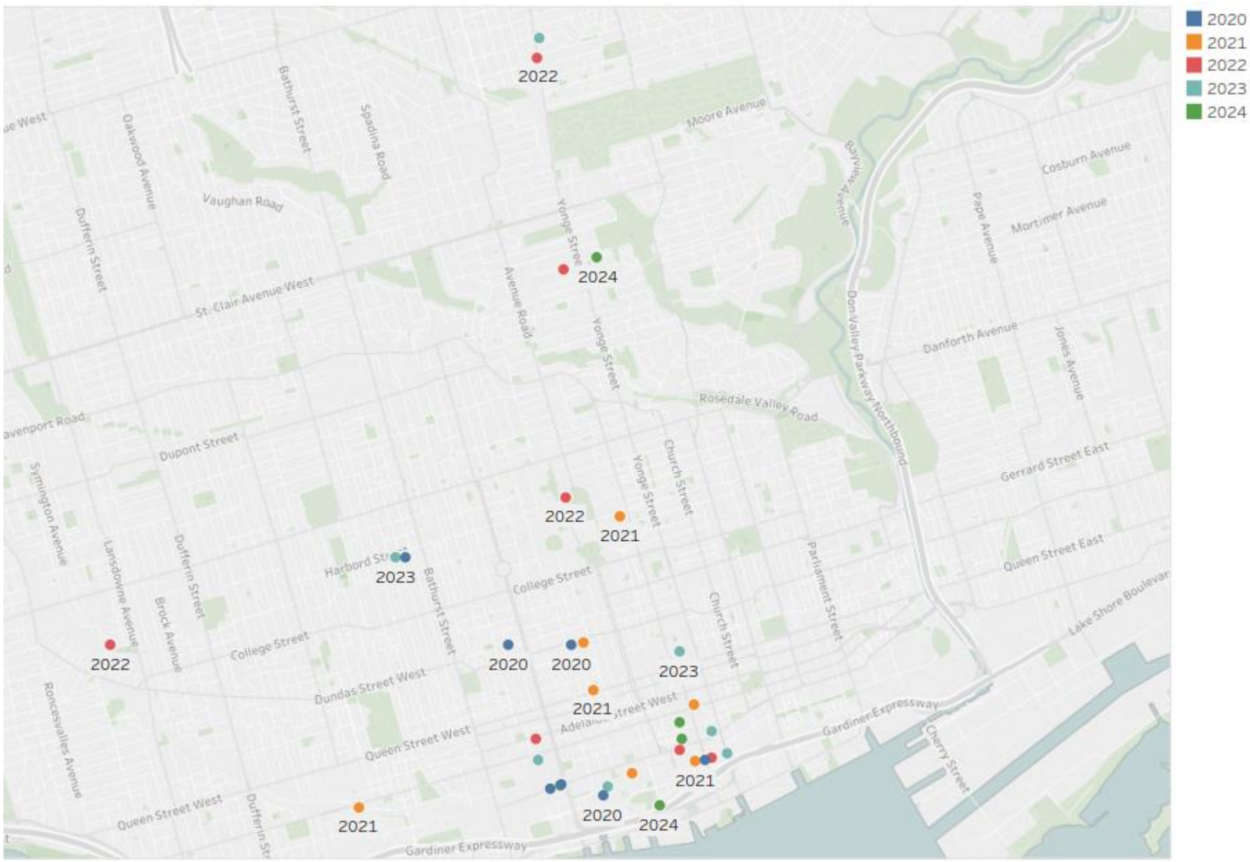


Figure 18: Locations of Network Vault Renewal Projects (2020-2024)

Where applicable, Network Vault Renewal work is combined with overlapping work in the other Network System segments to minimize resource requirements and costs. In addition, projects requiring civil construction work are coordinated with planned City road work to reduce costs associated with routing civil infrastructure around road moratoriums and road cut repairs.

E6.4.4.4 Network Circuit Reconfiguration

The Network Circuit Reconfiguration segment mitigates the impact of multiple contingency events on Toronto Hydro's network system. Through the 2015-2019 period, Toronto Hydro spent $0.7 million on this segment over 2015-2017 and expects to increase spending to $4.0 million over 2018-2019. The variance in spending between 2015-2017 and 2018-2019 is attributed to the timing within the period of the four pilot projects to implement the new 600V network system and the three network grid reconfiguration projects.

The first 600V pilot project began in 2017. Toronto Hydro expects to install the new 600V network system at four other locations (PCS – 1033 Bay St., CTS – 222 Spadina, DHC – 340 College St. and ECE – 25 The Esplanade) in 2018 and 2019. Toronto Hydro expects to complete the reconfiguration of three network grids in 2018 (Cecil North, Carlaw East, Carlaw West) and a portion of the George & Duke network is planned for 2019, with the remainder carrying over into 2020. For 2018, Toronto Hydro is also planning a project to convert an existing subfeeder distribution area to a network system to improve reliability.

Toronto Hydro plans to spend $6.7 million to reconfigure five networks over the 2020-2024 period. Table 6 lists the secondary grid networks chosen for reconfiguration in 2020-2024 based on their size and loading. Toronto Hydro is targeting the five largest networks and expects that their reconfigurations will help to improve outage restoration time and reduce risks associated with second contingency events for downtown network customers.

To minimize costs and resource requirements, Network Circuit Reconfiguration projects are combined with overlapping work in the other Network System Renewal segments, where applicable. Reconfiguration work can vary significantly from one network to another and this holds particularly true during the 2020-2024 period, where the five targeted networks service the most load with complex configurations.

E6.4.5 Options Analysis

E6.4.5.1 Options for Legacy Network Equipment Renewal (ATS & RPB)

Toronto Hydro evaluated the following options for addressing obsolete and deteriorated ATS and RPB units.

1. **Option 1: Reactive Replacement Approach**

This option entails continuing to operate the ATS and RPB units as is and replacing them reactively upon failure. While failure rates have increased substantially in recent years, manufacturer support and spare parts are not available. Accordingly, maintaining the status quo will negatively affect system reliability and will pose potential safety risks to customers as well as Toronto Hydro personnel. As such, this option is not recommended.

2. **Option 2: Like-for-Like Replacement**

This option would replace ATS and RPB units with identical units which are no longer considered the standard. The use of non-standard equipment can be very expensive due to high engineering, training, maintenance, manufacturing and inventory costs spread over a relatively small number of assets. These legacy units are no longer supported by manufacturers and therefore, need to be custom made. In addition, when custom equipment is purchased, availability of spare parts and support is limited. As such, this option is not recommended.

3. **Option 3 (Selected Option): Replacement with Standard Equipment at Proposed Pace**

Replacing legacy network equipment with standard equipment at the pace proposed in the Expenditure Plan will eliminate all remaining ATS and RPB units by the end of 2022. Standard Toronto Hydro network equipment such as 600 A secondary manual switches, stand-alone network protectors, and network transformer units are used to replace legacy network equipment. This allows Toronto Hydro to continue to supply its customers reliably and mitigates the safety risks outlined in this narrative. This option is also the most cost-effective for Toronto Hydro's customers as equipment replacement is prioritized on an asset condition basis, thereby minimizing the likelihood of equipment failure, and minimizing negative impacts to customer reliability. Although reliability and safety risks of these legacy units are mitigated through this plan, some risk will remain until the end of 2022 when all ATS and RPB units will be replaced. However, this is the recommended option as this level of risk is considered acceptable and the pace of work and spending within this segment is reasonable.

4. Option 4: Replacement with Standard Equipment at Accelerated Pace

By accelerating the pace of work, Toronto Hydro could replace all remaining ATS and RPB units with standard equipment in 2020. This pacing results in the lowest likelihood of ATS and RPB equipment failure; however, it requires that financial and labour resources be applied all at once. Spreading out replacements over the 2020 to 2024 period permits some of these 2020 resources to be applied to other programs that also have assets in varying states of deterioration. Doing so does not change financial and labour resource expenditures over the entire 2020 to 2024 period, but does allow projects in different programs to be collectively prioritized so that risks to safety and customer service reliability are minimized overall. Therefore the option described in Section 5.1.3 above is the preferred option.

E6.4.5.2 Options for Network Unit Renewal

Toronto Hydro considered the following options for addressing network units in poor condition.

1. Option 1: Reactive Replacement Approach

Under this option, Toronto Hydro would continue to maintain existing deteriorated network units and replace each unit upon failure. By maintaining the status quo, the multitude of issues discussed throughout the narrative, including the risk of catastrophic failure due to poor condition or flooding and the associated safety and associated public safety and environmental risks (e.g. oil leaks) would persist. This option is not recommended.

2. Option 2 (Selected Option): Replace Deteriorated Network Units at Proposed Pace

Toronto Hydro's plan addresses safety risks associated with deteriorating network units and would improve reliability and efficiency of the network system. The utility expects the replacement of network units to result in avoided direct and indirect costs associated with in-service asset failures, such as the costs of customer interruptions, emergency repairs and replacement. At the proposed pace of 40 units per year, 243 of the 267 units forecast to have material deterioration by 2024 would be replaced and their associated safety, environmental and reliability risks addressed. However, those remaining units with material deterioration not replaced by 2024 or ones not replaced in a timely manner will continue to pose a higher risk of failure with the potential to cause fires or oil leaks until they are replaced. Some legacy, non-submersible units without material deterioration, but still at an elevated risk of failure due to flooding, would also remain unaddressed. This is the recommended option as it is expected to result in an acceptable, but not ideal, reduction in the number of at-risk units at a reasonable level of spending.

3. Option 3: Replace Deteriorated Network Units at Accelerated Pace

With this option Toronto Hydro would replace network units at an accelerated rate of 62 units per year to achieve faster reduction of safety and reliability risks associated with deteriorating network units. At this pace, Toronto Hydro would replace most of the 267 units forecast to have material deterioration as well as the majority of network units which will be past their useful life of 35 years by 2024. This would minimize the number of network units at elevated risk of failure, however, it would also cost more than the proposed pace and is therefore not the recommended option.

E6.4.5.3 Options for Network Vault Renewal

Toronto Hydro considered the following options for addressing network vaults in poor condition.

1. Option 1: Maintenance Approach

Under the status quo option, Toronto Hydro would continue to maintain the network vaults in their current state. Maintenance of the vaults involves structural fixes of the roof, wall(s) and/or floor as identified through biannual network vault inspections. Because the vaults proposed for renewal have material deterioration, maintaining (rather than rebuilding) them will inevitably increase the risk of structural failure, which may lead to failure of the equipment housed inside the vaults. Furthermore, safety risks (e.g. tripping and falling hazards) for both the public and Toronto Hydro crews would be elevated. Under this option, Toronto Hydro would be required to resolve these issues reactively, incurring higher costs and unplanned interruptions of supply to the customers. This option is not recommended.

2. Option 2 (Selected Option): Address Deteriorated Network Vaults at Proposed Pace

Toronto Hydro's plan to proactively renew the highest risk network vaults, which have material deterioration, at a rate of five to seven per year is expected to reduce the risk of injury to the public and Toronto Hydro crews and the risk to system performance due to asset failure. These investments would also result in long term benefits (including prolonged expected life and improved standards and materials) for the civil structures of the vaults as well as the equipment housed inside them.

Based on experience to date, Toronto Hydro expects this pace to be achievable and to help mitigate the expected rise in the number of network vaults with material deterioration over the 2020-2024 period. Although Toronto Hydro would address the highest risk vaults, there would still be over 200 network vaults beyond the end of their useful life and over 80 forecast to have material deterioration in 2024. These vaults would continue to pose elevated safety and reliability risks. However, this is the recommended option as it is expected to mitigate risks to an acceptable degree at a pace of work that would be realistically achievable at a reasonable cost.

3. Option 3: Address Deteriorated Network Vaults at Accelerated Pace

By accelerating the pace of network vault renewal, Toronto Hydro Toronto Hydro could go beyond mitigation of the expected increase in the number of network vaults with at least material deterioration and address the majority of all known vaults that are currently known to need work. Reliability and safety risks of deteriorated network vaults would be reduced faster and to a greater degree than with option 2. However, in addition to tripling forecast annual expenditures for this segment, this pace poses issues with resource and outage management resulting in delays of other planned work needed by the Toronto Hydro system and is therefore not recommended.

E6.4.5.4 Options for Network Circuit Reconfiguration

1. Option 1: No Network Configurations

The current operational constraints within the existing network circuit configuration create one to two complete network interruptions each year following multiple contingency network outages. Without additional network reconfiguration, network system reliability is expected to continue to degrade as new customer loads are added, radial and network loads are mixed on the same feeders, and operating practices are modified to enhance safety and satisfy new requirements. The secondary network distribution system would continue to become functionally obsolete and is expected to be less able to meet customers' changing needs, especially given their location in the city's high density downtown core.

2. Option 2 (Selected Option): Reconfiguration of Five Largest Networks

By reconfiguring the secondary network system's five largest network, operating efficiencies can be realized from the reduced amount of load (reduced on average by two-thirds) that needs to be dropped following multiple contingency events on those networks. Furthermore, it would reduce the workload required to stabilize the networks and restore customers following multiple contingency events and reduce the time required to restore the networks to normal operation. The five targeted networks service the most load and have complex configurations, which means that they would benefit the most from reconfiguration. However, virtually all networks in the downtown would benefit from reconfiguration and those that are not reconfigured are expected to continue to be subject to the reliability, functional obsolescence, and system efficiency issues discussed for the status quo option and in section 3.4. Nevertheless, this is the recommended option as it targets an acceptable level of spending on reconfiguring the networks that will have the greatest impact.

3. Option 3: Reconfiguration of All Major Secondary Network Grids

In addition to the five largest networks described in option 2, eight more networks would be reconfigured. These eight networks would include High Level-Bloor, High Level-St. Clair, Windsor-East, Terauley-East, Duplex-South, Charles-East, Duplex-East, and Charles-St. James. This would extend the benefits described above to the entire secondary network system by 2024. However, Toronto Hydro estimates that this would require approximately three times the financial and labour resources per year as the chosen plan and is therefore not recommended.

E6.4.6 Execution Risks & Mitigation

The Network System Renewal program is subject to the risks facing downtown underground programs and projects. For all segments, these risks include summer feeder restrictions. More specifically, many downtown network feeders have summer feeder switching restrictions imposed to prevent overloading cables and equipment during peak loading periods. To mitigate this risk, projects are scheduled to avoid the summer period if the feeders involved are restricted (i.e. do not have capacity). If a feeder is newly restricted in the project year, the project timeslot could potentially be exchanged with another project. If a restricted feeder supplies a vault being planned for rebuild, then the work may only be conducted during off-peak hours, and this may hinder project execution. Toronto Hydro's Load Demand program for 2015-2019 (see Section E5.4 of the DSP) is intended to help mitigate these risks by enhancing the grid so that feeder restrictions during summer peak times are minimized.

Each segment may also be subject to its own set of additional risks as discussed below.

The City and Toronto Hydro's customers often have special events scheduled that can be negatively impacted by a major construction project. Toronto Hydro communicates with stakeholders and customers to establish an agreeable timeline in accordance with system priorities. Should a conflict arise, the project timeslot could potentially be exchanged with another project to allow the overall Program to proceed without negative impact.

The removal of a network unit may cause the remaining network units to experience overloads. Toronto Hydro manages this risk by scheduling the replacement of problematic network units outside of the peak loading periods of the particular vault. For example, work on vaults supplying schools or buildings with electric heat may best be scheduled during the summer.

City moratoriums and the Metrolinx subway expansion may impact execution timelines. Although existing City moratoriums are considered when planning vault renewal projects, it is possible that new moratoriums may be subsequently introduced. To mitigate this risk, Toronto Hydro reviews all new moratoriums and adjusts its work plans accordingly. Projects such as the expansion of the transit system in Toronto pose special challenges. When such projects are in the execution phase, the City or Metrolinx may impose moratoriums that suspend all other work until critical phases of transit projects are completed. In addition, transit construction may require relocation of Toronto Hydro assets that impacts the Vault Renewal program. To mitigate this risk, Toronto Hydro communicates with Metrolinx on a continuing basis to identify, monitor, and resolve conflicts.

For the Network Circuit Reconfiguration segment, additional risks are posed by structures at the end of their useful lives and customer-owned civil structures. Projects in this segment typically involve the installation of new cabling within existing cable chambers and duct structures. There is a risk that the required structures will be at the end of their useful lives and may require replacement before the planned work can be executed. This would necessitate scope and timing changes to some projects. However, there are usually multiple options to reconfigure a network. Should the optimal design require civil structure replacement, an alternative that still provides the required reliability and operational improvements, but that does not require civil structure replacement, can likely be found. The design would be revised accordingly to mitigate the cost and timing impacts.

There also may be unforeseen condition or access problems with some customer-owned civil structures. In these situations, the customer may have to perform civil rebuild work before Toronto Hydro's work can commence, thereby causing project delays. This risk can be mitigated by fully inspecting all civil plants prior to finalizing project design, and introducing sufficient lead times for customer civil design and construction activities in the project schedule.

E6.5 Overhead System Renewal

E6.5.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 183.9	**2020-2024 Cost ($M):** 265.7
Segments: Overhead System Renewal	
Trigger Driver: Failure Risk	
Outcomes: Reliability, Environment & Customer Service	

The Overhead System Renewal program (the "Program") manages failure risk on Toronto Hydro's overhead system through the replacement of end -of -life, functionally obsolete assets that are in poor condition or require replacement to mitigate safety and environmental risks.

The Program is a continuation of the Overhead Circuit Renewal Program outlined in Toronto Hydro's 2015-2019 Distribution System Plan,[1] and aims to replace three major overhead asset classes: (1) pole-top transformers; (2) poles and pole accessories; and (3) overhead switches. These assets deteriorate over time due to exposure to harsh environments, usage and age, increasing the probability of asset failure. A summary of the Program's investments in the three major overhead asset classes is as follows:

- **Pole- top Transformers:** The main driver of poor performance in the overhead system is defective equipment in poor condition. Although Toronto Hydro has had some recent success in reducing the total number of overhead transformer failures, they have caused 24 percent of defective equipment outages on the overhead system over the last five years (2013 – 2017). Over the same period, overhead transformers have contributed over 6,000 customer hours interrupted and 10,000 customers interrupted per year on average. Approximately 14 percent of all overhead transformers have already passed their useful life and, without intervention, that number will increase significantly to 40 percent by 2024. This would not only negatively impact system reliability, but also result in a large back log of transformers beyond their useful life that has to be replaced after 2024. In addition, transformers at or beyond their useful life are at risk of having insulating oil containing PCBs that could be released to the environment. Through the Overhead System Renewal program,

[1] EB-2014-0116, Exhibit 2B, Section E6.4

Toronto Hydro plans to replace approximately 6,700 overhead transformers to minimize failures and the environmental risk associated with potential PCB oil spills.

- **Poles and Accessories:** Poles and pole accessories have caused over 40 percent of defective equipment outages on the overhead system over the past five years. Pole failures can lead to extensive and prolonged service disruptions, as well as pose extreme safety risks for utility crews and the public. Poles are frequently exposed to various severe weather conditions, and may become vulnerable to internal rot, decay, and infestation. These conditions, combined with the fact that approximately 25 percent of Toronto Hydro's wood poles are beyond their useful life as of 2017, make these poles more susceptible to failure. Approximately 11 percent of wood poles are already showing signs of material deterioration (as of 2017) and without intervention, this proportion is forecast to increase to 32 percent by 2024. Deteriorated and obsolete accessories such as porcelain insulators are susceptible to contamination build-up, which can lead to asset failure and pole fires. Through continued replacement of poles with porcelain accessories, Toronto Hydro has experienced success in limiting the number of pole fires (from 121 incidents in 2015 to 27 in 2017). Toronto Hydro plans to replace approximately 11,600 wood and concrete poles and associated accessories during the 2020-2024 period to reduce the aforementioned failure and safety risks.
- **Overhead Switches**: Overhead switches are constantly exposed to harsh environmental conditions. Their failure often leads to prolonged outages and can pose significant safety risks to utility workers if an arc flash happens during the switch failure. On average, overhead switches contribute to over 34,000 customer interruptions and 15,000 customer hours interrupted annually between 2013 and 2017. For 2020-2024, Toronto Hydro plans to replace a total of 692 overhead switches in renewal areas with a high concentration of end-of-life transformers in poor reliability.

The Program consists of both complete rebuild projects and spot replacements. Rebuild projects are executed in areas of poor reliability (with substantial concentrations of assets beyond useful life at a high risk of failure) or high volumes of transformers at risk of containing PCBs. Targeted rebuild areas with 4.16 kV or 13.8 kV distribution systems will also be converted to 27.6 kV. Outside of the rebuild project areas, any identified materially deteriorated poles or transformers beyond useful life and at risk of containing PCBs will be replaced through spot replacements.

The objectives of the Overhead System Renewal program for the 2020-2024 rate period are to:

- Renew deteriorated assets that are at or past their useful life to reduce failure risks;

- Maintain overall system reliability and improve reliability for certain poorly performing parts of the overhead distribution system; and
- Address the environmental risks of potential PCB oil spills by replacing transformers containing or at risk of containing PCBs.

E6.5.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's objectives and obligations to connect low and high voltage customers within 5 and 10 business days respectively at least 90 percent of the time (pursuant to the OEB's new connection metrics and section 7.2 of the Distribution System Code ("DSC")), by increasing overhead system capacity through voltage conversion from 4 kV and/or 13.8 kV to 27.6 kV in specified areas.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (as measured via metrics like SAIFI, SAIDI, FESI-7, System Health (poles)) by: ○ maintaining current levels of HI4 and HI5 condition poles over the 2020-2024 period; ○ reducing the on-going backlog of deteriorated poles by replacing approximately 11,600 poles known to be in HI4 and HI5 condition ○ reducing the on-going backlog of pole- top transformers past their useful life through area rebuild and spot replacement
Environment	• Contributes to improving Toronto Hydro's Spills of oil Containing PCBs measure, and environmental objectives and obligations by eliminating all equipment containing, or at risk of containing, PCBs from the overhead distribution system by the end of 2024, which would prevent the environmental impacts of possible PCB oil spills and potential breach of applicable environmental requirements (e.g. PCB Regulations SOR/2008-273 under the *Canadian Environmental Protection Act*, the Ontario *Environmental Protection Act*, and Toronto Municipal Code, Chapter 681 Sewers).

E6.5.3 Drivers and Need

Table 3: Drivers and Need

Trigger Driver	Failure risk
Secondary Driver(s)	Environmental Risk

The Overhead System Renewal program focuses on replacing three types of assets: (i) pole-top transformers; (ii) poles and accessories; and (iii) overhead switches. This renewal program is driven by the risk and impact of overhead distribution asset failures on system reliability and safety due to accelerated asset condition degradation resulting from factors such as: sustained exposure to dirt, salt, dust, moisture and humidity, and assets approaching end of their useful life.

Asset failures on Toronto Hydro's distribution system present reliability risks (which can lead to outages and directly impact customers), environmental risks (e.g. oil spills into the environment), and safety risks (e.g. stemming from electrical contacts, arc flashes, and potentially catastrophic fires). Timely replacements are required to avoid the distribution system being operated under contingency conditions (i.e. with interrupted feeders or assets that cannot provide backup supply in the event of a subsequent outage).

Without capital renewal, the risk of overhead asset deterioration and failures would worsen, resulting in more frequent and longer outages (declining SAIDI and SAIFI) and an increasing amount of reactive replacement work. Figure 1 shows the volume of reactive capital work requests generated to address overhead system related deficiencies between 2013 and 2017. On average, about 550 such work requests were initiated annually over that period. Timely replacement of aged and deteriorated equipment before failure can effectively mitigate the frequency and duration of interruptions experienced by customers.

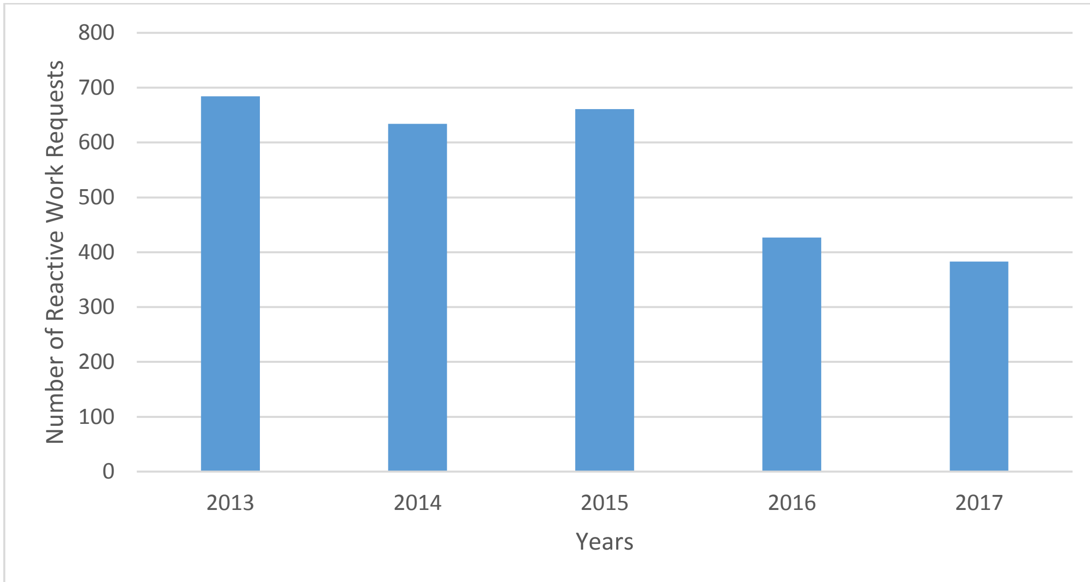


Figure 1: Reactive Work Requests to replace Overhead Assets from 2013-2017

The reliability outcome of historical investments in the Overhead System Renewal program is illustrated in Figure 2. As shown, customers interrupted ("CI") and customer hours interrupted ("CHI") resulting from overhead equipment failures have on average improved over the last two years.

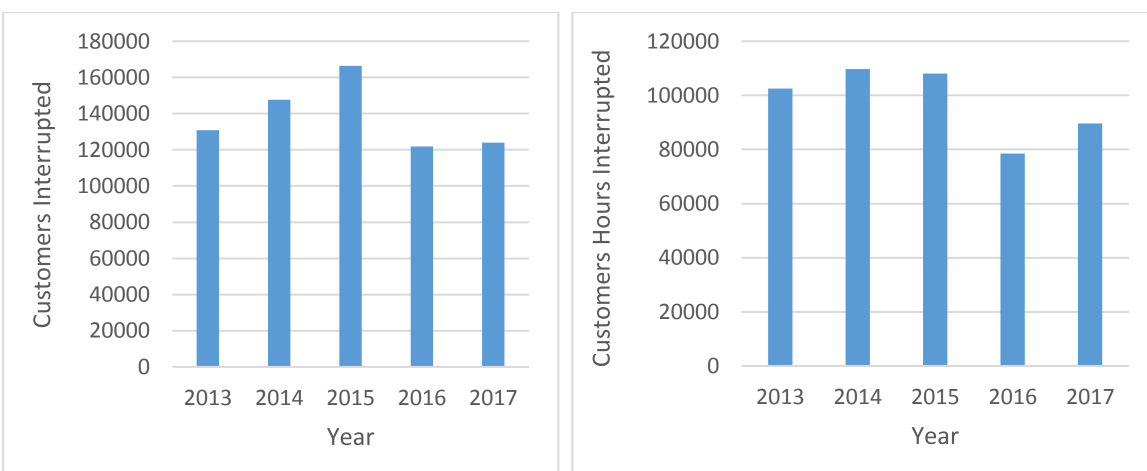


Figure 2: CI (Left) and CHI (Right) on the Overhead System (2013-2017)

Although historical investments have improved the overall reliability of the overhead system, Toronto Hydro must maintain and even increase the current renewal pace to sustain these improvements. This is necessary to address the large number of overhead assets that are expected to deteriorate in the coming years as they approach the end of their useful life or remain in service well beyond it. Table 4 summarizes the age demographics for poles, transformers and switches in 2017 and by 2024 (assuming the Overhead System Renewal program is not undertaken).

Table 4: Useful Life ("UL") of Overhead Assets

Asset Category	Asset Type	Typical Asset UL (years)	Assets past UL as of 2017 (%)	Assets past UL in 2024 without the Program (%)
Poles	*Wood*	45	25	29
	Concrete	45	20	22
Transformers	*Overhead*	35	14	40
Switches	*Gang Operated Load Break*	40	2	4
	In-line Disconnect	45	27	30

Table 5 shows the condition of Toronto Hydro's poles in 2017 and by 2024 (assuming the Overhead System Renewal program is not undertaken).

Table 5: Condition Data for Wood Poles

Asset Condition Index	Condition of Poles as of 2017	Condition of Poles in 2024 (Without Program)
HI1 – New or Good Condition	64979	57213
HI2 – Minor Deterioration	5210	8310
HI3 – Moderate Deterioration	20542	3596
HI4 – Material Deterioration	14371	17935
HI5 – End-of-serviceable Life	602	18650

Through a combination of spot replacements and complete rebuilds of areas with poor reliability and large concentrations of high-risk assets, Toronto Hydro plans to replace approximately 6,500 overhead transformers, 11,500 poles and 700 switches over the 2020-2024 period. Any target area that still utilize 4.16 kV or 13.8 kV systems will be converted to 27.6 kV. Converting load to 27.6 kV would: (i) enhance power quality with less voltage drop for customers at the end of distribution lines; (ii) reduce line losses, improving the efficiency of the distribution system; and (iii) enable the eventual decommissioning of Municipal Stations, avoiding operating and maintenance expenditures that would otherwise be incurred.

E6.5.3.1 Replacement of Overhead Transformers

Through the Overhead System Renewal program, Toronto Hydro replaces overhead transformers beyond useful life, which are at risk of failing and potentially posing environmental risk due to oil leaks that may contain PCBs. There are currently 29,628 overhead transformers in Toronto Hydro's distribution system.

As a critical component of Toronto Hydro's overhead system, transformers are used to step down primary distribution voltage to levels required to supply residential and commercial customers. They are mounted on poles and consistently exposed to external elements that cause degradation (e.g. weather conditions, dust, salt, moisture, cyclical loading, faults and humidity). In particular, exposure to precipitation and humidity over time causes corrosion (tank perforation) which can lead to oil leakage into the environment. Figures 3 and 4 show the reactive work requests to replace failed or severely deteriorated pole-top transformers and associated outages during the 2013-2017 period.

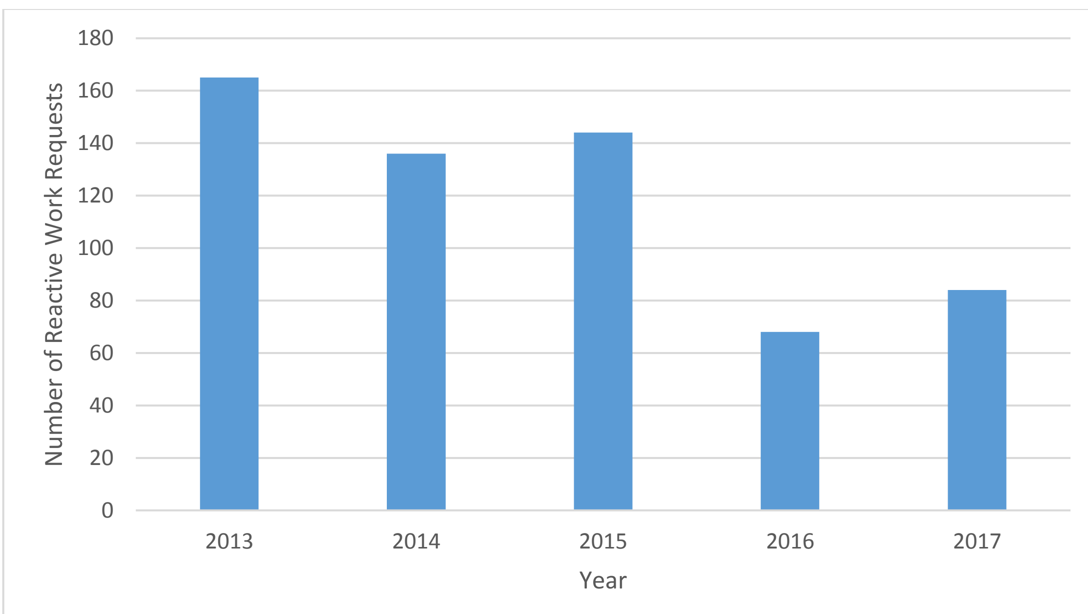


Figure 3: Work Requests for Pole-top Transformer Replacement

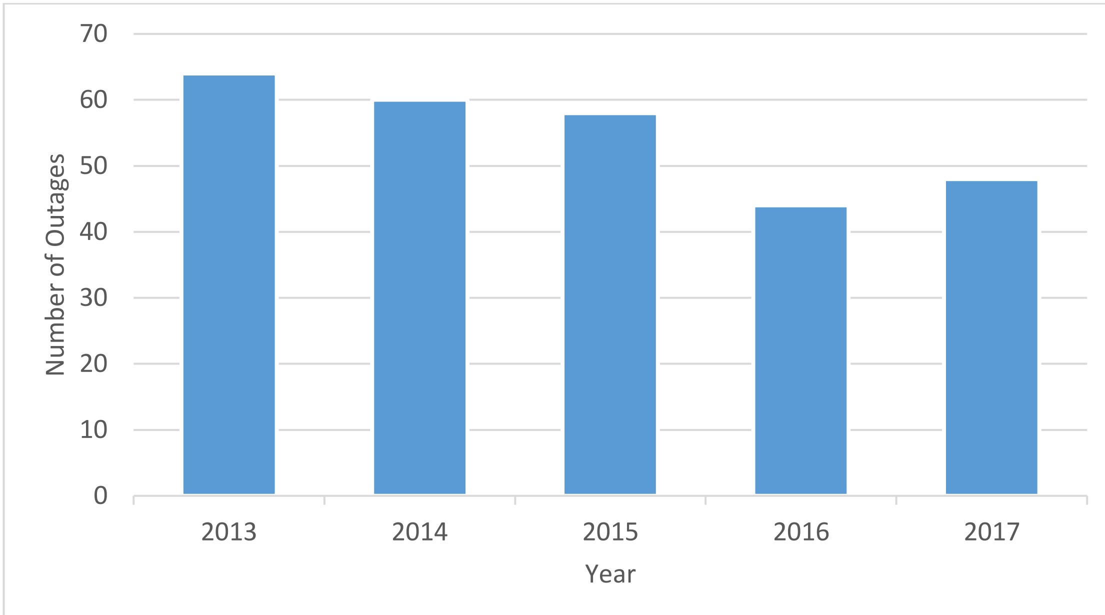


Figure 4: Forced Outages for Pole-top Transformers

Although on-going renewal work has contributed to the overall decline in reactive work requests since 2013, more than 80 requests were still made in 2017 (compared to over 60 in 2016). The vast majority of requests relate to transformer failures (approximately 40 to 70 failures per year), contributing to over 10,400 customers interrupted and 6,100 customer hours interrupted over the same period (see Figure 5).

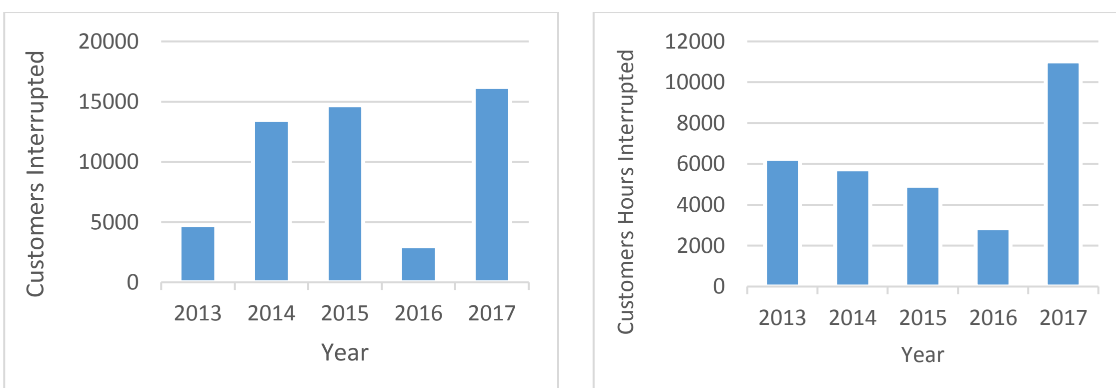


Figure 5: CI (Left) & CHI (right) for Pole-top Transformers

As part of Toronto Hydro's Quality Program, the organization investigated 145 failed overhead transformers between 2013 and 2017 to identify root causes of failure. The investigations found that

37 percent of the failed overhead transformers failed at or past the end of their useful life and that the number of failures increased with transformer age (see Figures 6 and 7). This shows that transformers on Toronto Hydro's distribution system which are at or past their useful life of 35 years are subject to an increased risk of failure.

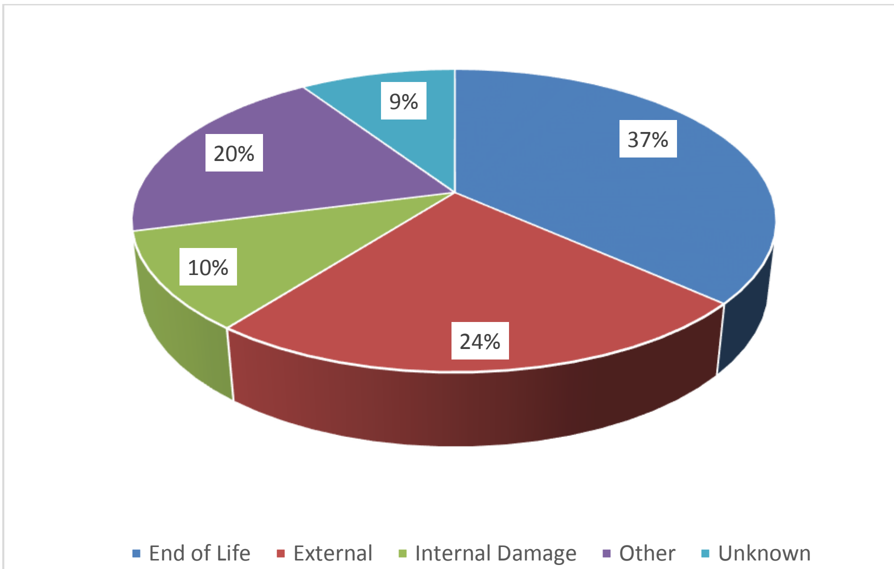


Figure 6: Root Cause Distribution for Failed Overhead Transformers from 2013-2017

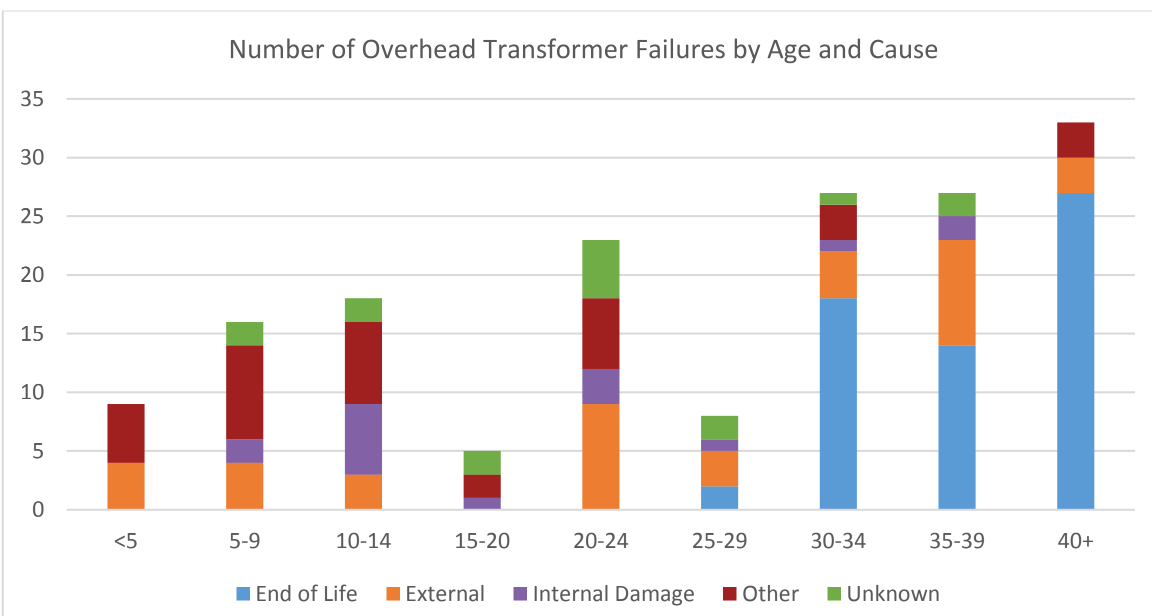


Figure 7: Age Distribution for Failed Overhead Transformers investigated 2013-2017

Figure 8 shows the current age distribution of overhead transformers and what it will be in 2024 without any replacement. As of 2017, 14 percent of overhead transformers had already reached or exceeded the end of useful life. A large number of transformers is also approaching their typical lifespan of 35 years. Without any replacement, this percentage will almost triple to 40 percent (or 11,285 units) by 2024. This drastic increase will exacerbate the risk of transformer failures and reverse the recent improvements in failure rates shown in Figure 3. Unless renewal is undertaken in a timely manner and at a sufficient pace, Toronto Hydro will face a growing backlog of transformers requiring replacement beyond 2024.

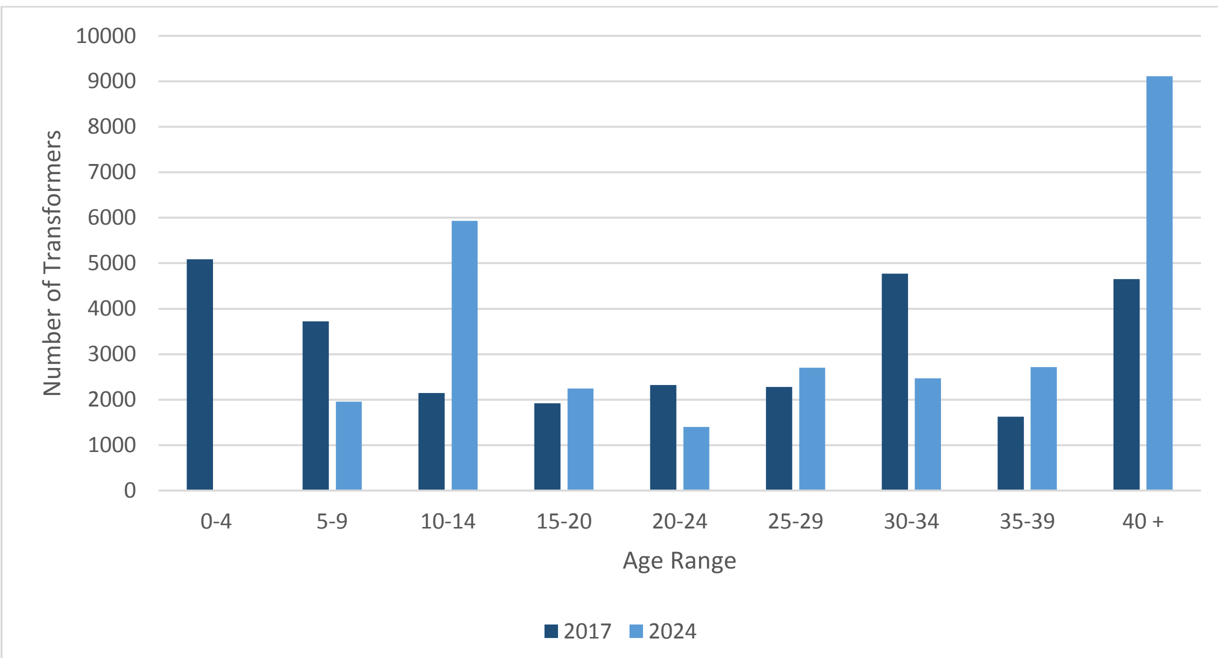


Figure 8: Age Distribution of OH Transformers in 2017 and 2024 (without investment)

A number of overhead transformer failures have also resulted in oil leaks into the environment. Figure 9 shows the total number of reported oil spill incidents for pole-top transformers during the 2013-2017 period. Older transformers are at an especially high risk of having oil containing PCBs. Given the failure risk of aged and deteriorated transformers, the potential for adverse effects on the environmental and affected community in the event of oil leaks is further heightened. Releasing oil containing PCBs (or oil on its own) into the environment may be a breach of the City of Toronto's Sewer Use By-Law, Ontario's *Environmental Protection Act* and, the federal *Canadian Environmental Protection Act* (including the PCB Regulations made thereunder). As the owner and operator of these transformers, Toronto Hydro could be held liable for any environmental impacts and/or ordered to perform remediation work under one or more regulatory regimes as the result of a single incident. A conviction or finding of non-compliance could also have serious reputational consequences for the utility.

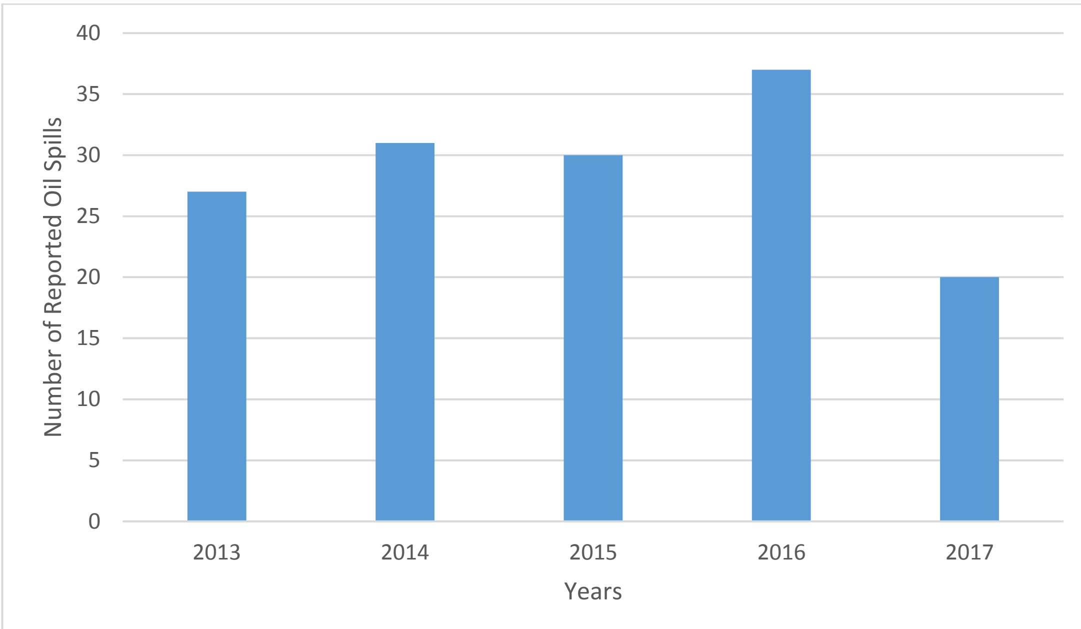


Figure 9: Number of Reported Pole-top Transformer Oil Spills

At the end of 2017, Toronto Hydro had about 6,400 overhead transformers that contain or are at-risk of containing PCBs. Toronto Hydro plans to replace most of these units (approximately 5,200) through the Overhead System Renewal program over 2020-2024. The remaining (approximately 1,200 units) will be replaced as part of the current Overhead System Renewal program prior to 2020 or through other capital programs (e.g. Area Conversions, Reactive and Corrective Capital) by the end of 2024. [2]

E6.5.3.2 Replacement of Poles and Accessories

Through the Overhead System Renewal program, Toronto Hydro also replaces wood and concrete poles showing material deterioration as well as deteriorating or obsolete overhead accessories such as porcelain insulators and non-standard animal guards. Over 40 percent of all forced outages on

[2] Exhibit 2B, Section E6.1 and E6.7

Toronto Hydro's overhead system (excluding animal and tree contacts) over 2013-2017 were due to poles or pole accessories.

Toronto Hydro has approximately 103,000 wood poles and 32,000 concrete poles in service. Poles are exposed to environmental conditions that reduce pole strength, including internal rot and decay at the ground line, shell rot, and infestation. Poles with reduced strength present operational risks to Toronto Hydro crews, safety risks to the public, and reliability risks to the overhead distribution system. The combination of severe weather and poles with reduced strength can lead to catastrophic failure scenarios where one failure can trigger cascading failures on a pole line (i.e. drop of multiple poles and associated equipment, hardware and conductor to the ground). Figure 10 shows the number of poles replaced reactively between 2013 and 2017.

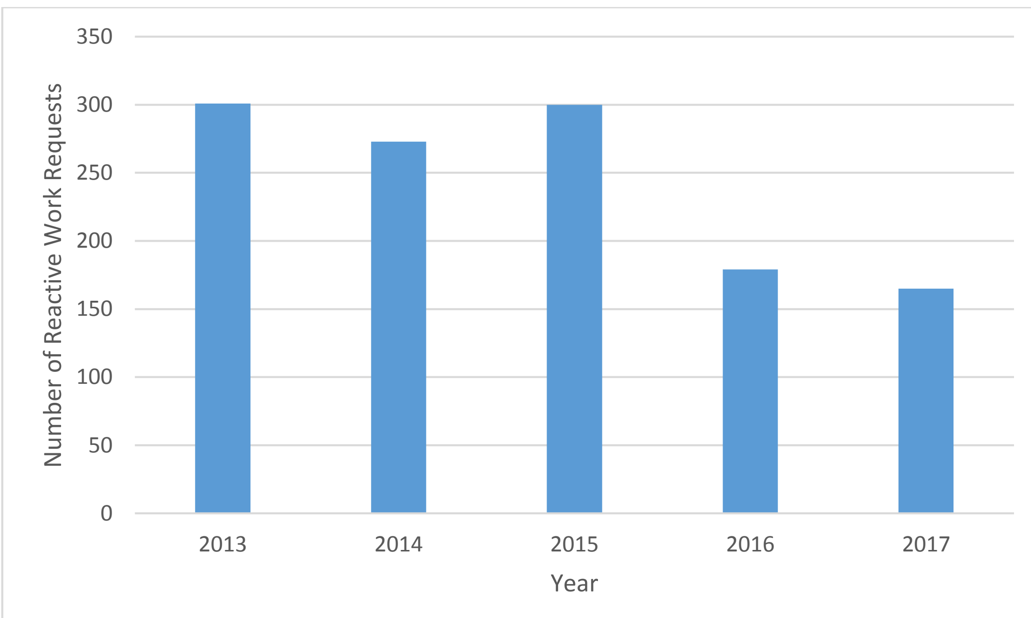


Figure 10: Reactive Work Requests for Pole replacement

In most cases, pole failures can lead to significant public safety risks and prolonged service disruptions. Poles contributed to 7,400 customer interruptions and 7,000 customer hours of interruption per year over the last five years. For these reasons, it is imperative that Toronto Hydro remains diligent and proactive in managing pole failure risks through pole replacements. Despite ongoing renewal, approximately 250 poles on average had to be replaced reactively per year between 2013 and 2017.

Figure 11 shows the age demographics of Toronto Hydro's wood and concrete poles (which have a useful life of 45 years) as of 2017. A significant number of poles on Toronto Hydro's distribution system have already passed their useful life.

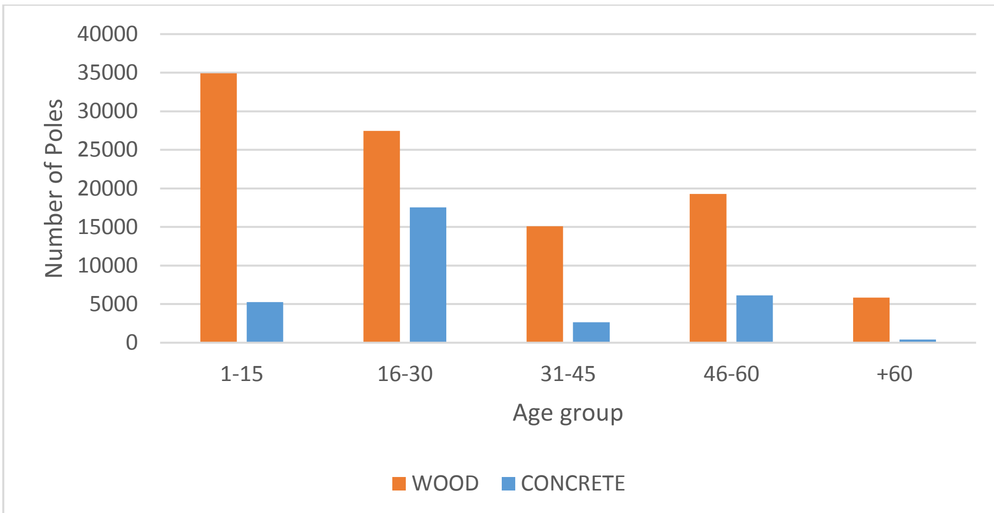


Figure 11: Age of Distribution of All Poles as of 2017

Based solely on age, an estimated 23 percent or 31,600 poles require immediate intervention to mitigate failure risk. However, Toronto Hydro plans to replace only aged poles in the worst condition (i.e. approximately 11,500 of the 31,600 aged poles) during the 2020-2024 period. The overall condition of poles is assessed through Toronto Hydro's pole inspection program. Asset Condition Assessment ("ACA") results indicate that as of 2017, approximately 11 percent of Toronto Hydro's wood poles (approximately 14,500) show signs of material deterioration (classified as HI4 and HI5), and 19 percent of wood poles (approximately 19,600) show signs of moderate deterioration (classified as HI3), as shown in Figure 12.

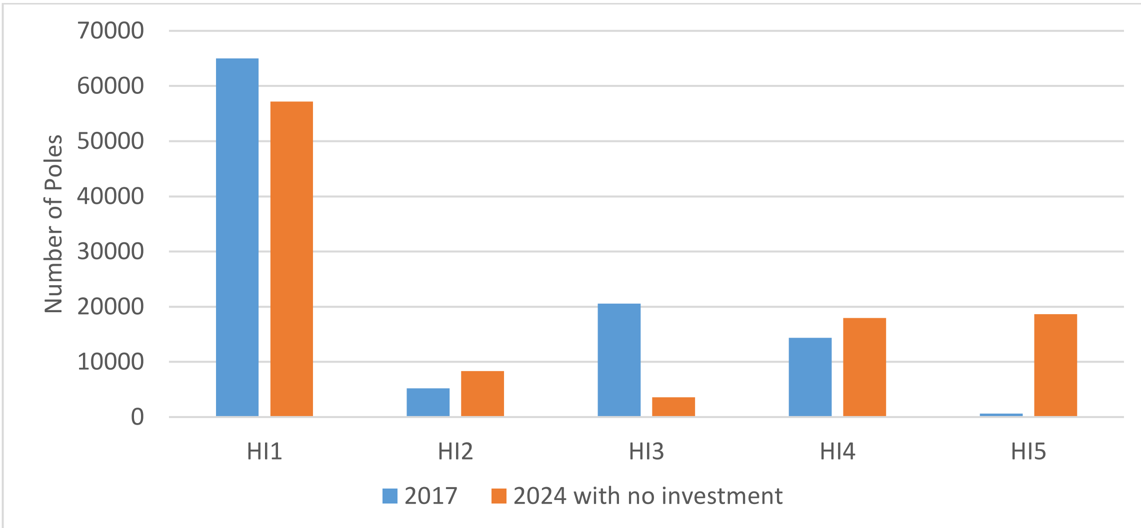


Figure 12: Health of Wood Poles as of 2017 and 2024 (without investment)

Replacement of poles with material deterioration will be carried out through overhead rebuild projects in areas with poor reliability and high concentrations of assets beyond useful life. The remaining units will be addressed by spot replacements.

In addition to replacing poles with material deterioration, the Overhead System Renewal program also replaces deteriorating and obsolete overhead accessories such as porcelain insulators, porcelain lightning arrestors and non-standard animal guards. Pole accessories were the single largest contributor to forced outages on the overhead system in 2013-2017. Toronto Hydro's legacy insulators are predominantly porcelain, which has been used in insulation for switches, lightning arrestors, terminators, and line post insulators. Porcelain insulators possess high dielectric strength and good mechanical properties, including hardness and resistance to chemical erosion and thermal shock. However, it is susceptible contamination build-up, and the accumulation of dirt and salt combined with moisture can lead to insulator tracking, flashover, cracks, insulator shattering and pole fires.

Table 6 shows the total number of pole fire incidents on Toronto Hydro's distribution system from 2015 to 2017. The number of pole fires from one year to the next can vary significantly as risks are related to weather conditions and the presence of contaminants (such as road salts and brines). The impact resulting from a high number of pole fires in 2015 demonstrated how disruptive such incidents can be for the distribution system. The decreasing trend of pole fire incidents is due to continued replacement of porcelain insulators with polymer insulators under the Overhead System Renewal program, and increased insulator washing under the maintenance programs.

Table 6: Pole Fire Incidents

Year	Number of Pole Fire Incidents
2015	121
2016	39
2017	27

E6.5.3.3 Replacement of Overhead Switches

The last category of assets replaced through the Overhead System Renewal program is overhead switches. Overhead switches are a critical component of the distribution system that facilitates the isolation of feeder sections or equipment for maintenance during interruptions for load shifting and other operating requirements. They also allow workers to operate safely by isolating feeder sections and creating zones that are free of energized equipment. Toronto Hydro uses two types of switches in its overhead system: in-line disconnect switches and gang operated load break switches, each of which further includes both manual load break switches and SCADA controlled switches. Currently there are 2,668 gang operated load switches and 4,951 in-line disconnect overhead switches on the overhead system.

Overhead switches are constantly exposed to harsh environmental conditions such as wind loading and salt spray. These switches can suffer either mechanical failure during operation or electrical failure via a flashover. Failed switches often lead to prolonged outages and pose significant risks to utility workers if an arc flash happens during switch failure. Figure 13 shows that more than 150 reactive work requests were initiated to address the defects found on switches in the overhead system between 2013 and 2017. Figures 14 shows that, despite recent improvement, overhead switches continue to contribute significantly to overhead customer outage frequency and duration. On average over the past five years, overhead switches contributed to over 34,000 total customers interrupted and 15,200 customer hours of interruption per year.

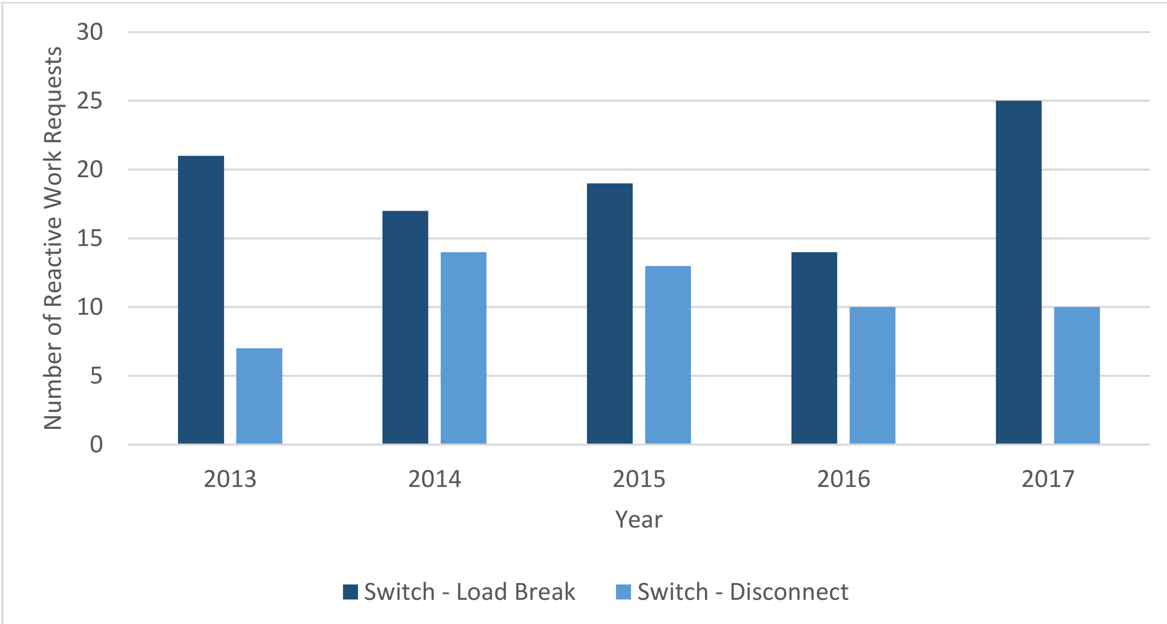


Figure 13: Reactive Work Requests for Switch Defects

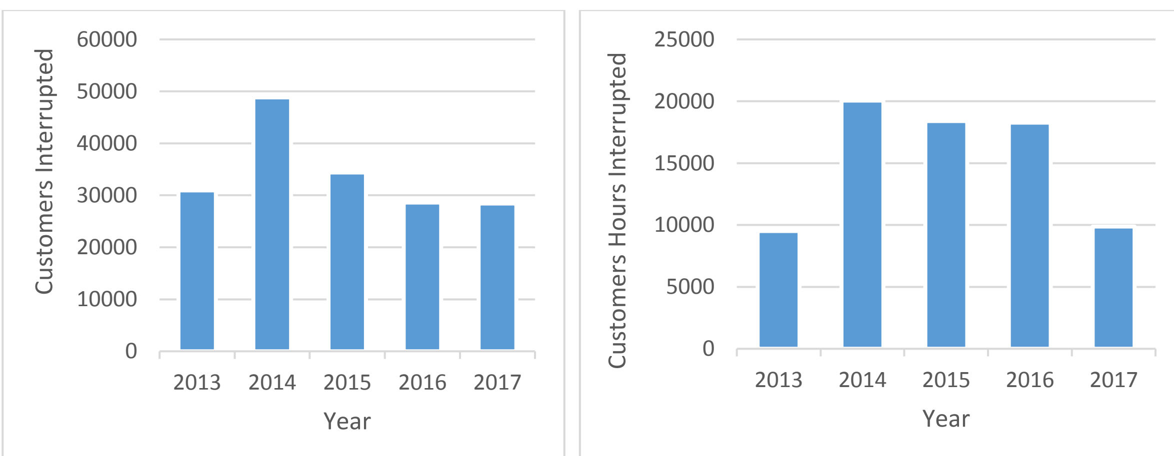


Figure 14: CI (Left) and CHI (right) by Switch Failures

Gang operated load break overhead switches have a useful life of 40 years while inline disconnect switches have a useful life of 45 years. Approximately 2 percent of gang operated switches and 27 percent of inline disconnect switches have reached their useful life as of 2017. Figure 15 shows the age demographics of Toronto Hydro's overhead switches in 2017. There is a considerable number of switches in service that are currently operating beyond their useful life. To maintain reliability, Toronto Hydro needs to continue its steady renewal of overhead switches to keep pace with the aging asset population and prevent an increase in failure rates.

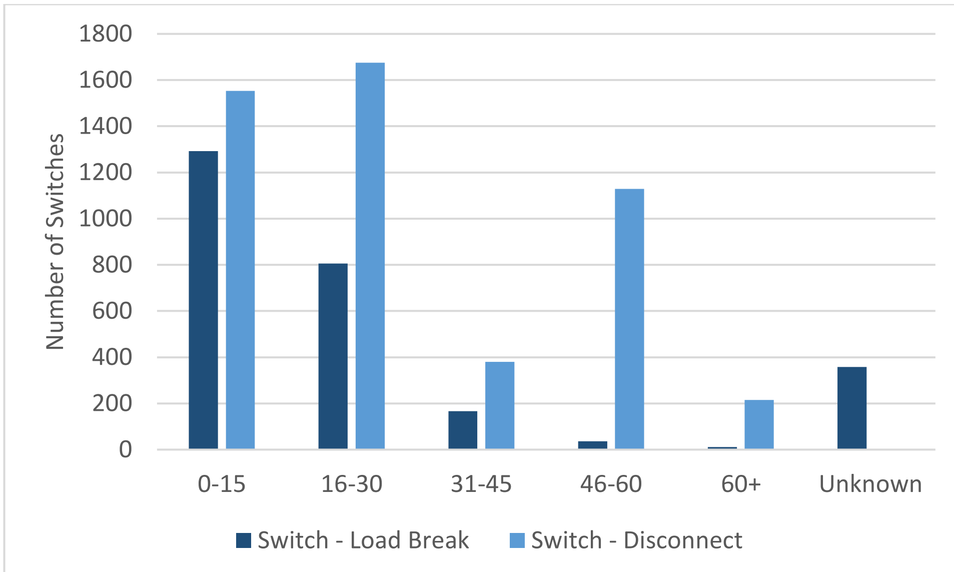


Figure 15: Overhead Switch Age Demographic

E6.5.4 Expenditure Plan

Table 6 provides the Historical (2015-2017), Bridge (2018-2019) and Forecast (2020-2024) expenditures for the Overhead System Renewal program.

Table 6: Historical & Forecast Program Cost ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Overhead System Renewal	61.0	51.0	35.7	18.4	17.8	49.8	50.4	51.3	56.5	57.7

E6.5.4.1 2015-2019 Expenditures

Toronto Hydro invested $148 million in the Overhead System Renewal program between 2015 and 2017, and expects to have invested $184 million by the end of 2019 (almost 25 percent higher than the 2015-2019 DSP forecast of $147.4 million). Table 7 shows the actual and forecast volumes of assets replaced over 2015-2019. During 2015-2016, work volumes and program spending were higher, primarily due to additional overhead renewal rebuild projects planned in 2014 and 2015 (to address declining reliability seen in 2013 and 2014) which continued into 2016. These investments have contributed to a steady improvement in reliability between 2015 and 2017.

Table 7: 2015 – 2019 Overhead Asset Replacement (Units)

Asset Class	Actual			Bridge		Total 2015-2019
	2015	2016	2017	2018	2019	
Poles	3656	2692	1513	1100	550	**9,023**
Transformers	940	769	441	575	290	**3,174**
OH Switches	192	167	120	55	35	**457**
Conductors* (km)	155	179	123	70	63	**527**

*Primary cables only

Overhead System Renewal spending was ramped down in 2017 through 2019 to accommodate the progression of certain other priority programs (e.g. Box Construction Conversion). Another factor contributing to cost variances is project scope adjustment as projects progressed from high level estimates to detailed designs. For example, designers may identify additional or fewer assets that should be included, scope changes due to interference with other utilities' works, or additional restoration costs.

E6.5.4.2 2020-2024 Forecasts

Toronto Hydro forecasts spending $265.7 million on the Overhead System Renewal program over the 2020-2024 period. This includes the cost of replacing end of life assets, converting the 4.16 kV and 13.8 kV distribution system to standard 27.6 kV lines, and renewing Overhead Street lighting assets deemed to be distribution assets.[3] The 2020-2024 forecast expenditures are based on the historical unit cost trends of major asset classes and the forecast volumes of major overhead asset replacements for the 2020-2024 period, as shown in Table 8.

Table 8: 2020-2024 Volumes (Forecast): Overhead System Renewal

Asset Class	2020	2021	2022	2023	2024	Total
Poles	2,230	2,230	2,220	2,400	2,450	**11,530**
Transformers	1300	1300	1300	1400	1400	**6,700**
OH Switches	130	130	130	160	160	**710**
Conductors* (km)	70	70	70	70	70	**350**

[3] See EB-2009-0180 et al Decision and Order dated February 11, 2010.

**Primary cables only*

The 2020-2024 forecast volumes are high level estimates based on a preliminary selection and scoping of areas targeted for complete rebuilds and spot replacements. Complete rebuilds include: replacing pole lines, overhead transformers and switches; upgrading associated overhead accessories; and re-stringing new conductor. Some of these areas are currently supplied by 4.16 kV and 13.8 kV systems, which will be converted to 27.6 kV through these projects. Once high level project scopes are produced, Toronto Hydro performs field inspections to validate the scope of work, identify third party conflicts and refine estimates before final design is completed. Through this process, projects identified for renewal are subject to change. For instance, poorly performing feeders that demonstrate higher risks than originally anticipated may take priority.

The 2020-2024 Program incorporates the three approaches described below.

- **Voltage Conversion:** Voltage conversion of feeders in areas with poor reliability and high concentrations of transformers containing (or at risk of containing) PCBs. Voltage conversion requires that all poles and transformers in each conversion area be replaced.
- **Feeder Rebuild:** Rebuild of feeders in areas with poor reliability and high concentrations of assets in deteriorated conditions that do not require voltage conversion.
- **Spot Replacement**: Spot replacement of transformers containing (or at risk of containing) PCBs and the worst condition poles not targeted in the first two categories as well as any legacy overhead accessories.

The complete rebuild approach is intended to minimize supply disruptions to customers where possible. Reduced disruption to feeders translates into fewer outages for customers and improved project efficiencies. Another way Toronto Hydro maximizes efficiency and cost savings during project planning is by breaking large overhead rebuild projects into smaller phases for enhanced manageability and coordination, providing greater flexibility for scheduling and assigning resources. This approach also reduces the number of scheduled outages and disruptions that customers will experience.

In addition, any voltage conversion overhead work will be coordinated with related stations maintenance work. This will allow feeders to be converted to 27.6 kV and for certain Municipal Stations to be decommissioned, thereby eliminating the need to replace and maintain substation equipment. There are additional costs as well as functional benefits from voltage conversions, including that the 27.6 kV distribution system transports more power over longer distances at lower losses (i.e. lower voltage drop at greater distances and improved power quality and distribution efficiency) than the existing 4.16 kV or 13.8 kV systems. This also results in fewer required substations, leading to fewer assets to maintain, lower expenditures and greater reliability.

E6.5.5 Options Analysis for Overhead System Renewal

E6.5.5.1 Option 1: Spot replacement of transformers, poles & switches in deteriorated condition, at or beyond their useful life

This option proposes to identify and replace only overhead transformers, poles and switches in deteriorated condition that: (i) are at or past the end of useful life; and (ii) contain or are at risk of containing PCBs. This is a short term mitigation option which focuses on renewing limited overhead assets (transformers, poles and switches) on a feeder segment, reducing the risk of PCB spills into the environment (through oil leaks) and the risk of outages due to asset failures.

This option can provide some improvement in limited circumstances where only a few assets on a feeder segment are in poor condition and eliminating these assets improves overall feeder performance. However, this option does not effectively renew aged or unreliable assets in the field, thus exposing the distribution system to equal or higher risk of asset failure leading to deteriorating reliability and safety to utility workers and the public. As a result of this approach, Toronto Hydro would likely incur higher reactive repair cost potentially with greater disruptions to the public and customers in the course of reactive repair work. This option is not recommended because it does not effectively address the underlying issue of system-wide overhead equipment failures.

E6.5.5.2 Option 2 (Selected Option): Proactive rebuild/ renewal of priority areas exhibiting degradation or poor reliability, voltage conversion, and spot replacement of higher risk transformers and poles.

This option proposes a rebuild or renewal of assets on feeders or geographical areas showing signs of degradation or progressively deteriorating reliability, spot replacement of transformers at risk of containing PCBs, and voltage conversion of functionally obsolete 4.16 kV or 13.8 kV primary voltage designs to 27.6 kV. Specifically, this option will include:

- Full rebuild of areas with poor reliability and a high volume of assets beyond their useful life;
- Full rebuild and voltage conversion in areas supplied by 4.16 kV or 13.8 kV primary voltage and with a history of poor reliability and a high concentration of assets beyond their useful life; and

- Like-for-like spot replacement of transformers which are beyond useful life and contain or are at risk of containing PCBs, poles showing material deterioration and associated overhead accessories.

In arriving at the decision to pursue this option, Toronto Hydro considered the need to strike a balance between maintaining acceptable safety and reliability on its overhead system, while providing electricity distribution services to customers at reasonable costs. Through this option, Toronto Hydro would be best able to manage the failure risk of overhead assets (i.e. by removing aged and unreliable assets to address deteriorating reliability) while also mitigating the environmental risks stemming from transformers at risk of containing PCBs (i.e. by removing them from service). Further, this option will prevent the accumulation of a large backlog of overhead assets at a high risk of failure and in need of replacement beyond 2024, which would reduce reliability and increase costs for customers over the long term.

E6.5.5.3 Option 3: Replace all transformers at risk of containing PCBs, all assets in deteriorated condition (or beyond useful life) and/or convert all 4.16 kV service areas to 27.6 kV

Under this option, the preferred option 2 would be expanded in one or more of the following ways:

- Replace all poles (approximately 36,000) that will reach end of useful life by 2024 (i.e. not just those in the worst condition).
- Replace all transformers beyond useful life, including those not at risk of containing PCBs. This would require replacing over 11,000 overhead transformers by 2024.
- Replace all overhead switches beyond their useful life (approximately 1,600).
- Convert all 4.16 kV service systems to 27.6 kV, which would require rebuilding 333 additional feeders and replacing approximately 1,800 transformers and 11,000 poles, which have not yet reached the end of their useful life.

Taking any of the above actions would provide additional reliability and other benefits such as reducing safety risks or improving system efficiency. This option would also ensure Toronto Hydro would have no backlog of end of life assets by 2024 and that none of the areas in the overhead system will be supplied by 4.16 kV. This is expected to reduce the number of failures on the overhead system, improving reliability and reducing the spending and resources required for reactive replacements and for overhead system renewal beyond 2024. Additional voltage conversion would improve power quality and efficiency, reduce line losses and accelerate decommissioning of certain municipal stations. However, Toronto Hydro does not consider this to be an economically feasible option at an estimated total cost of $850 million.

E6.5.6 Execution Risks & Mitigation

Large overhead renewal projects can be complicated given that third parties could also be doing work in the same area, resulting in potential conflicts and leading to incremental costs and delays. To ensure effective coordination with the City and other utilities, Toronto Hydro participates in the Toronto Public Utilities Coordinating Committee forum.

Other execution risks associated with large overhead rebuild projects include:

- **Third Party Attachments**: Where third party attachments to Toronto Hydro assets will be affected as part of the project, the relevant owners must be contacted to explore alternative attachment options which may delay the execution timeline. To mitigate this risk, Toronto Hydro will engage owners of these third party attachment assets as soon as possible to coordinate and plan the required transfer.
- **Permitting**: Delays in obtaining permits from applicable authorities (e.g. the City of Toronto, Ministry of Transportation, CN railways and Hydro One) may require extra design time. To mitigate this risk, additional design time will be built into the schedule to ensure the necessary permits are obtained without material effect on project schedule. Also, Toronto Hydro will work closely with the City of Toronto on planned road work through meetings of the Public Utilities Coordinating Committee. If work planned by the City puts Program completion at risk, Toronto Hydro will negotiate with the City to coordinate a construction schedule that is acceptable to all parties involved.
- **Operational risks**: Load transfers can be restricted in certain months of the year due to high usage of electricity (e.g. during the summer months). Toronto Hydro will mitigate this risk by scheduling work to avoid periods of loading restrictions.
- **Resource availability**: Insufficient resources can seriously impact project execution, resulting in delays or deferrals into future years. To address this risk, engineering work plan meetings are held each year as part of the new Enterprise Project Management process to ensure sufficient resources are available to complete the approved projects for that year.
- **Conformance with standards:** Toronto Hydro designs and constructs new overhead rebuild projects in accordance with applicable standards and specifications that are intended to ensure public and employee safety. However, unique situations can sometimes arise to

hinder design or construction in compliance with applicable standards. Identifying and making efforts to accommodate and address these issues during the planning and design stages can mitigate most of these risks. Toronto Hydro has established processes to address potential deviations from standards to ensure that the design and construction processes are not delayed and that any accepted deviations from standards do not impact the utility's ability to remain compliant with applicable requirements (including Ontario Regulation 22/04 - Electrical Distribution Safety).

E6.6 Stations Renewal

E6.6.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 85.3	**2020-2024 Cost ($M):** 141.5
Segments: Transformer Stations, Municipal Stations, Control and Monitoring, Battery and Ancillary Systems	
Trigger Driver: Failure Risk	
Outcomes: Reliability, Safety	

The Stations Renewal program (the "Program") manages stations-level failure risk through the replacement and refurbishment of end-of-life and obsolete assets. Station asset failure can result in power outages to thousands of customers for several hours or more, depending on the failure. Further, the lead time to replace station assets is often lengthy, with replacement of major assets such as transformer station switchgear requiring years to plan and complete. Hence, to meet customer expectations for reliability and system resiliency, Toronto Hydro's tolerance for failure risk in respect of station assets is low (relative to distribution lines assets). Predictive and preventative maintenance helps to maximize useful life, but in the absence of proactive renewal efforts, assets will eventually fail while in service. Toronto Hydro prioritizes station assets for proactive renewal based on age, condition, performance, load served, and customers connected, with the objective of maintaining reliability, minimizing cost impact to customers, and mitigating environmental and safety risks. Through this Program, Toronto Hydro's objective is to maintain current levels of stations reliability.

The Program is grouped into the segments summarized below and is a continuation of the station renewal activities described in Toronto Hydro's 2015-2019 Distribution System Plan.[1]

- **Transformer Stations ("TS"):** This segment involves the renewal of Toronto Hydro's switchgear, outdoor breakers, and outdoor switches located at TSs. The majority of Toronto Hydro's TS assets serve customers in the downtown core, where many customers are highly sensitive to power outages. During the 2020-2024 period, Toronto Hydro plans to replace five TS switchgears, nine TS outdoor breakers, and 61 TS outdoor switches, all at a total

[1] EB-2014-0116, Exhibit 2B, Section E6.13, E6.14, E6.15 and E6.19

estimated cost of $74.5 million. Replacing station assets that have deteriorated, are beyond their useful life, and subject to a heightened risk of failure allows Toronto Hydro to sustain current levels of reliability and mitigate crew exposure to safety hazards.

- **Municipal Stations ("MS"):** This segment involves the renewal of Toronto Hydro's switchgear and transformers located at MSs and their primary supplies. The majority of Toronto Hydro's MS assets serve Toronto's suburban areas which consist largely of residential and general service customers. During the 2020-2024 period, Toronto Hydro plans to replace 12 MS switchgears, 10 power transformers, 10 primary disconnect switches, and a MS primary breaker, at a total estimated cost of $37.7 million. Replacing these deteriorated and obsolete assets will allow Toronto Hydro to maintain the current level of MS reliability.
- **Control and Monitoring:** This segment involves the renewal of protection, control, monitoring, and communication assets at Toronto Hydro's TSs and MSs. During the 2020-2024 period, Toronto Hydro plans to install 6 new remote terminal units ("RTUs"), renew 39 existing RTUs (14 DACSCAN, 15 MOSCAD, and 10 D20 M++/ME), upgrade protections at 5 pilot-wire locations, and replace 45 kilometres of old copper control cable, all at a total estimated cost of $22.1 million. By replacing these obsolete and deteriorating assets, Toronto Hydro will be able to reduce outage durations and maintain overall stations reliability.
- **Battery and Ancillary Systems:** This segment involves the renewal of stations service equipment, DC battery and charger systems, and other supporting systems at Toronto Hydro's TSs and MSs. This segment also installs new systems to mitigate risks posed to and by equipment from flooding or fire susceptibility. During the 2020-2024 period, Toronto Hydro plans to install three sump pumps, replace 67 battery and charger systems, replace six station service transformers, and replace two air compressors at a total estimated cost of $7.3 million. Asset replacement is due to factors including old age, poor condition, obsolescent technology, and PCB contamination. This work will allow Toronto Hydro to maintain station integrity and system reliability for Toronto Hydro customers.

Toronto Hydro plans to invest $142 million in the Stations Renewal program in 2020-2024, which is an increase over the projected 2015-2019 spending in this Program (including forecasted inflation). This level of investment is necessary to address the backlog of high priority station assets that are at or beyond their useful life, have deteriorated in condition, and pose heightened failure risks. Given the necessity of an increased expenditure plan for Stations Renewal, Toronto Hydro has taken several steps to mitigate potential execution risks to the proposed 2020-2024 Program. These steps include increasing the use of contracted Stations design and field personnel, training and expanding the use of Toronto Hydro Stations internal resources, improved coordination with external parties and improvements in our downtown feeder outage coordination process. These improvements will address resources constraints and other risks associated with executing this increased capital investment in Toronto Hydro Stations assets. An in-depth discussion of execution risks mitigation is provided in Section E6.6.6.

E6.6.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, System Capacity) by
	  ○ reducing the percentage of station assets in deteriorated condition and operating beyond their useful life
	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by mitigating the exposure to failure risk for approximately:
	  ○ 32,000 customers by replacing assets at and beyond useful life at Transformer Stations (e.g. switchgears, outdoor breakers, outdoor switches);
	  ○ 25,600 customers by replacing assets at and beyond useful life at Municipal Stations (e.g. switchgears, power transformers, primary disconnect switches);
	  ○ 160,100 customers by renewing functionally obsolete protection, control, monitoring and communication assets; and
	  ○ All customers supplied from 15 TSs and 60 MSs by renewing station service equipment (e.g. sump pumps, battery and charger systems)

Safety	• Contributes to Toronto Hydro's public safety performance (as measured by the OEB distributor scorecard safety metrics) and employee safety (as measured via Total Recordable Injury Frequency) by: ○ Increasing the population of arc-flash resistant TS and MS switchgear resulting in improved worker safety and reduced risk of serious injury; ○ Decreasing the population of oil-filled TS outdoor breakers thereby reducing the risk of oil explosions causing equipment damage and injury.

E6.6.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Functional Obsolescence

The Stations Renewal program addresses failure risk and obsolescence issues associated with Toronto Hydro's highly critical stations assets. A significant portion of Toronto Hydro's station assets are operating beyond their typical useful lives and are subject to an increased risk of failure due to their age and condition. Station asset failures can have high consequences and impact due to the large number of customers served by each station. Often, necessary repairs are complex and require long lead times.

Like distribution line assets, prudent management of station assets is achieved by monitoring asset conditions and demographics. Unlike some distribution line assets however, asset management strategies that include just-in-time asset replacement are generally unacceptable for station assets.

In addition to their increasing failure risk, many older assets are built on technology that has become obsolete due to advancements and other emerging industry trends, and evolving best practices related to safety, customer needs, and functionality. Replacing obsolete assets allows Toronto Hydro to meet public policy and legal requirements (e.g. PCB elimination), accommodate increasingly more sophisticated customer needs (e.g. connection of distributed generation), operate its system more efficiently, and provide increased value to customers.

E6.6.3.1 Transformer Stations ("TS")

Toronto Hydro's TSs supply power to all classes of customers. Major TS assets include TS switchgear, TS outdoor breakers, and TS outdoor switches. A large portion of these assets are operating beyond their useful life and are consequently subject to heightened failure risk. Toronto Hydro uses a risk-based approach to identify the highest priority TS assets for replacement, with the objective of cost-effectively sustaining current levels of reliability and prudently mitigating crew exposure to safety hazards.

1. TS Switchgear

As shown in Table 4 below, by the end of 2019, about a quarter of Toronto Hydro's TS switchgear will be operating past their useful life. Many of these assets are non-arc-resistant and have other obsolete design features that heighten safety risks for crews and the risk of collateral asset damage in the event of switchgear failure.

Table 4: Transformer Station Switchgear Demographics at end of 2019

Switchgear Construction	# of Assets	% of Assets Past Useful Life	Other Demographic Information	
			% of Non-Arc Resistant Switchgear	% of Switchgear with Obsolete Breakers
Metalclad	44	20%	68%	50%
Brick Structure	5	100%	100%	100%
GIS	2	0%	0%	0%
Total	51	27%	69%	53%

Toronto Hydro uses asset age, condition, and operational feedback to identify and prioritize switchgear requiring renewal. Switchgear are composed of many different parts. Each part has its own failure mode and useful life (often less than the 50 years attributed to the switchgear as a whole). Reactive repair and maintenance of individual parts are performed but become less prudent as components which cannot easily be replaced (e.g. bus bars, bus insulators, and miscellaneous control wiring) age and deteriorate.

Toronto Hydro applies infra-red hotspot scanning, and cable termination, connection, and cleanliness qualitative (visual) assessments to measure and assess the condition of switchgear. Major components inside the switchgear such as breakers are also assessed for condition on a per breaker basis. Until recently, Toronto Hydro used these measurements (excluding the breaker condition assessments) to derive a single health index ("HI") for switchgear. However, results have suffered in quality and reliability due to the limited number of measurements and difficulty in quantitatively balancing different indicators. As a result, Toronto Hydro evaluates these assets on an asset-by-asset basis rather than use a single HI metric. In this regard, Toronto Hydro considers switchgear age, breaker conditions and operational feedback its best indicators for risk assessment of these critical assets. The current age demographics of Toronto Hydro's TS switchgear units is shown in Figure 1 below.

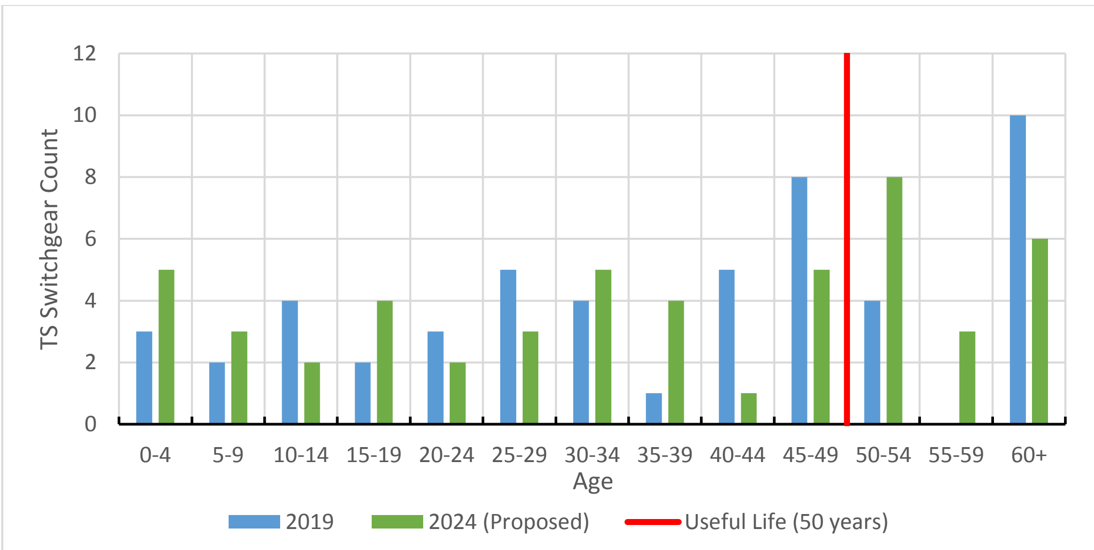


Figure 1: TS Switchgear Age Demographics

As indicated in Figure 1 above, Toronto Hydro will have 14 TS switchgear units operating at or beyond their useful life expectancy at the end of 2019 with an additional 8 more expected to be by 2024. Toronto Hydro's condition assessment for all breakers contained within its TS switchgear population is shown in Figure 2 below, which indicates that a significant proportion of Toronto Hydro's breakers with moderate or worse deterioration are air-blast breakers. Among Toronto Hydro's TS switchgear population, these are the oldest breakers in use and are found in 11 of the switchgear units operating beyond their useful life.

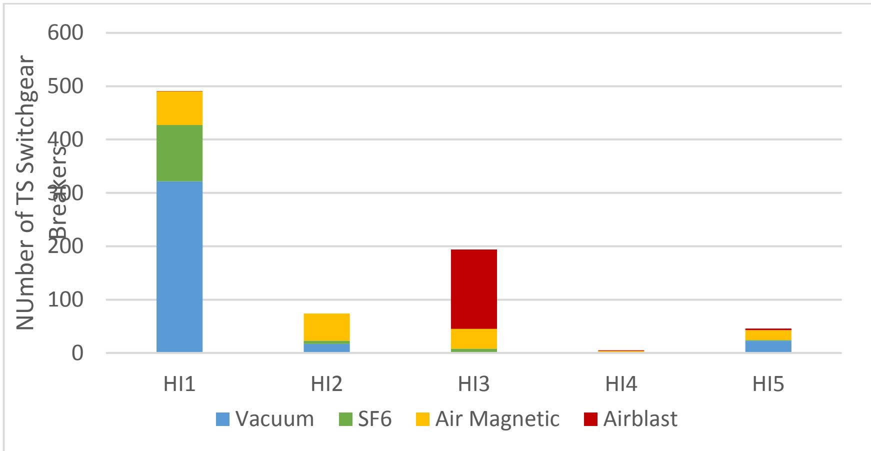


Figure 2: TS Switchgear Breaker Condition by Type as of 2017

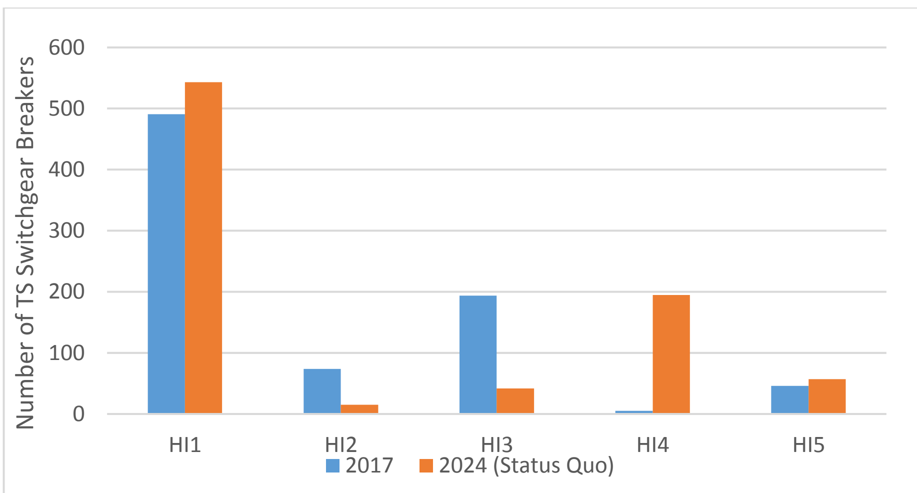


Figure 3: TS Switchgear Breaker Condition Aggregate as of 2017 and in 2024 Without Investment

The impact of switchgear failure is severe. As an example, a recent failure of a switchgear unit due to a failed insulator that flashed-over resulted in an interruption of 6,194 customers and 32 MVA of load. The average affected customer was without power for 9.5 hours while restoration of the last customers took 12 hours. A photo of the failed insulator is shown in Figure 4 below. As shown in this photo, visual condition assessment may not always be effective. In many cases, these components are not accessible for the level of inspection required to detect measurable signs of impending failure. This is particularly true for some metalclad switchgears that require a complete switchgear outage to enable thorough condition observations, which is not possible without significant customer outages given today's system loading.

Figure 4: Failed Switchgear Insulator – Imperfection Difficult to Observe

Toronto Hydro's average TS switchgear supplies 37 MVA of load – more than the failure case highlighted above – and its heaviest loaded unit alone serves 63 MVA of peak load. As shown in Figure 5 below, these assets primarily serve Toronto's downtown and adjacent areas, which include Toronto's financial district, entertainment district, university district, and some of the city's densest residential communities.

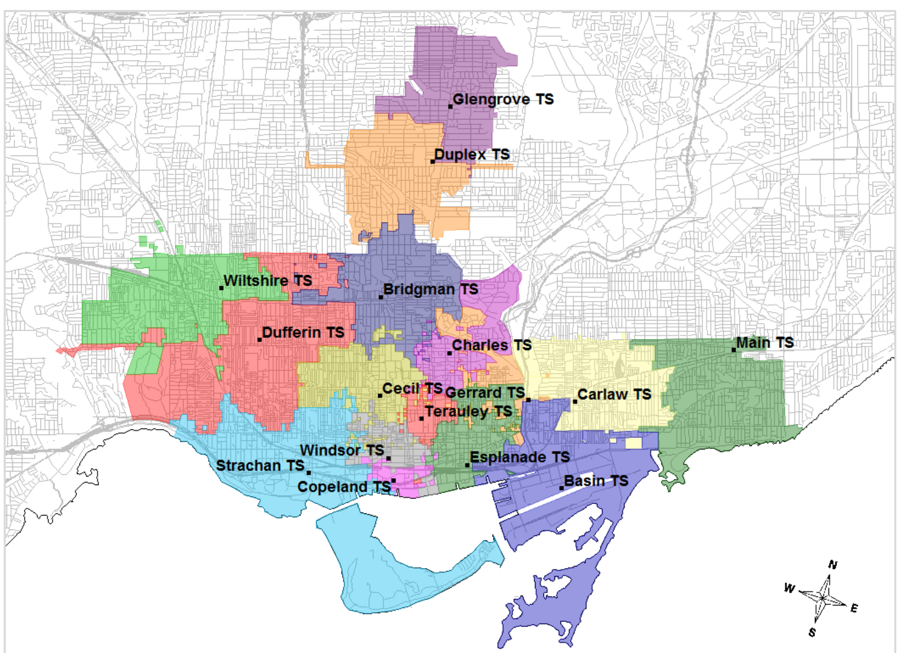


Figure 5: Location of TSs containing Toronto Hydro-Owned Switchgear (excluding Cavanagh TS in North Scarborough)

Toronto Hydro proposes to replace the five TS switchgear units identified in Table 5 below during the 2020-2024 period. All of the units proposed for replacement are beyond their 50-year useful life expectancy and feature obsolete circuit breakers contained within non arc-resistant enclosures. Condition assessments performed during breaker maintenance show that all of the breakers in the switchgear units proposed for replacement suffer from moderate or material deterioration as of 2017. Breakers are used to determine the condition of a switchgear because they are the "moving parts" inside switchgear and are generally indicative of a switchgear unit's overall health.

Table 5: TS Switchgear Proposed for Replacement

Station	ID	Enclosure	Breaker Type	2017 Condition Assessment (for Breakers)	Replacement Year
Strachan TS	*A5-6T*	Metalclad	Air Blast	Moderate Deterioration	2023
Carlaw TS	*A4-5E*	Brick	Air Blast	Moderate Deterioration	2022
Windsor TS	*A5-6WR*	Metalclad	Air Blast	Moderate Deterioration	2023
Duplex TS	*A1-2DX*	Metalclad	Air Magnetic	Moderate Deterioration	2023
Bridgman TS	*A1-2H*	Brick	Air Blast	Moderate Deterioration	2024

As shown in Table 6 below, with these replacements and investments, there will be a decrease in non-arc resistant switchgear and a decrease in switchgear with obsolete breakers compared to 2019 demographics (see Table 4) from 69 percent to 60 percent and 53 percent to 41 percent respectively.

Table 6: Transformer Station Switchgear Demographics at End of 2024 With Investment

Switchgear Construction	# of Assets	% of Assets Past Useful Life	Other Demographic Information	
			% of Non-Arc Resistant Switchgear	% of Switchgear with Obsolete Breakers
Metalclad	45	31%	64%	42%
Brick Structure	3	100%	100%	100%
GIS	5	0%	0%	0%
Total	**53**	**32%**	**60%**	**41%**

The Windsor TS (A5-6WR) switchgear unit is notable for its importance as a critical asset located in and supplying the city's downtown core. It was originally installed in 1956 and will be 63 years old in 2019. High loading on this switchgear combined with its age and condition contributed to the need for Copeland TS (installed under the Station Expansion program).[2] With Copeland TS online, Toronto Hydro will gain the capacity required to offload and replace the Windsor TS (A5-6WR) switchgear. This will provide increased reliability to 434 customers consuming 53 MVA of peak load, a very high ratio of average load per customer. Many of these customers are large commercial entities in high-rise buildings in the center of the city's financial district. Figure 6 below shows an overview of the volume of customers and quantity of load benefitting from Toronto Hydro's proposed replacement plan.

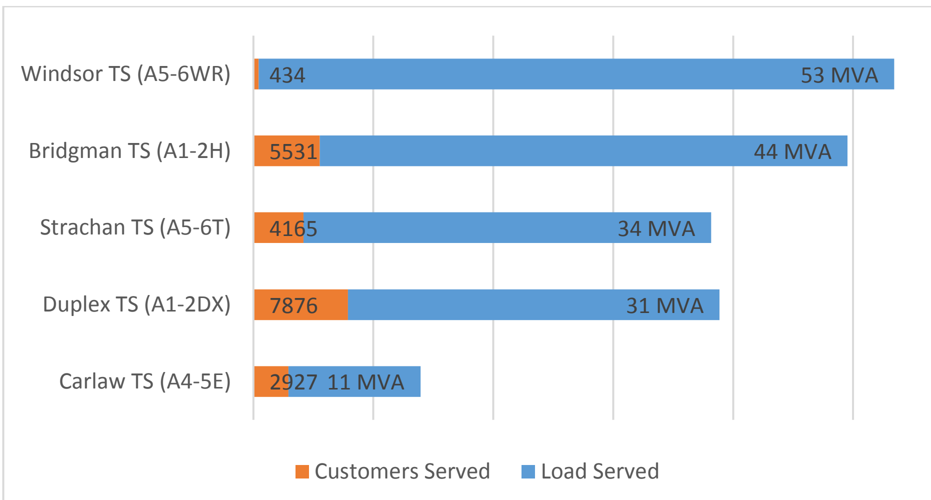


Figure 6: Customer Impact of Switchgear Failure - TS Switchgear Proposed for Replacement

When replacing TS switchgear units, Toronto Hydro installs fully-rated arc-resistant switchgear to utilize the available capacity of the supplying Hydro One transformer. Potential Hydro One transformation upgrades that could justify installing a larger capacity switchgear are considered in coordination with the Stations Expansion program.[3]

Arc-resistant switchgear is installed because it minimizes the safety risk posed to Toronto Hydro personnel presented by arc-flash events. An arc-flash event is a short-circuit inside a switchgear that causes an electrical explosion. If such an event occurs when personnel are switching or working on nearby switchgear that is not arc flash rated, the explosion and associated energy released can be life threatening. Arc-resistant switchgear, which has become an industry standard, is designed to

[2] Exhibit 2B, Schedule E7.4
[3] *Supra* note 2

contain the explosion, and re-direct the energy to reduce the risk of injury to anyone present within the station

2. TS Outdoor Breakers

As shown in Table 7 below, by the end of 2019, 4 percent of Toronto Hydro's TS outdoor circuit breakers will be operating past their 45-year useful life. About a quarter of these breakers (i.e. KSO oil circuit breakers) are based on obsolete technology and may contain oil with PCBs, which, in the case of a breaker failure, would increase the safety risk for crews, the risk of collateral damage to other assets, and the risk of environmental damage.

Table 7: TS Outdoor Breakers Demographics at the end of 2019

Outdoor Breaker Technology	# of Assets	% of Assets Past Useful Life	% of Assets with PCBs>2ppm
KSO Oil Circuit Breaker	20	20%	85%
SF6 Circuit Breaker	25	0%	N/A
Vacuum Circuit Breaker	45	0%	N/A
Total	90	4%	19%

As indicated in Table 7, by the end of 2019, 20 percent of Toronto Hydro's KSO oil-based circuit breakers will be past their useful life of 45-years and 85 percent will contain PCBs greater than 2 ppm (identified through sampling).

Figure 7 below shows the TS Outdoor Breakers condition as of 2017 and the condition of the breakers in 2024 without investment.

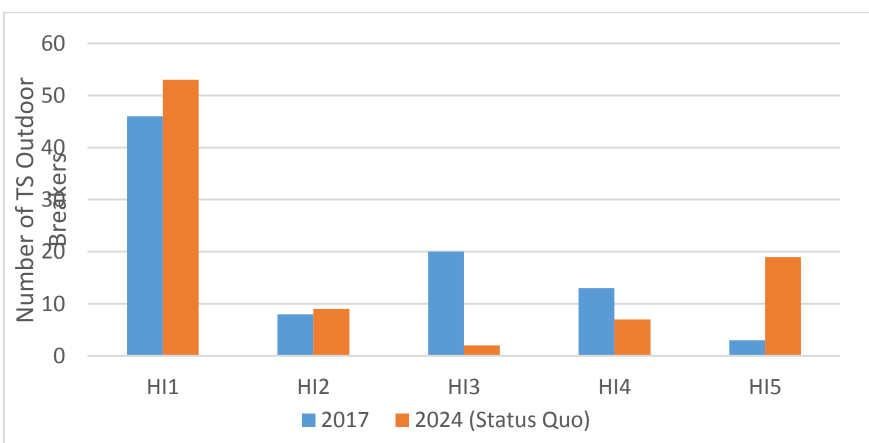


Figure 7: TS Outdoor Breaker Condition as of 2017 and in 2024 without investment

As of the end of 2017, condition observations of these KSO oil circuit breakers in particular show that approximately 55 percent are showing signs of moderate to material deterioration. Figure 8 below illustrates the condition of these circuit breakers at the end of 2017 (including the units planned to be replaced in 2018 and 2019).

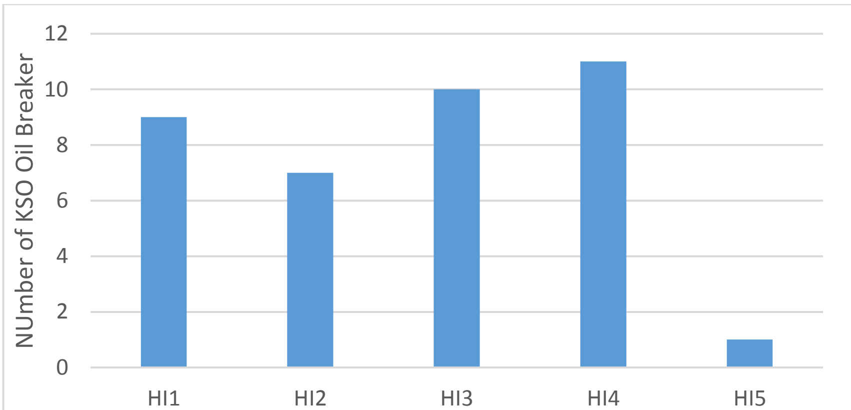


Figure 8: Condition Assessment for KSO Oil Circuit Breakers as of the end of 2017

KSO oil circuit breakers have not been manufactured or purchased by Toronto Hydro since the early 1980s. Recently, Toronto Hydro has had difficulty obtaining the spare parts required to properly maintain them. As shown in Figure 9 below, by the end of 2019, 4 TS outdoor breakers (all KSO oil circuit breakers) will be operating beyond their useful life of 45-years with an additional 9 that will be 45 years or older by 2024.

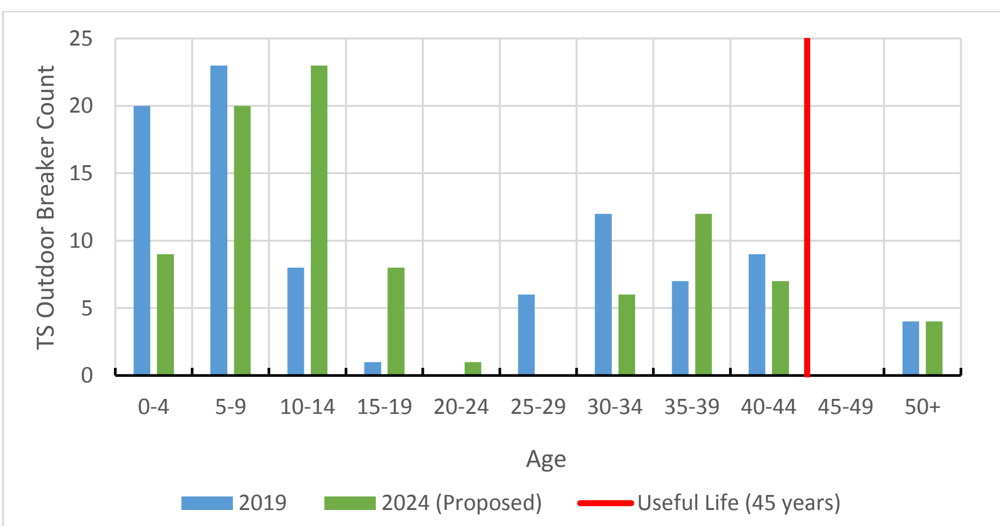


Figure 9: TS Outdoor Breaker Age Demographics at the end of 2019

The life of these breakers has been extended for as long as practical through corrective repair. This is done by obtaining parts for repair from retired units. As the in-service population of KSO oil circuit breakers continues to age and deteriorate, obtaining these spare parts has become less sustainable.

The failure risk of these circuit breakers is high and the impact is significant. When a breaker fails, thousands of customers will experience an outage – typically lasting one to two hours. Circuit breaker failure is most likely to occur when the breaker is triggered to operate. When a circuit breaker fails, the next upstream protection device at the station bus is triggered to operate. A fault that was otherwise localized on a feeder would then extend to all of the customers supplied by that station bus, potentially disrupting anywhere from 1,000 to 10,000 customers depending on the bus. Toronto Hydro recently experienced an outage of this nature when an outdoor breaker at Finch TS failed to open during a fault. The bus protection system was forced to operate, interrupting power to nearly 5,000 customers. Most customers were restored within one hour of the initial incident; however, all of those customers were supplied by feeders that would not have suffered an outage had the breaker operated as intended.

Beyond the outage impact to customers, KSO oil circuit breakers run the risk of failing catastrophically, wherein the circuit breaker explodes and sets fire to its oil, potentially damaging equipment, injuring personnel in the vicinity and impacting the surrounding environment. An example of such a failure recently occurred at Manby TS (owned by Hydro One). A snapshot of the resulting fire is shown in Figure 10 below. Similarly to the Finch incident, upstream protection was triggered and thousands of customers in the downtown west-end of Toronto suffered an outage lasting approximately three hours. Equipment surrounding the breaker also suffered collateral damage from the fire and the explosion. While no public or field personnel were injured during the incident, it highlights the inherent safety risk of using oil as an insulating medium in switching devices.

Figure 10: Catastrophic Failure of an Outdoor Circuit Breaker at Manby TS (Hydro One-owned)

In addition to heightened safety risk, there is also a risk of environmental damage due to oil leakage. Nearly all of Toronto Hydro's KSO oil circuit breakers contain PCBs.

To mitigate the safety risks noted above, Toronto Hydro plans to replace the 9 TS outdoor breakers identified in Table 8 below during the 2020-2024 period. These breakers have been selected using a variety of inputs including current condition assessment, asset age, projected condition in 2024, load served, and PCB content. All of the breakers proposed for replacement will be beyond their 45-year useful life expectancy and contain or at risk of containing oil with PCBs. For work to be done first during the 2020-2024 period, Toronto Hydro will prioritize the breakers presenting highest failure risk.

Table 8: TS Outdoor Breakers Proposed for Replacement

Station	Breaker Type	Feeder	Load Served	Replacement Year
Fairchild TS	*KSO Oil Circuit Breaker*	M10	7 MVA	2020
Leslie TS	*KSO Oil Circuit Breaker*	M26	11 MVA	2021
Finch TS	*KSO Oil Circuit Breaker*	M23	15 MVA	2022
Finch TS	*KSO Oil Circuit Breaker*	M26	16 MVA	2022
Leslie TS	*KSO Oil Circuit Breaker*	M29	15 MVA	2023
Leslie TS	*KSO Oil Circuit Breaker*	M30	15 MVA	2023
Leslie TS	*KSO Oil Circuit Breaker*	M32	10 MVA	2024
Bathurst TS	*KSO Oil Circuit Breaker*	M23	16 MVA	2024
Bathurst TS	*KSO Oil Circuit Breaker*	M32	14 MVA	2024

As per Figure 11, these assets are located at stations serving customers located in the North York area. Once this work is complete, customers and loads connected to these 5 stations will face reduced risk of power disruptions resulting from breaker failure.

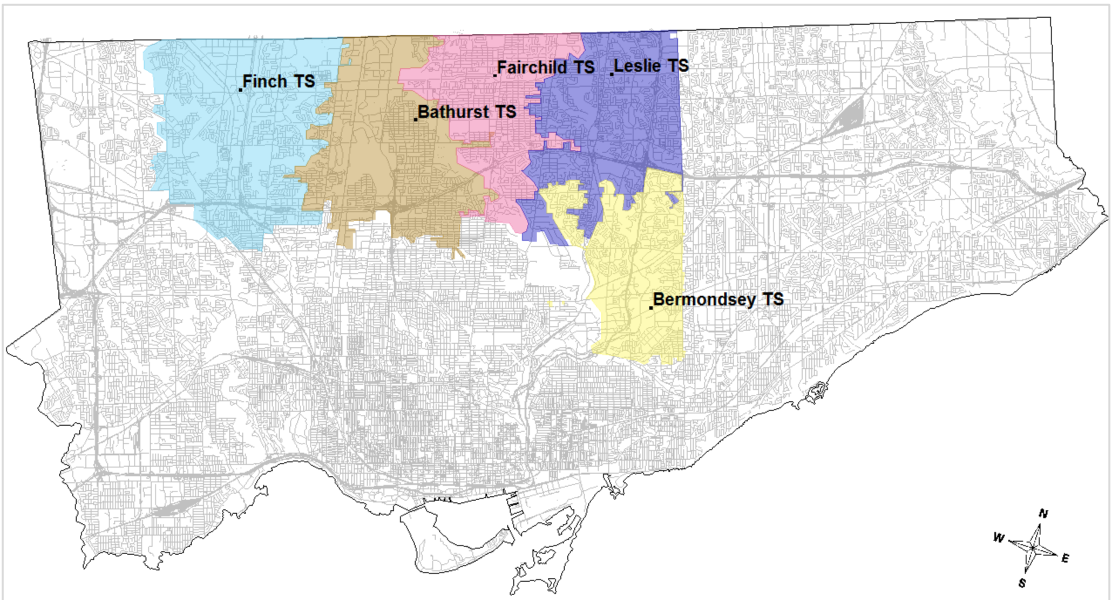


Figure 11: Toronto Hydro-owned TSs containing outdoor circuit breakers.

When replacing these KSO oil circuit breakers, Toronto Hydro installs new vacuum circuit breakers with modern protection systems. Vacuum breaker technology is more reliable, does not contain oil, and is effectively the industry standard for breakers of this class. By installing a modern protection system, Toronto Hydro would improve its ability to accommodate new customer connections such as renewable generation or energy storage systems. As such, this work will provide customers with increased reliability and flexibility in addition to eliminating some of the highest safety and environmental risks in the system.

3. TS Outdoor Switches

In addition to owning breakers at the five North York stations identified in Figure 11 above, Toronto Hydro also owns 225 TS outdoor switches located at the same stations. By the end of 2019, 31 percent of these TS outdoor switches will be operating beyond their 50-year useful life. The majority of them have never been replaced since their original switchgear or breaker installations.

Many of these switches have failed in recent years and their aged and deteriorated condition is beginning to show. For example, between 2004 and 2017, 26 defective equipment reports were recorded for these switches. This represents approximately 20 percent of the total deficiencies reported among all Toronto Hydro switchgear assets during the same period, despite these switches making up only 5 percent of the category[4].

Toronto Hydro does not have a Health Index for these switches as a result of their simple and discrete nature. Switches are manual devices that either open or close when operated. Therefore, their condition is best captured by relying on visual assessment by Toronto Hydro field personnel and their experiences operating these switches. In this regard, relevant personnel have noted difficulty operating these switches, citing that in many cases, excessive force is required to close or open them which can damage the switches and result in injuries to workers. The number of broken switches per year can be seen in Table 9 below, which summarizes the number of corrective repairs performed each year from 2007 to 2017. The average age of each switch at its time of repair was approximately 40 years old. Difficult to operate switches create safety issues. They may not operate fully as intended which can lead to risks such as arc-flash, thus increasing the risk to field personnel.

Table 9: TS Outdoor Switches Corrective Repairs and Maintenance

Reactive Repairs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
TS Outdoor Switch	1	6	2	2	2	1	3	1	5	2	1	**26**

As shown in Figure 12 below, by the end of 2019, 69 of Toronto Hydro's TS outdoor switches will be operating beyond their 50-year useful life, with an additional 17 by 2024. Without action during the 2020-2024 period, almost three quarters of Toronto Hydro's TS outdoor switches will be beyond or within 5 years of their useful life expectancy by 2024.

[4] For the purposes of defective equipment reporting, TS switchgear units, MS switchgear units and TS outdoor switches are all included in the same category.

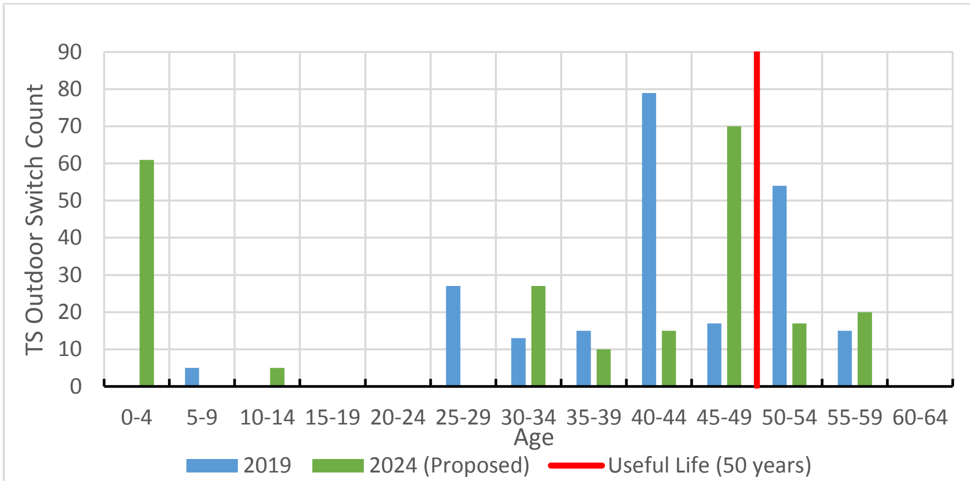


Figure 12: TS Outdoor Switch Age Demographics

Replacing or repairing outdoor switches can be very difficult as they are mounted on structures at the height of and in close proximity to other energized equipment (see example in Figure 13 below). Additionally, when a switch fails, the scheduling and contingency benefits that can be incorporated into a planned replacement are not available. Planned replacements are coordinated with other maintenance or capital work to minimize both switching operations and the risk of customer interruptions. However, when a switch fails, it may not be prudent to coordinate repairs with planned work, because until the switch is repaired the system is left in a state of compromised reliability, which presents the potential for lengthy outages.

Figure 13: Repair of TS Outdoor Switch

To reduce the risk of exposing customers to these periods of reduced reliability, Toronto Hydro plans to replace 61 TS outdoor switches during the 2020-2024 period as outlined in Table 10 below. All switches proposed for replacement will be beyond their 50-year useful life expectancy. Performing this work will reduce the risk of lengthy disruptions for customers served by three TS stations located in North York: Bathurst TS, Leslie TS and Bermondsey TS.

Table 10: TS Outdoor Switches Proposed for Replacement

Station	Feeder Tie Switch	Line Disconnect Switch	Bus Disconnect Switch	Total Switches	Replacement Year
Bathurst TS	1	2	0	3	2020
Leslie TS	1	2	0	3	2021
Bermondsey TS	1	2	0	3	2021
Bathurst TS	2	4	0	6	2021
Leslie TS	2	4	0	6	2022
Bermondsey TS	1	2	0	3	2022
Bathurst TS	1	2	0	3	2022
Bathurst TS	0	0	18	18	2023
Leslie TS	0	0	6	6	2024
Bermondsey TS	0	0	10	10	2024
Total	**9**	**18**	**34**	**61**	-

E6.6.3.2 Municipal Stations ("MS")

Toronto Hydro's MSs supply power to residential and general service customers. Major MS assets include switchgear, power transformers, primary disconnect switches and primary circuit breakers. A large portion of these assets are operating well beyond their useful life and are consequently at a heightened risk of failure. Work proposed under this segment will maintain the current level of reliability for MS-supplied customers by replacing deteriorated and obsolete assets at MSs with no foreseeable voltage conversion plans.

The purpose of an MS is to step down voltage to distribution levels and to provide a supply point for distribution feeders. Because the major assets in an MS are connected serially, power flow to customers is interrupted when any of the station's assets fail. For this reason, all end-of-life assets in the segment can be considered to have equal importance in maintaining overall MS reliability.

An MS supplies hundreds to thousands of customers. If any of a station's major assets fail, then all connected customers will experience a power outage. Power is restored to customers by switching their supply to neighbouring stations via distribution ties, a process which can take several hours to perform. It will then take months to a year before the failed station asset can be replaced and the MS returned to normal service due to equipment and design lead times and coordination. During this period, all customers supplied by the failed MS, and those fed from the neighbouring MSs, are exposed to significantly higher reliability risks due to a lack of second contingency supply. For similar reasons, maintenance or planned replacements cannot be completed at the neighbouring MSs during this period of limited capacity. As a result, system reliability can only be maintained when all MSs are maintained because the stations rely on each other to supply customers during contingencies, maintenance activities, and planned replacements.

Because customers are exposed to significantly reduced reliability when any MS is out-of-service, it is valuable to customers for Toronto Hydro to minimize the number and duration of station outages. For this reason, where possible, Toronto Hydro coordinates end-of-life asset replacements at a single MS during the same year, rather than having replacements and outages spread over multiple years.

1. MS Switchgear

The useful life of an MS Switchgear is 50 years. All of the MS switchgear targeted for replacement, listed in Table 11, will be between 61-70 years old at their time of replacement and are functionally obsolete. None of the targeted switchgear are arc-resistant and they are all equipped with oil circuit breakers. As seen in Figure 14 below, by not replacing switchgear containing oil circuit breakers, the condition of the breakers in the system will deteriorate and reach material deterioration and end of serviceable life. Operating these breakers in this condition increases failure and safety risks.

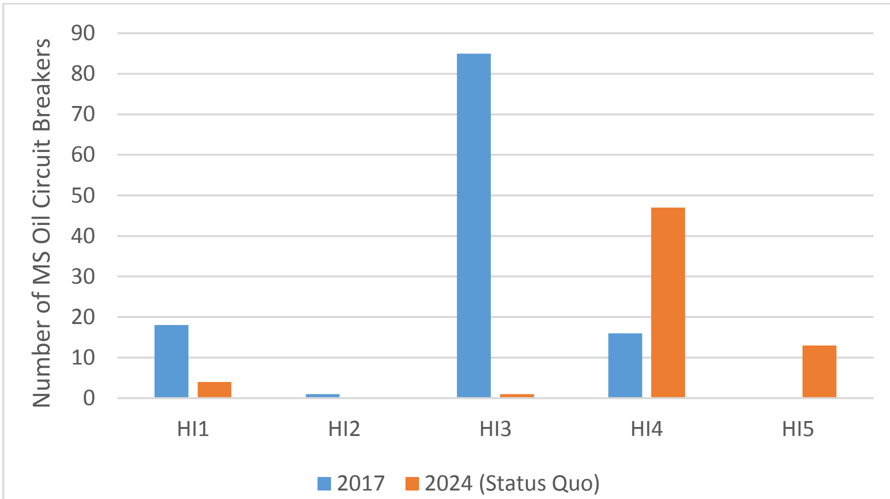


Figure 14: Condition of MS Oil Circuit Breakers as of 2017 and 2024 without investment

Toronto Hydro is prioritizing the replacement of its MS switchgear containing oil circuit breakers because the failure of these assets can cause fire and explosions similar to the KSO oil circuit breakers discussed in sub-section 2 of section E6.6.3.1 above. Such a failure mode presents a safety risk to station workers and the public, can cause collateral damage to other assets within the station or adjacent properties, and can have detrimental environmental impacts due to oil spill. Additionally, all MS oil circuit breakers are assumed to contain PCBs due to their age. Under this segment of work, all MS switchgear containing oil circuit breakers will be removed from service by the end of 2024. The switchgear planned for replacement over the 2020-2024 period, shown in Table 11 below, are currently showing signs of deterioration and are anticipated to have circuit breakers with at least material deterioration by 2024. Beyond condition, Toronto Hydro also considers age, presence (or lack) of SCADA, and failure impact to prioritize its MS switchgear replacements.

Table 11: MS Switchgear Proposed for Replacement

Station	Switchgear	Age at Replacement	Replacement Year
Pharmacy CPR MS	*T1SG*	61	2020
Rosethorne MS	*T1SG*	70	2020
Thistletown MS	*T1-T2SG*	65	2020
Browns Line MS	*T1-T2SG*	69	2021
Galloway Dearhamwoods MS	*T1SG*	62	2021
Neilson Drive MS	*T1-T2SG*	67	2021
Highbury MS	*T1-T2SG*	67	2022

Station	Switchgear	Age at Replacement	Replacement Year
Watercliffe MS	*T1SG*	66	2022
Bellamy Eglinton MS	*T1SG*	64	2023
Midland Lawrence MS	*T1SG*	62	2023
Brimley Seminole MS	*T1SG*	64	2024
Ravensbourne MS	*T1SG*	68	2024

The switchgear proposed for replacement are functionally obsolete, and replacement parts are no longer available. This makes maintenance of the existing switchgear difficult and expensive as replacement parts need to be custom-made or scavenged from other switchgear. Replacement with new switchgear supported by current manufacturers will allow Toronto Hydro to more readily maintain the switchgear as individual components fail in the future.

New switchgear will be arc-resistant and installed with vacuum circuit breakers, a low-maintenance and reliable model of circuit breakers that do not suffer from operating risks associated with oil circuit breakers. Each switchgear replacement will also involve the installation of a new SCADA system at the station since the existing system (if present) has far surpassed its useful life and is highly integrated with the switchgear. A SCADA system provides Toronto Hydro's control centre with the ability to monitor and control a station remotely to better manage the customer experience. Of the 12 stations targeted for a switchgear replacement, 5 of them currently have no SCADA system. These stations will receive a SCADA system for the first time as part of their switchgear replacement. As a result, MS switchgear renewal will also aid in Toronto Hydro's efforts to renew its fleet of RTUs and install new RTUs, as discussed in Section E6.6.3.3 below.

Figure 15 below shows the age profile of Toronto Hydro's MS switchgear in 2019 and 2024 under the proposed replacement and conversion plans (see the Area Conversions program),[5] which will remove switchgear from service. Toronto Hydro identified 12 MS switchgear which will require replacement over the 2020-2024 period due to their condition, age, use of oil circuit breakers, lack of SCADA, and failure impact. Following the replacement plan will result in only 2 units that exceed 65 years by 2024. Under the proposed replacement plan, the population of switchgear aged 61-75 years by 2024 will be kept similarto the population as in 2019. It is necessary to maintain this level as assets in this age group have the greatest risk of failure compared to other age groups.

[5] See E6.1 of this DSP.

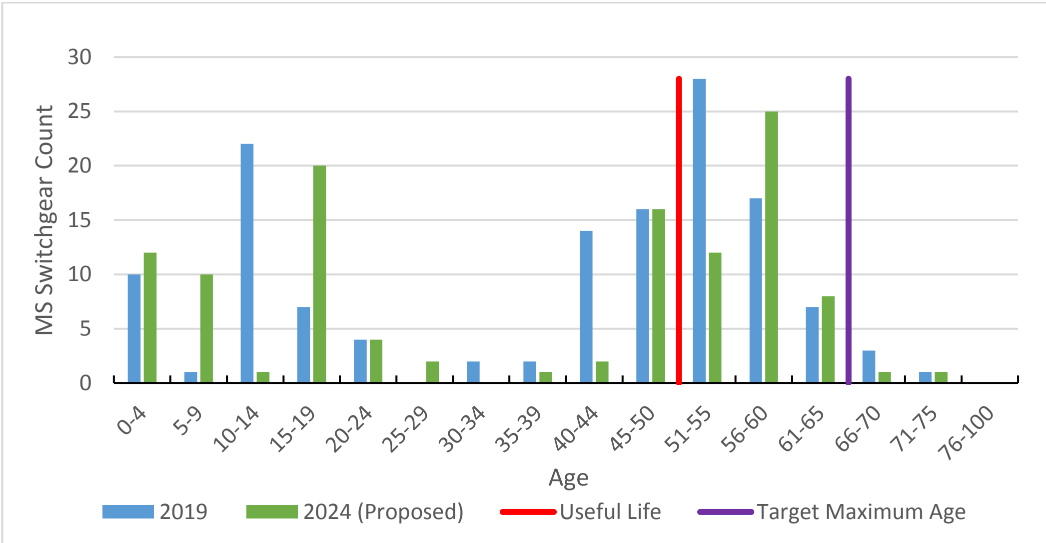


Figure 15: Age Profile of MS Switchgear

By replacing the end-of-life and obsolete MS switchgear targeted in this segment, Toronto Hydro will mitigate the risk of switchgear failure at its MSs, thereby maintaining system reliability.

2. Power Transformers

The useful life of a power transformer is 45 years. All transformers targeted for replacement in the 2020-2024 period, listed in Table 12, will be 60-67 years old at their time of replacement. The transformers will be replaced with units of the same or lesser capacity, where possible, to minimize costs. The proposed replacement is necessary because the reactive replacement of a failed unit takes three to six months to complete even with spare transformers on hand.

As shown in Figure 16 below, by not replacing power transformers by 2024 there is an increase in power transformers reaching conditions of material deterioration and end of serviceable life.

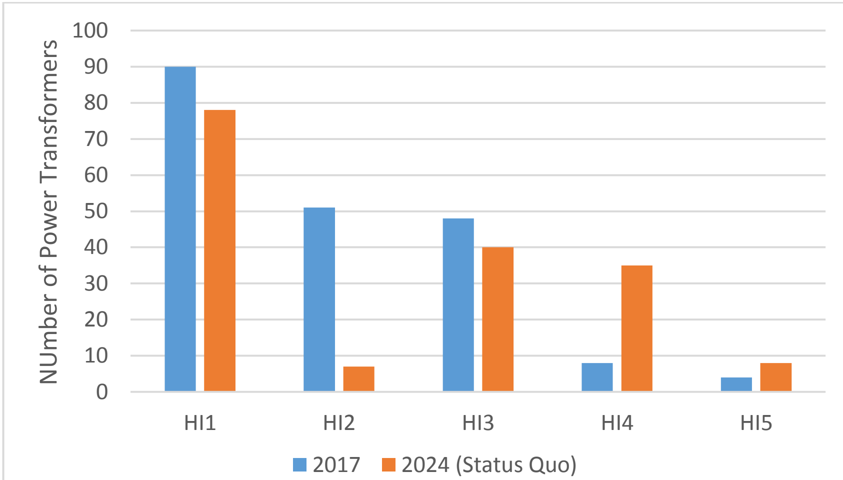


Figure 16: Power Transformer Asset Condition as of 2017 and in 2024 without investment

As shown in Table 12, in addition to condition, Toronto Hydro also considers age, loading, PCB concentration in oil,[6] and failure impact to prioritize its replacements.

Table 12: Power Transformers Proposed for Replacement

Station	ID	Additional Concerns	Age at Replacement	Replacement Year
Brimley Shaddock MS	*TR1*	- High power factor - SFRA[7] indications of winding deformation	65	2020
Pharmacy CPR MS	*TR1*	- High power factor - Low insulation resistance	61	2020
Belfield MS	*TR1*	- Low insulation resistance - SFRA indications of core defects and winding deformation	61	2021
Galloway Dearhamwoods MS	*TR1*	- High power factor - Low insulation resistance - DGA[8] indications of overheating	62	2021
Burlingame MS	*TR1*	- Elevated particle count in oil - Contains PCB - Higher than typical load	61	2022
Highbury MS	*TR1*	- High levels of moisture in oil	67	2022

[6] All power transformers are tested for PCBs with each of their oil tests, which occur annually.
[7] Sweep frequency response analysis ("SFRA") is a test often used to identify defects in the mechanical or electrical integrity of a power transformer.
[8] Dissolved gas analysis ("DGA") is a test often used to identify previous and/or persistent thermal and/or electrical faults occurring within a power transformer.

Station	ID	Additional Concerns	Age at Replacement	Replacement Year
		- Low oil dielectric breakdown		
Bellamy Eglinton MS	*TR1*	- Low oil dielectric breakdown - Elevated particle count in oil	64	2023
Brimley Bernadine MS	*TR1*	- High power factor - Low insulation resistance	64	2023
Humber Bay MS	*TR1*	- Contains PCB	66	2024
Windsor MS	*TR1*	- Higher than typical load	60	2024

Transformer replacements will include the replacement of the transformer's primary supply, discussed in the section below, as these assets exist within the station solely to supply or disconnect the power transformer. In doing so, this will allow Toronto Hydro to optimize their replacement strategy by minimizing station outages.

In addition to causing customer outages, power transformer failures can have significant safety and environmental impacts at a MS. Upon failure, the tank of the power transformer can rupture, result in oil fire, and even explode. This was the case for the 49-year old TR2 at DuPont MS which failed in 2003, as shown in Figure 17 below. Power transformers hold thousands of litres of oil which can fuel the fire that erupts.

Figure 17: Failed Power Transformer TR2 at DuPont MS in 2003

To this end, Toronto Hydro will also install an oil containment system as part of its power transformer replacements, if one is not already present at the station. Toronto Hydro has been following this practice for all of its power transformer replacements over the 2015-2019 period. The oil containment system will prevent the release of oil into the environment in case the power transformer develops an oil leak or its tank ruptures due to a failure.

Figure 18 below shows the age profile of Toronto Hydro's power transformers at the end of 2019 and 2024 under the proposed replacement and conversion plans (see the Area Conversions program),[9] which will remove power transformers from service. Toronto Hydro identified 10 power transformers which will be in need of replacement over the 2020-2024 period due to their condition, age, and failure impact. Under the proposed replacement plan, the transformer population aged 55-69 will be maintained at the current level as assets of this vintage have the greatest risk of failure.

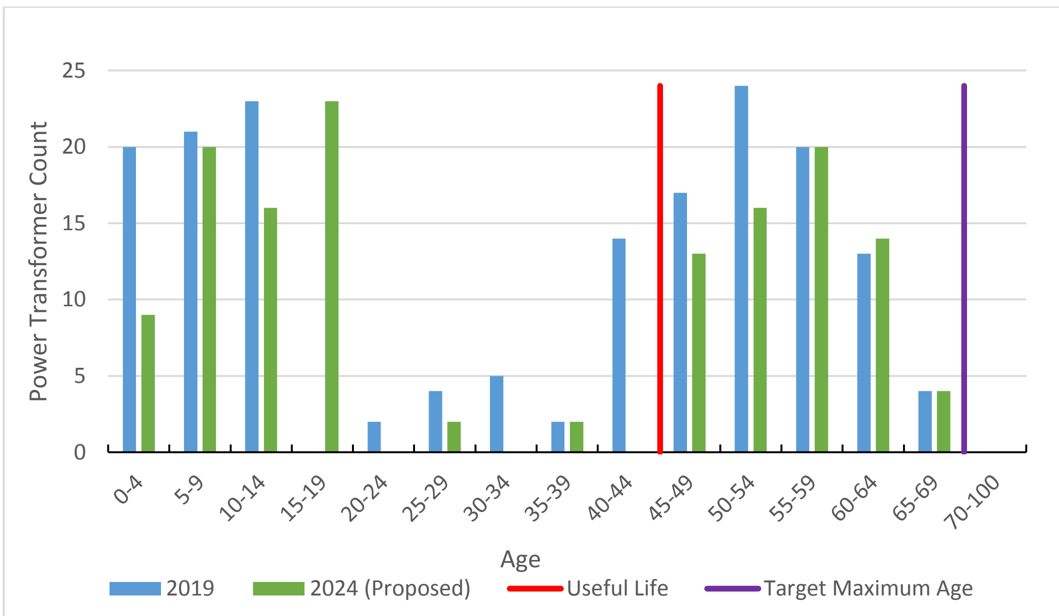


Figure 18: Age Profile of Power Transformers

By replacing the end-of-life power transformers targeted in this segment, Toronto Hydro will mitigate the risk of power transformer failure at its Municipal Stations, thereby maintaining the reliability of its MSs.

[9] See E6.1 of this DSP.

3. MS Primary Supply

The MS primary supply consists of all assets in the station between the distribution system and the primary side of the station transformer, including primary cable, primary disconnect switches, and primary circuit breakers. These assets are used to supply the station transformer with power, or to disconnect the transformer from its supply for maintenance or during a fault. It takes three months to reactively replace a failed primary supply. Prior to 2018, power transformer replacements were typically completed without replacing their MS primary supply. As part of this segment, Toronto Hydro proposes to replace the primary supply at MSs where power transformers were previously replaced.

The MS primary supply replacement projects will target MSs which meet the following criteria.

1) The MS had a transformer replacement from 2005 onwards,
2) The MS primary supply was not replaced,
3) The MS does not have a switchgear replacement planned for the 2020-2024 period (as replacement of the primary supply may be included with a switchgear replacement), and,
4) The MS is not planned to be decommissioned through voltage conversion activities (refer to the Area Conversions program).[10]

Over the 2020-2024 period, Toronto Hydro proposes to replace the primary supply at 11 MSs as listed in Table 13. These stations were selected on the basis of failure risk as determined through the age and configuration of the primary supply assets. Primary supplies will also continue to be replaced as part of power transformer replacements occurring at other stations in the 2020-2024 period (see previous section). This work will mitigate the risks of a primary supply failure.

Table 13: MS Primary Supplies Proposed for Replacement

Station	Age at Replacement	Replacement Year
Brimley Lawrence MS	65	2020
Thornton MS	65	2020
Wexford-Surrey MS	66	2020
Hardwick MS	63	2021
Porterfield MS	65	2021
Dalegrove MS	63	2022

[10] See E6.1 of this DSP.

Station	Age at Replacement	Replacement Year
Scarborough Golf Club Rd Ellesmere MS	64	2022
Lawrence Kennedy MS – TR1	69	2023
Renforth MS	61	2023
Centennial D'Arcy Magee MS	45	2024
Markham Pandora MS	60	2024

The useful life for a primary disconnect switch or a primary circuit breaker is 45 years. For non-lead primary cable, the useful life typically ranges from 25-50 years, depending on the type of cable; and for lead (PILC)[11] cable, the useful life is 75 years. All primary disconnect switches, primary circuit breakers, and non-lead primary cable will be past their useful life at the time of proposed replacement. In particular, all but one of the targeted primary supplies will have assets between 60-69 years old by that time.

Historically, Toronto Hydro has pursued a run-to-fail strategy for managing its MS primary supplies. However, since the failure of a primary supply results in a three month station outage, and many of the assets composing the primary supply are operating far beyond their useful life, a proactive replacement plan is required to manage failure risk.

The existing primary disconnect switches are obsolete end-of-life assets. They can no longer be replaced like-for-like as they are non-standard and no longer manufactured. Primary disconnect switches will be replaced with a standard padmounted switch commonly used in Toronto Hydro's distribution system. The existing MS primary breaker is also an obsolete end-of-life asset and will be replaced with a vacuum circuit breaker in a like-for-like configuration.

The existing non-lead primary cables targeted for replacement have surpassed their useful life, and existing lead cables will be approaching their useful life. These cables were installed either direct buried or in direct-buried ducts. These configurations generally hinder cable replacement if the cable were to fail, resulting in a replacement time of 3 months. On the other hand, if a primary cable fails in concrete-encased ducts, then the cable can be replaced within a few days. For this reason, end-of-life primary cable which is direct buried or in direct buried duct will be replaced with cable of the

[11] Paper Insulated Lead-Covered ("PILC") cable

same capacity within concrete-encased ducts. Existing lead (PILC) cable will be replaced with plastic (XLPE)[12] cable, thereby removing lead from Toronto Hydro's system.

By replacing the end-of-life and obsolete MS primary supplies, Toronto Hydro will mitigate the failure risk these assets pose at its MSs, thereby maintaining the associated reliability performance.

E6.6.3.3 Control and Monitoring

Toronto Hydro uses control and monitoring systems at its TSs and MSs to protect its equipment, provide operators with system oversight, and allow for remote switching operations. Ultimately this allows Toronto Hydro to reduce outage durations and provide customers with high reliability. Major Control and Monitoring assets include RTUs, protection relays, and interstation control wiring. A large portion of these assets are operating beyond their useful life and are at a heightened risk of failure. Toronto Hydro uses a risk-based approach to identify the highest priority assets for replacement and also to identify where installing new systems might be prudent, with the objective of cost-effectively maintaining levels of reliability. Toronto Hydro's most pressing risks and needs for its Control and Monitoring assets are summarized in Table 14 below.

Table 14: Control and Monitoring

Category	Description	Drivers and Failure Consequences
RTU Renewal	*Downtown DACSCAN RTU Replacements*	Main driver is failure risk of aging DACSCAN RTUs in Toronto's core. DACSCAN technology was first developed and installed 30 years ago and is now functionally obsolete. Its supplier is no longer in business and replacement parts are hard to find. The failure consequence is loss of telemetry data and remote control operation at the station (typically a TS) with the failed RTU.
	MOSCAD RTU Replacement	Main driver is failure risk of aging MOSCAD RTUs in Etobicoke area stations. MOSCAD technology was first developed and installed 25 years ago and is now functionally obsolete. Its supplier is no longer in business and replacement parts are hard to find. The failure consequence is loss of telemetry data and remote control operation at the station (typically a MS) with the failed RTU.

[12] Cross-Linked Polyethylene ("XLPE") cable

Category	Description	Drivers and Failure Consequences
	D20 M++/ME RTU Replacement	Main driver is failure risk of aging D20 M++/ME RTUs in Scarborough area stations. D20 technology is approximately 10-20 years old and parts for older units are no longer supported by its manufacturer and difficult to maintain. The failure consequence is loss of telemetry data and remote control operation at the station (typically a MS) with the failed RTU.
New RTU Installations	*New RTU Installations*	Main driver is improving reliability of MSs that currently do not have an RTU. Operators have little oversight of the status of equipment at these stations and rely on customers to alert them of outages. By installing RTUs at these stations, Toronto Hydro will have visibility of equipment status and remote control. This will reduce outage durations and operating costs (i.e. less labour hours for manual service restoration work at these stations).
Pilot-wire Protection and Interstation Control Wiring Renewal	*Pilot-wire Protection Renewal*	Main driver is to replace aging electromechanical pilot-wire protection systems used for large downtown customers (including financial institutions, hospitals, telecom companies, sewage plants, etc.). Failure consequence of these systems is an outage to large customers who rank reliability as their highest priority.
	Interstation Control Wiring Renewal	Main driver is the failure risk of aging copper control wires. Copper control wires allow information to flow between TSs and MSs and between TSs and customers with pilot-wire protection systems. Failure consequence is loss of pilot-wire protection, or loss of communication for critical communication infrastructure (i.e. SCADA, security systems, telephone lines, and other basic services).

Control and Monitoring assets are common to both TSs and MSs and vary in size and complexity depending on the station and its geographical location. Systems located in downtown Toronto TSs are treated with a higher priority than systems located in MSs. However, systems in all stations are important because control operators rely on them to oversee, control and protect the system.

1. RTU Renewal

As shown in Table 15 below, 37 percent of Toronto Hydro's RTUs will be operating at or beyond their 22 year useful life in 2019.[13] The majority of Toronto Hydro's RTUs are built from early computer technologies. Computer technology has advanced considerably in the past 20 years making it difficult to find replacement parts that maintain backwards compatibility with what are now obsolete and out-dated technologies (i.e. MOSCAD, DACSCAN, and D20 M++/ME). Table 15 below shows the types of RTUs in various geographical areas, and the percentage of RTUs that are in-service beyond their useful life (as of the end of 2019).

Table 15: RTU type, communication protocol, quantity, and percent past useful life in 2019

Geographical Area	RTU Type	Communication Protocol	Number of Assets	% of Assets Past Useful Life
Etobicoke	*Motorola SCADA (MOSCAD)*	DARCOM Radio	37	100%
	SEL Axion 2240	SD-9	27	0%
Scarborough	*D20 ME / D20M++*	Telephone Line (Bell Leased)	16	0%
	D20 MX	Telephone Line (Bell Leased)	1	0%
	SEL 2032	5 - Transit	13	0%
North York	*ACS7010A or NTU7010*	Telephone Line (Bell Leased)	17	0%
	SEL RTAC 3530	Telephone Line (Bell Leased)	6	0%
	SEL Axion 2240	Telephone Line (Bell Leased)	1	0%
Old Toronto	*DACSCAN MDO-11*	SONET/ Telephone Line (Bell Leased)	29	100%
	ABB microSCADA	SONET	1	0%
	D20 ME / D20M++	SONET	3	33%
	SEL 3332	SONET	26	0%
	SEL Axion 2240	SONET	5	0%
	GE DART	SONET	1	0%
Total			**183**	**37%**

[13] An RTU has a useful life of 22 years as identified in the Kinectrics Report K418021 "Useful Life of Assets", Aug. 28, 2009.

RTU replacement is driven by their failure risk and associated impact. Toronto Hydro considers RTUs to have a useful life of 22 years. Similar to other computer technologies, with increased age and operation, RTU circuit boards become increasingly prone to failure, and when they fail, do so without warning. All of Toronto Hydro's DACSCAN RTUs and MOSCAD RTUs were installed in the late 1980's and early 1990's and are operating beyond their useful life. Production of these obsolete RTUs has ceased and their manufacturers no longer exist in the market for support or supply of the parts required for repair. Where possible, field crews have salvaged parts from decommissioned units, but this method of maintaining units is becoming more difficult to sustain. Complicating matters, the majority of field staff with the knowledge and ability to troubleshoot these devices have retired. DACSCAN RTUs are located in critical downtown TSs serving thousands of customers, therefore their replacement is higher priority than other RTUs considered in this segment. MOSCAD RTUs are located in Etobicoke MSs and typically serve 4 kV MSs with less customers than other RTUs considered in this segment.

Most of Toronto Hydro's D20 M++/ME RTUs are younger than 22 years; however, some units have suffered several premature failures over recent years. Moreover, configuration software to modify or re-program these units requires use of legacy computer operating systems which are no longer supported by the original RTU manufacturer. Similarly to MOSCAD and DACSCAN RTUs, like-for-like replacement parts for legacy D20 RTUs are no longer available for purchase. To resolve these issues, Toronto Hydro proposes to replace these units with an incremental upgrade option. Two of Toronto Hydro's D20 RTUs are located at TSs while the remainder are located at downtown MSs or at 13.8 kV Scarborough MSs.

When an RTU fails, Toronto Hydro's control centre operators are disconnected from telemetry data and lose operational control of equipment at the station. This prevents operators from viewing the status of equipment at the station, leaving the system in a vulnerable state. If an RTU failure occurs at a critical station, field crews need to be dispatched to the station immediately to manually monitor equipment status and operate where required. This is necessary to ensure Toronto Hydro can adequately respond to outages and prevent equipment damage by ensuring the station operates within its limits. Combined with the difficulty of the repair work required, this makes a failure event operationally expensive and puts customers at risk of longer outages. Modern operation of the electrical grid relies upon having real-time data and control available at the station level at all times.

To mitigate RTU failure risk, Toronto Hydro plans to replace 14 DACSCAN RTUs, 15 MOSCAD RTUs, and 10 D20 RTUs over the 2020-2024 period. This represents all of Toronto Hydro's end-of-life

DACSCAN RTUs (located at downtown TSs), approximately half of Toronto Hydro's end-of-life MOSCAD RTUs (located at Etobicoke MSs), and all of Toronto Hydro's D20 RTUs (located at TSs, downtown MSs and Scarborough MSs). With the exception of MOSCAD RTUs, the remaining RTU units operating beyond their useful life expectancy are at stations with conversion and decommissioning plans and therefore do not require replacement. For MOSCAD RTUs, Toronto Hydro has limited its replacement volume to respect customer priorities as related to cost.

2. New RTU Installations

Toronto Hydro will have 11 MSs without remote monitoring and control in 2019 (i.e. 11 MSs without an RTU). Toronto Hydro plans to install new RTUs at six of these MSs during the 2020-2024 period as discrete projects. The remaining five MSs without an RTU will have RTUs installed as part of their MS Switchgear replacements during the 2020-2024 period, as detailed in sub-section 1 in Section E6.6.3.2. By the end of 2024, all 11 stations without a RTU will have one installed, thus enabling remote monitoring and control capabilities. The proposed MSs for RTU installation and the MSs which will receive RTUs via switchgear replacement are listed in Table 16 below. As a result of this investment, customers connected to these stations will receive the same high level of reliability as customers supplied by Toronto Hydro's other 116 SCADA-enabled MSs.

Table 16: New RTUs Proposed for Installation

Station	Segment	Installation Year
Pharmacy CPR MS	MS Switchgear (see Sub-Section 1 of E6.6.3.2)	2020
Midland-Danforth MS	New RTU Install	2020
Galloway Dearhamwoods MS	MS Switchgear (see Sub-Section 1 of E6.6.3.2)	2021
Ellesmere White Abbey MS	New RTU Install	2021
Panorama MS	New RTU Install	2022
Bellamy Eglinton MS	MS Switchgear (see Sub-Section 1 of E6.6.3.2)	2023
Midland Lawrence MS	MS Switchgear (see Sub-Section 1 of E6.6.3.2)	2023
Markham Eglinton MS	New RTU Install	2023
Brimley Seminole MS	MS Switchgear (see Sub-Section 1 of E6.6.3.2)	2024
Bellamy Lawrence MS	New RTU Install	2024
Livingston Guildwood MS	New RTU Install	2024

At stations without an RTU, Toronto Hydro control center operators have no visibility of equipment status. Consequently, they rely on customers to alert them of outages so they can dispatch field crews to perform the manual switching operations required to restore electrical service to affected customers. Manual switching takes longer to perform resulting in longer than necessary outages. As shown in Figure 19, stations equipped with SCADA tend to experience shorter outage durations compared to stations lacking SCADA. On average, the installation of SCADA is expected to reduce outage duration by approximately one hour.

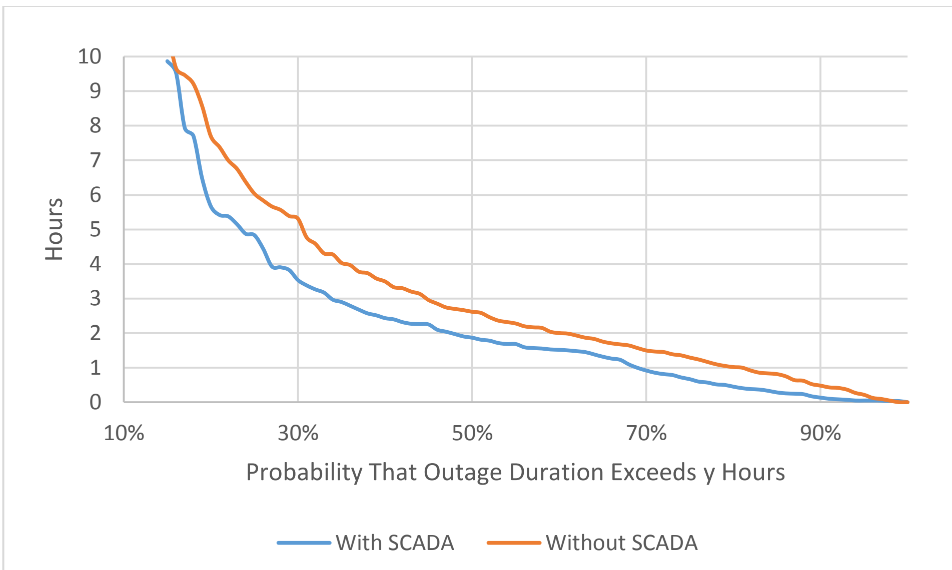


Figure 19: Reliability (SCADA Impact) at Stations with RTUs versus Stations without RTUs

Operating costs for stations without an RTU are higher because additional labour resources are required to investigate and perform the manual switching needed to restore service to customers. The information provided by RTU monitoring systems also allows Toronto Hydro engineers to collect important data such as station loading, number of faults, duration of outages, etc. which is used to perform proper planning and improve reliability in the future.

3. Pilot-wire Protection Renewal

The renewal of Toronto Hydro's pilot-wire protection systems is driven by high failure risk due to their age and their criticality in providing high reliability to certain large customers. High reliability is provided through the use of multiple source feeds (protected by a pilot-wire protection system). Pilot-wire protection renewal projects will only target pilot-wire systems used to protect the supplies of these individual customers, as opposed to Toronto Hydro's interstation pilot-wire protection systems.

Toronto Hydro's obsolete pilot-wire protection systems rely on electromechanical relays and copper control wiring running between TSs and customers. The majority of Toronto Hydro's pilot-wire protection systems operate using this obsolete technology. The electromechanical relays used are operating beyond their useful life of 30-years and are no longer available on the market. Further, planned switchgear replacements require circuit transfers with this protection system to new switchgear, since new switchgear cannot be made compatible with the obsolete pilot-wire protection relays an upgrade to newer line protection technology is required.

When a pilot-wire protection scheme fails, the individual customer supplied by the system and all of the customers supplied by the upstream switchgear are placed at an increased risk of outage. Without the pilot-wire protection to isolate a fault, the switchgear's bus differential protection would isolate the entire bus in the event of a fault. What should have been a single element failure, impacting only one customer, would become an entire TS switchgear outage affecting hundreds or thousands of customers, similar to the failure impact of TS switchgear as detailed in sub-section 1 of section E6.6.3.1above.

In addition to reducing failure risk, replacing Toronto Hydro's obsolete electromechanical and copper-based pilot-wire protection systems with digital relays and fiber communications has the following benefits:

- Improved protection of customer and utility equipment due to faster relay operation;
- New relays have self-diagnostics which simplifies troubleshooting and makes failures easier to predict;
- Less manual maintenance and testing since the new system has online monitoring and self-diagnostics; and
- As part of each project, copper lines are replaced with fiber. Toronto Hydro will have complete control of the fiber optic communication cables and not be reliant on a privately-owned third party corporation (many copper cables are owned by Bell); therefore, a faster response time can be provided by Toronto Hydro crews in the case of communication line failure.

To maintain a high-level of reliability for these critical customers and to facilitate switchgear replacements, Toronto Hydro proposes to upgrade the pilot-wire protections for 5 locations (with modern line differential protection) during the 2020-2024 period. This represents just under a quarter of Toronto Hydro's pilot-wire protection systems. Ideally, Toronto Hydro would replace all of these obsolete systems; however, cost consideration and resource requirements limit Toronto Hydro to upgrading the protections at one location a year.

4. Interstation Control Wiring Renewal

Renewal of Toronto Hydro's Interstation Control Wiring systems is driven by failure risk due to their age and criticality in supporting the connected SCADA and protection systems. For example, Interstation Control Wiring includes copper control cabling used for telecommunications, interstation pilot-wire protection systems, RTUs, station security, and other systems that rely on interstation communication. This control wiring is located in an outdoor environment, routing through Toronto Hydro's distribution system and interconnecting geographically diverse TSs and MSs as required. Failures due to deteriorated cable have become more frequent and difficult to repair.

Copper wire communication infrastructure is obsolete and no longer used by major communication companies. This has led many suppliers and manufacturers to cease support and manufacturing of replacement parts. Additionally, skilled labour familiar with the technology is hard to find or train. Given the critical nature of the information transmitted through the cables, failure can render entire systems non-functional. Table 17 below summarizes the impact that failure of copper control wiring can have depending on the system involved.

Table 17: Interstation Control Wiring – Failure Impact by System

System	Failure Impact
Interstation Pilot-Wire Protection	Potential loss of supply to a TS or MS switchgear, which would result in a power outage to all customers supplied by the switchgear
Station RTUs	Equivalent impact as loss of an RTU, as discussed in sub-section 1 of section E6.6.3.1
Station Security	Loss of access to MS/TS via swipe card, loss of security cameras, etc.

As an example of a recent failure, in May 2017, an Interstation Control Wiring cable between Gerrard TS and Sherbourne MS failed. To repair the failed control cable, Toronto Hydro had to replace 2.2 km of cabling at a total cost of $170 thousand dollars. The ensuing repair and replacement took approximately 5 months to perform. While the failure did not result in an outage for the entire 5-month period, the pilot-wire protection system between Gerrard TS and Sherbourne MS was out-of-service. Without the system to isolate a fault on the power cable between the two stations, all of the customers supplied by Gerrard TS and Sherbourne MS were exposed to an increased risk of outage as the upstream protections at Gerrard TS would have had to operate to isolate the entire Gerrard TS switchgear (rather than isolating the single power cable). As this case highlights, relying on reactive repair has tremendous risk due to the lengthy duration of increased exposure to higher impact outages.

To maintain the integrity of the systems supported by this control wiring, Toronto Hydro plans to replace 45 km of old copper cable with new fiber optics-based cables over the 2020-2024 period. This represents just under a quarter of Toronto Hydro's stations copper wiring network. Ideally, Toronto Hydro would replace all of its copper wiring; however, cost consideration, operational restrictions, and resource requirements limit Toronto Hydro to upgrading approximately 10 km a year.

E6.6.3.4 Battery and Ancillary Systems

As shown in Table 18 below, 23 percent of Toronto Hydro's Battery and Ancillary Systems will be operating beyond their useful life in 2019. Depending on the asset, replacement is required due to poor condition, old age, obsolescent technology, oil containing PCBs, or a mixture of these factors. The Battery and Ancillary Systems segment proposes replacing these supporting systems as required to maintain station integrity and system reliability for Toronto Hydro customers.

Table 18: Battery and Ancillary Systems Demographics

Asset Type	Total # of Assets	Useful Life	Assets Beyond Useful Life (2019)	Assets Beyond Useful Life with Program (2024)
Battery and Charger Systems	165	10-12 years	22%	16%
Station Service Transformers	34	45 years	26%	12%
Air Compressors	10	15 years	20%	0%
Total	**209**	**-**	**23%**	**15%**

In addition to the renewal of the assets included above, Toronto Hydro has identified 3 TSs with flood risk requiring mitigation, as detailed in sub-section 3 of section E6.6.3.4.

1. Battery and Charger Renewal

A battery and charger system is installed at every TS and MS to provide DC power supply and backup for essential protection, control and SCADA systems. Due to their critical functionality, station batteries and chargers must be maintained in reliable condition, as required by the Transmission System Code (as specified in Section 10.7.1 thereof). These systems must be able to supply power for a minimum of 8 hours after the loss of main AC power. As shown in Table 19 below, 22 percent of Toronto Hydro's battery and charger systems will be operating beyond their useful life in 2019.

Table 19: Battery and Charger Systems Demographics

Asset Type	Assets Beyond Useful Life Current State (2019)	Assets Beyond Useful Life Without Program (2024)
Battery and Charger Systems	22%	64%

Battery and charger system renewal is required to mitigate their failure risk. Station batteries have a useful life between 10-12 years (depending on the battery type). Batteries deteriorate to the point of failure as they age and a significant number of them are past or close to the end of their useful life. Without any action during the 2020-2024 period, the proportion of batteries operating beyond their useful life would be 64 percent by 2024. Without replacement, failures will increase resulting in higher risk of reduced reliability for Toronto Hydro customers as well as significant equipment damage. As shown in Figure 20 below, the proposed replacement of 67 units will ensure the maximum age of the batteries in the system is kept at 14 years.

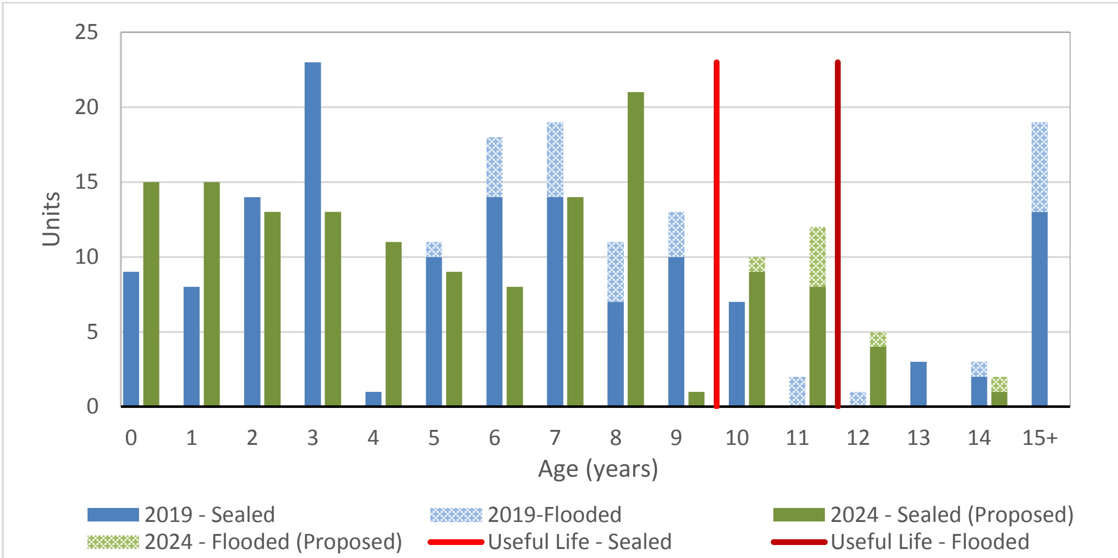


Figure 20: Age Profile of Station Batteries

When a battery or charger fails, its MS or TS loses the source of DC power supply. This in turn renders all protection, control, Station RTUs, and other communication systems non-functional. Failure of protection and control systems is a major safety and reliability risk as the station would lose its ability to isolate faults. Otherwise, loss of functionality would affect the Control and Monitoring systems with similar failure impacts to those detailed in Section E6.6.3.3. Due to this significant failure impact, Toronto Hydro installs a second, back-up battery and charger system at its critical TSs. As listed in Table 20 below, Toronto Hydro proposes the replacement of 67 station batteries and charger systems over the 2020-2024 period. When replacing batteries and chargers, Toronto Hydro will also replace any end-of-life or obsolete DC panels and other smaller series components with similar failure impact.

Table 20: Battery & Charger Proposed Replacement Plan

Year of Replacement	Downtown Replacements	North York Replacements	Scarborough Replacements	Etobicoke Replacements	Total
2020	1	3	4	3	**11**
2021	1	0	5	7	**13**
2022	1	0	5	7	**13**
2023	2	1	2	10	**15**
2024	2	3	6	4	**15**
Total	**7**	**7**	**22**	**31**	**67**

The proposed Battery & Charger Systems replacement projects will maintain the reliability of service for a vast geographical area (as shown in Figure 21 below).

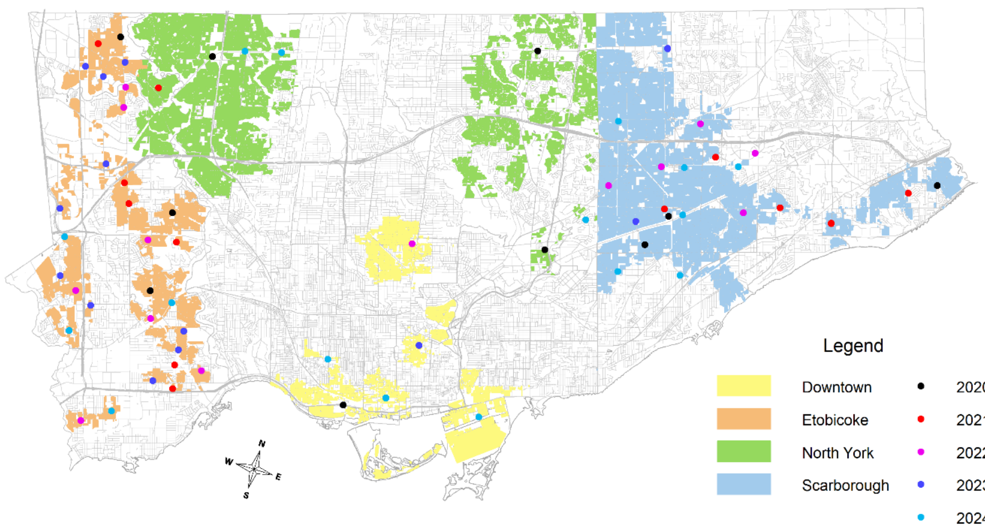


Figure 21: Geographical locations of the 2020-2024 proposed Battery & Charger Systems

2. Station Service Transformer Renewal

A station service transformer ("SST") supplies a station with AC power for use in the station's heating, lighting, and DC charging systems. Therefore, an SST failure has a similar impact as a battery or charger failure, discussed in Sub-Section 1 of Section E6.6.3.4 above. The DC system can maintain the function of critical protection, control, station RTUs, and other communication systems for 8 hours without AC power. However, following this period of time, AC power must be restored or the batteries will drain and these systems will be rendered non-functional. Due to this significant failure impact, Toronto Hydro installs two SSTs at its downtown TSs. SST replacement projects will only target SSTs supplying these TSs.

Historically, Toronto Hydro has pursued a reactive strategy for managing its SSTs. However, following the failure of an SST at Cecil TS in 2015, Toronto Hydro re-examined this approach for its downtown TSs. For such stations, each SSTs must be custom ordered with a total lead time for replacement exceeding seven months. This is a considerable period of exposure to a second contingency event, which would cause the station batteries to deplete after 8 hours.

Such a lengthy lead time combined with the number of SSTs operating at an advanced age necessitate a proactive replacement plan for SSTs located at downtown TSs. A proactive replacement strategy is in line with customer priorities, because customers supplied from Toronto Hydro's downtown TSs tend to prioritize reliability over cost, and the cost to replace SSTs is relatively small compared given the criticality of their functions.

Toronto Hydro owns 34 SSTs which supply its downtown TSs. As shown in Table 21 below, 26 percent of these SSTs will have reached or surpassed their useful life in 2019. In addition, 9 percent of these SSTs contain PCBs and present risk of environmental damage if they leak.

Table 21: Stations Service Transformer Demographics

Asset Type	Assets Beyond Useful Life Current State (2019)	Assets Beyond Useful Life Without Program (2024)	Assets with PCB >2ppm
Stations Service Transformers	26%	29%	9%

SST renewal is required to mitigate failure risks associated with their age. As shown in

Figure 22, nine of the targeted SSTs will exceed their useful life by 2019. Without action during the 2020-2024 period, 29 percent of these SSTs will be operating beyond their useful life by 2024.

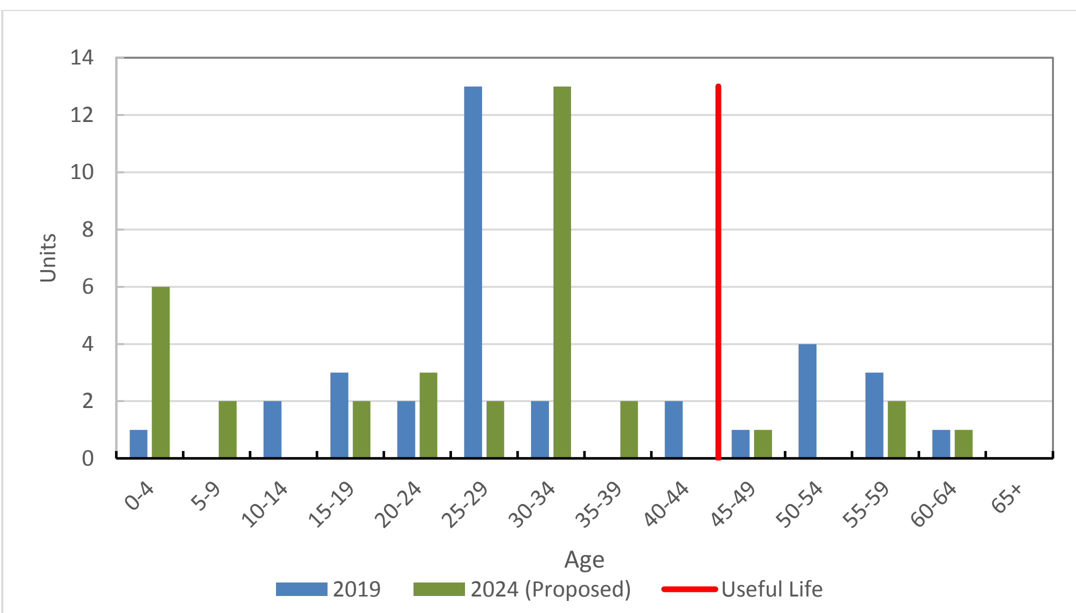


Figure 22: Age Profile of Station Service Transformers

The nine SSTs past useful life by 2019 are located at six TSs (each TS has two SSTs). As listed in Table 22 below, Toronto Hydro plans to replace one SST at each of these six TSs during the 2020-2024 period. This will significantly mitigate the risk of coincident SST failures at these TSs, and in turn will mitigate customer outage risk.

Table 22: SST Proposed Replacements

Station	Asset	Replacement Year
Main TS	*SSTC*	2022
Dufferin TS	*SST2*	2022
Windsor TS	*SST2*	2023
Duplex TS	*SST1*	2023
Cecil TS	*SST1*	2024
Carlaw TS	*SST1*	2024

In addition to the loss of critical systems identified above, a failure of an oil-containing SST risks leaking oil containing PCBs (when present) or causing a fire or an explosion. Most SSTs are located in close proximity to other critical station assets and pose risk of collateral damage. Therefore, SST replacements will mitigate this safety and environmental risk, and remove PCBs from Toronto Hydro's stations.

3. Other Ancillary Renewal

Several other ancillary systems require replacement or installation to maintain the integrity of Toronto Hydro's station infrastructure. Toronto Hydro's most pressing risks and needs for these ancillary assets are summarized in Table 23 below.

Table 24 lists the other ancillary assets to be installed or replaced over the 2020-2024 period.

Table 23: Other Ancillary Systems - Drivers

Asset Group	Asset Class	Drivers and Failure Consequences
Other Ancillary Systems	*Air Compressors*	The main driver is failure risk due to age. 20 percent of Toronto Hydro's remaining[14] air compressors will reach or surpass their useful life by the end of 2021. Air-blast circuit breakers require compressed air to operate and isolate fault currents. When an air compressor fails and an air-blast circuit breaker is unable to clear a fault, the fault triggers the upstream protection systems to operate extending the outage to thousands more customers and damaging equipment.
	Flood Mitigation System	The main driver for this segment is failure risk of station assets due to flooding. The stations selected for sump pump installation have major equipment installed in the basement (e.g. switchgear,station services etc.) that is at risk in case of water infiltration. Lack of sump pumps can lead to a water build-up which could eventually short-circuit and damage equipment.

Table 24: Proposed Other Ancillary Systems Projects

Station	Asset	Replacement Year
Glengrove TS	*Sump Pump*	2020
Carlaw TS	*Sump Pump*	2020
Wiltshire TS	*Sump Pump*	2020
Bridgman TS	*Air Compressor*	2021
Ossington MS	*Air Compressor*	2021

The majority of air compressor units will be decommissioned by 2024 either due to voltage conversion (see Area Conversions program[15]) or switchgear replacements. However, ten units will remain, and two units, at Bridgman TS and Ossington MS will have exceeded their useful life. Given their significant failure impact (loss of breaker operation) and their relatively small cost of renewal, Toronto Hydro plans to replace these two units during the 2020-2024 period. As shown in Figure 23 below, air compressor systems have been failing in recent years, and many repairs have been required. The average age of these air compressors at the time of failure was 13 years, and the units proposed for replacement will be 15 years old upon replacement.

[14] As switchgear containing air-blast circuit breakers are decommissioned or replaced, air compressors may no longer be required within a station.
[15] See E6.1 of this DSP.

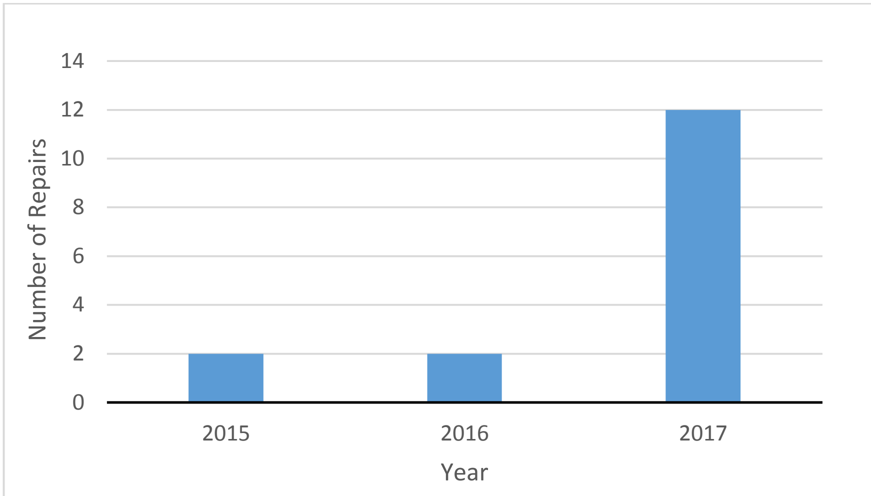


Figure 23: Air Compressor Repairs from 2015 to 2017

Toronto Hydro has also identified three TSs with flooding risks which can be addressed via installation of sump pumps. These stations contain significant assets in their basements and have shown signs of water ingress in the past. Therefore, Toronto Hydro plans to install three sump pumps during the 2020-2024 period. The stations planned for sump pump installation are Carlaw TS, Glengrove TS, and Wiltshire TS.

E6.6.4 Expenditure Plan

Table 25 provides the Historical (2015-2017), Bridge (2018-2019) and Forecast (2020-2024) expenditures for the Stations Renewal program. The Program has been organized in 2020-2024 based on the type of system addressed, work required, and driver of the work.

Table 25: Historical & Forecast Program Costs ($ Millions)

Segment	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Transformer Stations[16]	7.6	6.3	7.0	5.7	15.4	15.5	21.1	16.4	14.2	7.4
Municipal Stations[17]	3.2	3.0	7.6	8.3	3.7	8.2	8.6	7.0	6.6	7.3
Control and Monitoring[18]	0.3	1.3	2.9	2.8	3.6	2.9	4.3	4.4	4.5	6.0
Battery and Ancillary Systems[19]	0.1	0.8	1.4	2.8	1.1	0.9	1.2	1.6	1.7	1.7
Total	**11.3**	**11.6**	**19.0**	**19.7**	**23.7**	**27.5**	**35.3**	**29.4**	**27.0**	**22.4**

Spending in the Stations Renewal program over the 2015-2019 period is projected to be $85.3 million. This spending is forecast to be less than filed due to changes in Toronto Hydro's execution plan. Toronto Hydro evaluated its early (i.e. 2015 and 2016) program performance and modified its forecast and future plans based on that evaluation. In particular, coordination issues with interdependent TS Switchgear replacement projects had a significant impact on Toronto Hydro's 2015-2019 execution plan and spending. Several high-spend projects were dependent on the completion of Copeland TS, which had its energization date delayed to late 2018 (as discussed in the Stations Expansion program).[20] In general, small delays on high spend projects resulted in reductions in overall spending.

Due to the challenges and delays experienced over the 2015-2019 period, there is a back-log of high-priority station projects that need to be completed urgently. As discussed in Section E6.6.3, station assets are critical and have lengthy replacement times. Keeping station asset demographics in check is the best strategy to prevent their high failure impact and, in turn, maintain system reliability. For the 2020-2024 period, Toronto Hydro proposes to spend $141.5 million. A large portion of this spending is required to address deferred, urgent projects. Completion of key projects such as

[16] Transformer Stations segment includes the TS portion of the former Switchgear Renewal program, the former Circuit Breaker Renewal program, and the new TS Outdoor Switch sub segment.
[17] Municipal Stations segment includes the MS portion of the former Switchgear Renewal program, the former Power Transformer Renewal program, and the new MS Primary sub segment.
[18] Control and Monitoring segment includes the former Stations Control and Monitoring program and the new Pilot-wire Protection and Interstation Control Wiring renewal sub segments.
[19] Battery and Ancillary Systems segment includes the former Stations DC Battery Renewal program and the former Stations Ancillary Systems program.
[20] See E7.4 of this DSP.

Copeland TS and improved work processes established during its 2015-2019 program execution will enable Toronto Hydro to complete this volume of work as proposed.

Work in the Stations Renewal program is prioritized at three different levels. First, TS work is prioritized above MS work, since TSs supply customers of all classes and serve more customers than MSs. Therefore, the TS segment as a whole and the portions of the Control and Monitoring and Battery and Ancillary Systems relevant to TSs are given the highest priority. Secondly, the work inside each segment is prioritized differently depending on the specific failure outcomes and risks associated with each asset class. Thirdly, in respect of each asset class, work is prioritized using a variety of data and considerations including condition, customers served, load served, maintenance effort, obsolescence, and asset age.

E6.6.4.1 TS Segment Expenditure Plan

As shown in Table 26 below, Toronto Hydro forecasts to spend $42.1 million over the 2015-2019 period in its TS segment. This is less than Toronto Hydro proposed to spend in its 2015-2019 CIR filing, of the $42.1 million, expenditures for TS switchgear renewal and TS outdoor breaker renewal are expected to be $30.2 million and $11.8 million, respectively. Underspending for TS switchgear replacement is due to the delayed energization of Copeland TS (which must occur before the switchgear at Windsor TS is replaced) and other reasons as discussed in the section below. TS outdoor breaker replacement spending is forecast to be higher than planned due to an increase in unit replacement costs caused by additional scope driven by Hydro One requirements.

Table 26: TS Historical & Forecast Segment Costs ($ Millions)

Expenditures	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
TS Switchgear	5.3	3.8	3.9	4.2	12.9	14.9	20.3	15.1	12.8	5.5
TS Outdoor Breakers	2.3	2.5	3.1	1.5	2.5	0.4	0.4	0.9	0.9	1.4
TS Outdoor Switch	NEW SUBSEGMENT					0.1	0.4	0.4	0.5	0.5
Total	**7.6**	**6.3**	**7.0**	**5.7**	**15.4**	**15.5**	**21.1**	**16.4**	**14.2**	**7.4**

For the 2020-2024 period, Toronto Hydro proposes to spend $74.5 million in its TS segment. As with the 2015-2019 CIR filing, the majority of the 2020-2024 spending is planned for TS switchgear renewal. The remainder is for the replacement of TS outdoor breakers and TS outdoor switches.

Located in different stations than TS outdoor breakers and switches, TS switchgear units have longer replacement and lead times and more complex design and construction, and require more capital investment. For these reasons, TS switchgear are prioritized above the other assets in the TS segment, and in the Stations Renewal program overall.

1. TS Switchgear

As shown in Table 27 below, Toronto Hydro forecasts $30.2 million in spending on TS switchgear over the 2015-2019 period. This spending was or will be incurred for seven switchgear units over the 2015-2019 period, three of which will be completed during 2015-2019 and the other four units will see the majority of their costs carried into the 2020-2024 period.

Table 27: TS Switchgear - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Units (Switchgear)	-	-	1	1	1	-	-	1	3	1

The three switchgear units that will be completed over the 2015-2019 period are found at Carlaw TS (2017), Wiltshire TS (2018), and Strachan TS (2019). Significant spending had already been incurred for these units prior to 2015, and then continued into the 2015-2019 CIR period (forecast to be $15.3 million during 2015-2019, as shown in Table 28 below). Meanwhile, $14.4 million in spending is forecast for 2015-2019 in relation to the start of the replacements at Windsor TS (A5-6WR), Strachan TS (A5-6T), Duplex TS (A1-2DX), and Carlaw TS (A4-5E). Additional to the 2015-2019 CIR filing, $0.5 million in spending is forecast for the replacement of breakers at Dufferin TS, which was identified as being urgent due to their poor condition.

Table 28: 2015-2019 TS Switchgear Replacements – Historical and Bridge Expenditures ($ Millions)

Switchgear Unit	Actual			Bridge		Planned Completion
	2015	2016	2017	2018	2019	
Carlaw TS (A6-7E)	0.3	0.7	1.8	-	-	2017
Wiltshire TS (A3-4W)	1.3	1.5	1.1	1.7	-	2018
Strachan TS (A7-8T)	3.5	1.5	0.9	0.5	0.5	2019
Windsor TS (A5-6WR) ***Strachan TS (A5-6T)*** ***Duplex TS (A1-2DX)*** ***Carlaw TS (A4-5E)***	0.2	0.1	0.1	1.5	12.4	2020-2024
Dufferin TS Breaker Replacements	-	-	-	0.5	-	2018
Total	**5.3**	**3.8**	**3.9**	**4.2**	**12.9**	

The volume of TS switchgear replacements proposed in Toronto Hydro's 2015-2019 CIR filing was subsequently adjusted as a result of several factors. Notably, two of the planned replacements at Windsor TS depended on the completion of Copeland TS. A delay in the Copeland TS energization had a cascading effect, pushing the first unit to be replaced at Windsor TS (A5-6WR) into the 2020-2024 period and the second unit (A3-4WR), which must be completed after the first, into the following period.

Another factor was the Pan American Games hosted by the City of Toronto in 2015. In 2015, work on TS switchgear replacements was slowed to (i) enable labour resources to be redirected to assist in preparations for the event; and (ii) ensure the system was not in a contingency state. Another factor was Hydro One's replacement of a transformer at Gerrard TS in 2016. As that work conflicted with Toronto Hydro's proposed replacements at Carlaw TS, resources were directed away from Carlaw TS until the Hydro One transformer replacement was completed.

The above discussed factors resulted in a back-log of TS switchgear still requiring replacement. As detailed in sub-section 1 of Section E6.6.3.1, a significant number of TS switchgear units are operating beyond their useful life. The longer the demographic remains at an elevated age, the greater the probability of eventual failure. Due to their criticality, even the failure of one of these units cannot be tolerated. Therefore, Toronto Hydro's strategy is to renew the critical TS switchgear units identified in this Program.

Informed by lessons learned from the 2015-2019 period, Toronto Hydro has further mitigated risks to attaining its 2020-2024 replacement plan, proposing only five TS switchgear replacements over the 2020-2024 period. As shown in Table 29 below, a total of $53.8 million is proposed for 2020-2024 to complete the four carry-over units (further to spending incurred in 2015-2019) and $14.8 million for one additional unit at Bridgman TS (A1-2H). By completing this plan, Toronto Hydro will maintain the number of TS switchgear operating beyond their useful life around the current level, which is approximately 27 percent.

Table 29: 2020-2024 TS Switchgear Replacements – Forecast Expenditures ($ Millions)

Switchgear Unit	Forecast					Unit Estimate	Planned Completion
	2020	2021	2022	2023	2024		
Windsor TS (A5-6WR)	2.0	1.0	2.4	8.8	4.2	20.5	2024
Bridgman TS (A1-2H)	-	4.4	6.0	3.0	1.3	14.8	2024
Strachan TS (A5-6T)	4.0	6.3	3.5	0.5	-	16.7	2023
Duplex TS (A1-2DX)	3.7	4.4	1.6	0.5	-	15.0	2023
Carlaw TS (A4-5E)	5.2	4.2	1.6	-	-	16.1	2022
Total	**14.9**	**20.3**	**15.1**	**12.8**	**5.5**		

This work plan is attainable (and necessary to manage the aging and deteriorating TS switchgear population) in light of the change in circumstances and lessons learned to date during the 2015-2019 period. For example, with the completion of Copeland TS, work on Windsor TS replacements – Toronto Hydro's highest priority switchgear replacements – can begin. Other projects, largely being carry-overs, have known execution risks and challenges that have been addressed over the 2015-2019 period. Toronto Hydro completed replacement of the Carlaw TS (A6-7E) switchgear in 2017. This switchgear replacement will serve as a template for the successful completion of projects into the 2020-2024 period.

The cost of replacement is forecast to be $20.5 million for Windsor TS (A5-6WR), $14.8 million for Bridgman TS (A1-2H), $16.7 million for Strachan TS (A5-6T), $15.0 million for Duplex TS (A1-2DX) and $16.1 million for Carlaw TS (A4-5E). These estimated costs are generally in line with actuals observed for the Carlaw TS project carried out to date over the 2015-2019 period and take into account the size and complexity of the replacements proposed. For example, spending on the Windsor TS (A5-6WR) replacement is higher due to extra scope required to transfer feeders to Copeland TS, which is needed to enable the decommissioning and replacement of the A5-6WR switchgear.

The proposed spending varies between years given, among other things, the need for major component purchases (e.g. switchgear lineup purchases in 2020, 2021 and 2022) during high-spend years. This follows the typical cost profile of a TS switchgear replacement project, where, as the project progresses, actual spend declines after the completion of major procurements but the work becomes more labour intensive. Similarly, the higher spend between 2019 and 2023 compared to the 2015-2018 period is due to the planned purchase of significant switchgear materials and the significant capital contribution expected to be made to Hydro One. Major component purchases and most Hydro One capital contributions for the three units to be completed between 2015 and 2019 were made prior to 2015.

Toronto Hydro plans to replace the TS switchgear units at Main TS, Wiltshire TS, and Windsor TS (which cannot be addressed during the 2020-2024 years) in the following (2025-2029) period. With the exception of the Windsor TS switchgear (A3-4WR), the units have been assessed to entail lower failure and operational risks compared to others prioritized over the 2020-2024 period. After reviewing all factors (age, condition, customers, load, breaker type, arc-flash rating, enclosure construction), these units were found to be lower priority than those proposed. The A3-4WR exception is still high priority but is dependent upon the completion of the A5-6WR for space and capacity reasons and simply can't be done in the period.

Toronto Hydro believes accepting the increased risk – i.e. continuing to operate these units beyond their useful life – to be prudent and necessary in the context of its overall TS Switchgear replacement needs, priorities, and ability. With continued maintenance and monitoring, Toronto Hydro will mitigate failure risk until the units can be replaced.

Toronto Hydro prioritizes the replacement of its TS switchgear in order of the failure risk presented by each switchgear. The failure risk is assessed qualitatively by considering the following factors.

Table 30: TS Switchgear Prioritization

Factor	Prioritization
Age	Older switchgear are given higher priority
Enclosure Construction	Brick constructed switchgear is given higher priority
Condition Assessment	Switchgear receiving worse condition assessments (including breaker condition assessments) are given higher priority

Factor	Prioritization
Type of circuit breaker	Priority given in order of: 1) Obsolete oil circuit breaker 2) Obsolete non-oil air blast circuit breaker 3) Obsolete asbestos-based air magnetic circuit breaker 4) Current SF_6 circuit breakers 5) Current vacuum circuit breakers
Load	Switchgear supplying larger quantities of load are given higher priority
Protection and Control	Switchgear with obsolete protection and control systems are given higher priority.
Arc Flash Rating	Switchgear with lower arc flash protection ratings are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority

2. TS Outdoor Breaker

As shown in Table 31 below, Toronto Hydro forecasts the replacement of 28 TS outdoor breakers over the 2015-2019 period at a cost of $11.8 million.

Table 31: TS Outdoor Breakers - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Units (Breakers)	4	2	5	11	6	1	1	2	2	3

For the 2020-2024 period, Toronto Hydro is proposing $4.0 million in spending – a 50 percent reduction compared to the 2015-2019 period, during which the majority of Toronto Hydro's end-of-life oil-based TS outdoor breakers will have been replaced. For the 2020-2024 period, Toronto Hydro only proposes to replace 9 units. This will limit the proportion of TS outdoor breakers operating beyond their useful life at around the current rate of 4 percent. All of the breakers proposed for replacement contain oil and are operating beyond their useful life, and need to be replaced as detailed in Sub-Section 2 of Section E6.6.3.1.

The average cost for TS outdoor breaker replacement over the 2015-2019 period is roughly $0.4 million per unit. This is slightly higher than initial unit pricing estimated for the 2015-2019 period which was $0.3 million per unit. The increase in unit cost was caused by the additional scope required to meet recent Hydro One standards. For new breaker replacements, Hydro One requires a demarcation panel to act as a clean interface point between Toronto Hydro's and Hydro One's equipment, which would minimize confusion between the ownership of Hydro One and Toronto Hydro assets. However, with these new requirements, Toronto Hydro was required to pay a capital contribution to Hydro One. Toronto Hydro has adjusted its 2020-2024 estimates accordingly, forecasting $0.4 million per unit replacement.

Given its 2015-2017 historical achievements in this segment, Toronto Hydro is well positioned to successfully execute its replacement plan for 2020-2024, which proposes at most three replacements in a single year.

Toronto Hydro prioritizes the replacement of its TS outdoor breakers based on the failure risk presented by each breaker. The failure risk is assessed qualitatively by considering the following factors.

Table 32: TS Outdoor Breakers Prioritization

Factor	Prioritization
Age	Older breakers are given higher priority
Type of circuit breaker	Priority given in order of: 1) Oil circuit Breaker 2) SF_6 Breaker 3) Vacuum Breaker
Condition Assessment	Circuit breakers receiving worse condition assessments are given higher priority
Load	Breakers supplying larger quantities of load are given higher priority
PCBs	Breakers containing higher levels of PCBs are given higher priority
Protection and Control	Breakers with obsolete protection and control systems are given higher priority.
Any other issues raised by station crews (such as broken components)	Given higher priority

3. TS Outdoor Switches

As shown in Table 33 below, Toronto Hydro proposes to replace 61 TS outdoor switches during the 2020-2024 period at a cost of $1.9 million. This is a new spending category to address the need identified in Sub-section 3 of Section E6.6.3.13 and has no historical costs associated with it. By replacing these 61 units during the 2020-2024 period, Toronto Hydro will reduce the number of TS outdoor switches operating beyond their useful life to 16 percent. As detailed in Sub-section 3 of Section E6.6.3.1, if this work is not undertaken during the 2020-2024 period, almost three quarters of Toronto Hydro's TS outdoor switches will be operating beyond or within 5 years of their 50-year useful life. Performing the proposed work will allow Toronto Hydro to sustainably manage the demographics of its switches over the longer term and reduce the number of switch failures.

Table 33: TS Outdoor Switch Renewal – Forecasted Unit Volumes

	Forecast				
	2020	2021	2022	2023	2024
Units (Switches)	3	12	12	18	16

The year-by-year pacing for TS outdoor switch replacement has been developed to target the highest priority switches, while maximizing efficiencies in terms of construction and outage coordination. As this is new work, only three switches have been proposed for replacement in 2020. This will serve as a pilot project and allow Toronto Hydro to make any refinements necessary to achieve the greater volumes proposed in later years. For the years 2020-2022, Toronto Hydro proposes replacements in sets of three switches per year because each selected set can be replaced in a single outage. This reduces unit costs and reliability risk to customers (which would be higher if each switch was replaced as a separate project). For the years 2023 and 2024, Toronto Hydro has grouped bus disconnect switches with common outages into its replacement plans, which would similarly lead to efficiencies in terms of unit cost and outage coordination.

Toronto Hydro prioritizes the replacement of its TS outdoor switches based on the failure risk presented by each switch. The failure risk is assessed qualitatively by considering the following factors.

Table 34: TS Outdoor Switches Prioritization

Factor	Prioritization
Age	Older switches are given higher priority
Switch Type	Priority given in order of: 1) Feeder tie switches 2) Bus disconnect switches 3) Line disconnect switches
Number of repairs	Switches with more repairs are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority

E6.6.4.2 Municipal Stations (MS) Expenditure Plan

As shown in Table 35 below, Toronto Hydro expects to spend $25.9 million over the 2015-2019 period in its MS segment. This includes anticipated spending of $14.6 million and $11.3 million for MS switchgear renewal and power transformer renewal, respectively.

Table 35: MS Historical & Forecast Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
MS Switchgear[21]	2.4	1.7	4.6	4.1	1.9	5.3	5.8	4.3	3.7	4.3
Power Transformer	0.9	1.4	3.1	4.2	1.7	1.9	2.1	2.0	2.1	2.2
MS Primary Supply	NEW SUBSEGMENT					1.0	0.7	0.7	0.7	0.8
Total	**3.2**	**3.0**	**7.6**	**8.3**	**3.7**	**8.2**	**8.6**	**7.0**	**6.6**	**7.3**

During the 2020-2024 period, Toronto Hydro proposes to spend $37.7 million in its MS segment. This spending includes allowances for the addition of a new MS primary supply sub segment, an increased scope of work for power transformer replacements, and the inclusion of the distribution portion of work for MS switchgear replacements in this segment's budget (rather than in the Overhead or Underground System Renewal programs[22] to achieve work bundling). The majority of the 2020-2024 spend relates to MS switchgear renewal ($23.3 million). The remaining spending is planned for replacement of power transformers and MS primary supplies.

[21] Please note the 2015-2019 expenditures do not necessarily align with the volume of units completed since project costs were spread across 2-3 years.
[22] Exhibit 2B, Schedules E6.5, E6.2, and E6.3.

MS switchgear and power transformers are the main assets for a MS. They have the longest replacement and lead times, the largest design and construction work requirements, and the highest cost (including design, material, and construction) compared to assets covered under the MS primary supplies, or other assets located at MSs included in the Control and Monitoring, and Batteries and Ancillary Systems segments. For these reasons, MS switchgear and power transformers are prioritized before all other MS assets, including those covered in the Control and Monitoring and Batteries and Ancillary Systems segments.

MS switchgear and power transformers replacement candidates are prioritized against each other depending on their associated failure risk, which is evaluated qualitatively and described in the subsections below. The replacement of MS primary supplies is prioritized according to age.

1. MS Switchgear

Over the 2015-2019 period, Toronto Hydro replaced 11 switchgear at 11 MSs. Table 36 below provides an annual breakdown of the units completed, and proposed, between 2015 and 2024.

Table 36: MS Switchgear - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Units (Switchgear)	2	0	4	4	1	3	3	2	2	2
Total Feeders[23]	8	0	10	16	3	10	10	7	6	7

The cost to replace a switchgear varies depending on the number of feeders supplied by the switchgear (a measure of size) and the complexity of the distribution portion of the project. A switchgear replacement typically requires all feeder trunks to be replaced in concrete encased ducts. The distribution portion of work that is required is determined by whether concrete encased ducts already exist in the system and the length of feeder and/or duct bank required to be installed.

Historical actuals from 2014 to 2017 were used to arrive at a unit cost of approximately $0.6 million per feeder, which includes both the station and distribution scopes of work. This unit cost was used to forecast expenditures for the 2020-2024 period. Historical unit costs are less than forecasted unit costs for two reasons. First, the two switchgear completed in 2015 were carry-over projects from the

[23] This is the total number of feeders supplied by the switchgear whose replacements were, or are forecasted to be, completed in the specified year.

2012-2014 period, and hence their total cost is not captured in Table 36 above. Second, the majority of the switchgear replacements over the 2015-2019 period did not include the expense of the distribution portion of work, the cost of which was instead included in the Underground and Overhead System Renewal programs.[24] Once these two factors are accounted for, the historical unit cost aligns with the forecast unit cost of $0.6 million per feeder. A balance between annual cost, system need, and ability to execute resulted in an average pace of 2-3 units per year.

Toronto Hydro prioritizes the replacement of its MS switchgear based on the failure risk presented by each switchgear. The failure risk is assessed qualitatively by considering the following factors.

Table 37: MS Switchgear Prioritization

Factor	Prioritization
Age	Older switchgear are given higher priority
Condition Assessment	Switchgear receiving worse condition assessments (including breaker condition assessments) are given higher priority
Type of circuit breaker	Priority given in order of: 1) Obsolete oil circuit breaker 2) Obsolete non-oil air blast circuit breaker 3) Obsolete asbestos-based air magnetic circuit breaker 4) Current SF_6 circuit breakers 5) Current vacuum circuit breakers
Load	Switchgear supplying larger quantities of load are given higher priority
SCADA (Supervisory Control and Data Acquisition) system present?	MSs without SCADA are given higher priority
Resiliency of the surrounding distribution system to withstand switchgear failures	MSs in areas of low resiliency are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets to be replaced

Age, condition assessment, circuit breaker type, and issues raised by station crews are used to gauge the probability of a switchgear failure and when a switchgear has reached end-of-life. Furthermore,

[24] Exhibit 2B, Schedule E6.2, E6.3 and E6.5.

switchgear loading, existence of SCADA, and resiliency of the surrounding distribution system (i.e. ability to withstand switchgear failures) are used to gauge the impact of the switchgear failure and the priority of the replacement.

2. Power Transformer

Over the 2015-2019 period, Toronto Hydro expects to complete the replacement of 15 power transformers at 14 MSs. As part of these replacements, Toronto Hydro also replaced the MS primary supply at 6 of the 14 MSs. Table 38 below provides an annual breakdown of the units completed and forecast over the 2015-2024 period.

Table 38: Power Transformer - Historical Actual, Bridge, and Forecast Unit Volumes[25]

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Power Transformers	2	0	5	6	2	2	2	2	2	2

Historical actuals from 2014 to 2017 were used to arrive at a unit project cost of approximately $1.0 million per transformer, which was used to forecast expenditures. The scope of work at each station includes the replacement of the power transformer, installation of an oil containment system, and replacement of the MS primary supply.

Historical unit costs are less than forecasted unit costs for two reasons. First, the two transformers completed in 2015 were carry over projects from the 2012-2014 period. Hence the total expense of these two projects is not captured in the 2015-2019 period. Second, the majority of the transformer replacements over the 2015-2019 period did not also involve the replacement of the associated MS primary supply. Once these two factors are accounted for, the historical unit cost aligns with the forecast unit cost of $1.0 million.

A balance between annual cost, system need, and ability to execute resulted in an average pace of 2 units per year. Toronto Hydro prioritizes the replacement of its power transformers based on the failure risk presented by each transformer. The failure risk is assessed qualitatively by considering the following factors.

[25] Please note the 2015-2019 expenditures do not necessarily align with the volume of units completed since project costs were spread across 2-3 years.

Table 39: Power Transformer Prioritization

Factor	Prioritization
Age	Older transformers are given higher priority
Dissolved gas-in-oil analysis	Transformers in worse condition are given higher priority
Condition Assessment	Transformers receiving worse condition assessments are given higher priority
Loading	Transformers loaded higher relative to their capacity are given higher priority
Load	Transformers supplying larger quantities of load are given higher priority
PCB concentration in oil	Transformers with a higher PCB concentration are given higher priority
Resiliency of the surrounding distribution system to withstand transformer failures	MSs in areas of low resiliency are given higher priority
Any other electrical tests (such as power factor and insulation resistance tests)	Given higher priority
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets to be replaced

Age, dissolved gas-in-oil analysis, loading, and other electrical tests are used to gauge the probability of a power transformer failure and when an asset has reached end-of-life. Further, transformer loading, PCB concentration in the transformer oil, and resiliency of the surrounding distribution system (i.e. ability to withstand power transformer failures) are used to gauge the impact of the power transformer failure and the priority of the replacement.

3. MS Primary Supply

Over the 2015-2019 period, Toronto Hydro did not plan or complete any project which solely replaced a MS's primary supply. As a result, there are no historical actuals for these projects. Over the 2020-2024 period, Toronto Hydro proposes to replace 11 MS primary supplies. The forecasted unit volumes are shown in Table 40 below.

Table 40: MS Primary Supply - Forecasted Units

	Forecast				
	2020	2021	2022	2023	2024
Primary Disconnect Switch[26]	3	2	2	2	1
Primary Breaker[26]	0	0	0	0	1

The spending forecast was developed using a unit cost of $0.37 million. A balance between annual cost, system need, and ability to execute resulted in an average pace of 2 units per year. The scope of work required for an MS primary supply replacement is dominated by the distribution portion involving the replacement of the primary cable and related civil work. Therefore, unit costs were developed based on: the costs of similar distribution projects completed in the past, and the material cost of the new asset to be installed (padmounted switch or circuit breaker).

E6.6.4.3 Control and Monitoring Expenditure Plan

As shown in Table 41 below, Toronto Hydro expects to spend $11.0 million over the 2015-2019 period in its Control and Monitoring segment. For the 2020-2024 period, Toronto Hydro proposes to spend $22.1 million in its Control and Monitoring segment.

Table 41: Control and Monitoring Historical & Forecast Segment Costs ($ Millions)

Expenditures	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
RTU Renewal	0.3	0.8	1.8	1.6	1.6	1.3	2.7	2.7	2.8	3.6
New RTU Installation	-	-	1.0	0.2	0.4	0.4	0.4	0.4	0.4	0.8
Pilot-wire Protection Renewal	-	0.5	0.1	1.0	1.6	0.6	0.6	0.6	0.6	1.0
Interstation Control Wiring Renewal	NEW SUBSEGMENT					0.6	0.6	0.6	0.6	0.6
Total	**0.3**	**1.3**	**2.9**	**2.8**	**3.6**	**2.9**	**4.3**	**4.4**	**4.5**	**6.0**

For the 2020-2024 period, the majority of proposed spending is for RTU renewal, which is largely allocated to replace end-of-life DACSCAN RTUs at downtown TSs. The remaining proposed spending is planned for new RTU installations, pilot-wire protection upgrades and a new sub segment,

[26]*The primary cable associated with these assets will also be included in the replacement projects and has been included in the unit costs.*

Interstation Control Wiring Renewal. This new sub segment was added to renew end-of-life copper cables which have not previously been considered under any other programs. Proposed replacements are otherwise a continuation of Toronto Hydro's 2015-2019 CIR plan with cost forecasts updated to accurately reflect the proposed work.

The Control and Monitoring segment is mainly prioritized according to the failure risks and outage impacts on customers. Stations with larger number of customers and at higher risk of asset failure will be given higher priority compared to stations with lower number of customers and lower failure risks. Priority of replacements is assessed qualitatively by evaluating various factors as shown below:

Table 42: Control and Monitoring Prioritization

Factor	Prioritization
Age	The older the RTU or asset, the higher the priority is assigned.
Number of Customers	The larger number of customers connected to the station, the higher the priority.
Load	The larger amount of load (MVA), the higher the priority.
Failure rate	RTUs/assets at stations with higher incident of failures/repairs will have higher priority.
Voltage conversion planned (see Section E6.6.5.3)	Stations with voltage conversion being planned do not need any of their assets to be replaced

1. RTU Renewal

Table 43: RTU Replacement - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
DACSCAN RTUs	-	-	-	2	2	1	3	3	3	4
MOSCAD RTUs	1	5	7	6	5	3	3	3	3	3
D20 M++/ RTUs	-	-	-	1	-	1	2	2	2	3

a. <u>DACSCAN and MOSCAD RTU Replacement</u>

As shown in Table 43, Toronto Hydro forecasts to replace four DACSCAN and 24 MOSCAD RTUs over the 2015-2019 period. Spending is forecast to be $2.0 million for DACSCAN units and $4.0 million for MOSCAD units.

Actual RTU replacements cost more than estimated Toronto Hydro's 2015-2019 filing. This was because additional time was required for investigative and design work, beyond that which was expected. Considerable time was spent researching and specifying a replacement RTU to ensure it would be backwards compatible with existing Toronto Hydro systems (while considering emerging technological trends).

Future forecasts and estimates have been refined based on lessons learned from actual project implementation. For the 2020-2024 period, Toronto Hydro proposes $8.8 million in spending to replace 14 DACSCAN RTUs at a unit cost of approximately $0.6 million, and $3.1 million to replace 15 MOSCAD RTUs at a unit cost of approximately $0.2 million.

- **DACSCAN RTUs**: This spending and work volume is a significant increase from Toronto Hydro's 2015-2019 replacement proposal as these RTUs are critical due to their age and importance in maintaining reliability in the downtown area. The 14 units represent all of Toronto Hydro's end of life DACSCAN RTUs. Any remaining DACSCAN RTUs will be replaced via TS switchgear replacement projects or rendered obsolete as their corresponding MSs are converted. Achieving the proposed pacing will require good planning and proper coordination, but is attainable now that Toronto Hydro has developed a replacement solution to use as a template.
- **MOSCAD RTUs:** As detailed in 1, all of Toronto Hydro's 37 MOSCAD RTUs in-service will be past their end-of-life by 2019. Ideally, Toronto Hydro would replace all of these units. However, given financial constraints and the higher priority replacement of DACSCAN RTUs, Toronto Hydro proposes a reduced volume of work for MOSCAD replacements compared to its 2015-2019 plans. This work volume represents approximately half of Toronto Hydro's end-of-life MOSCAD RTUs and allows Toronto Hydro to manage its overall RTU demographics so that only 12 percent are operating beyond their end-of-life by 2024, a substantial improvement from 37 percent at the end of 2019.

b. <u>D20 M++/ME RTU Replacement</u>

As shown in Table 43, Toronto Hydro forecasts to replace one legacy D20 M++ RTU over the 2015-2019 period at a forecast spend of $0.1 million. An increased number of D20 D20 M++ /ME failures have occurred and its manufacturer has recently ended support for the model most commonly used in Toronto Hydro's system (the D20 ME). Therefore, Toronto Hydro proposes to upgrade these units to the new platform to enable continued support and parts availability.

The D20 M++ replacement project planned for 2018 was added as a pilot project to familiarize Toronto Hydro's design and field staff with the new D20 MX platform, which has considerable software changes from Toronto Hydro's existing systems. Based on the expertise and experience gained in this regard, corrective repair and upgrade of failed legacy units based on the new platform can be feasibly carried out.

For the 2020-2024 period, Toronto Hydro proposes $1.2 million to replace ten legacy D20 M++/ME RTUs. Besides the pilot D20 M++/ME RTU replacement forecasted for 2018 completion, replacement of these assets is new to the Stations Renewal program. Unlike other RTUs replaced in this segment, the D20 platform manufacturer provides upgrade support from their obsolete platform. Therefore, Toronto Hydro proposes to replace its D20 M++/ME units with a comparable replacement from the original manufacturer. This manufacturer support saves Toronto Hydro work effort (e.g. resources for rewiring) and allows the utility to cost effectively renew its D20 platform, as evidenced by the lower RTU replacement costs compared to MOSCAD or DACSCAN RTUs.

Ten D20 M++/ME RTU replacements are proposed to renew all of Toronto Hydro's D20 RTUs at stations with no voltage conversion plans. The remaining legacy D20 RTUs are proposed to operate until customers supplied are converted to higher voltage distribution systems and the relevant stations decommissioned.

2. New RTU Installation

As shown in Table 44, Toronto Hydro forecasts to install five new RTUs over the 2015-2019 period. Spending during the period is forecast to be $1.6 million. Similar to other work completed in the Control and Monitoring segment, RTU installation cost were underestimated in Toronto Hydro's 2015-2019 CIR filing. At that time, Toronto Hydro had a small sample of historical projects to base cost estimates on and several aspects of the scope of work required refinement. Future forecasts and estimates have been refined based on lessons learned from actual completed projects.

Table 44: New RTU Installation - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
New RTUs	-	-	2	1	2	1	1	1	1	2

For the 2020-2024 period, Toronto Hydro proposes $2.3 million in spending to install six new RTUs. As detailed in 2, in combination with RTU installations integrated into MS switchgear replacement projects, this volume enables SCADA at all remaining Toronto Hydro stations without voltage conversion and decommissioning plans.

3. Pilot-wire Protection Renewal

As shown in Table 45, Toronto Hydro forecasts to upgrade the pilot-wire protection system for nine locations over the 2015-2019 period (in alignment with the proposed 2015-2019 plan). Spending during the period is forecast to be $3.3 million.

Table 45: Pilot-wire-Protection Renewal - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Locations[27]	-	-	1	1	7	1	1	1	1	1

For the 2020-2024 period, Toronto Hydro is proposing $3.5 million to upgrade protection systems for five locations. This is a slight reduction in planned upgrades compared to the 2015-2019 period. Most of the upgrades (scheduled for completion in 2019) are required to enable load transfer from the Windsor TS (A5-6WR) switchgear to the new switchgear at Copeland TS (to facilitate the Windsor TS switchgear replacement discussed in Sub-Section 1 of Section E6.6.4.1 and to utilize Copeland TS). The quantity of work to be completed in 2019 is significantly higher compared to the proposed for other years. In a normal year, Toronto Hydro is more than capable of upgrading one pilot-wire location per year. As the switchgear installed at Copeland TS was designed with pilot-wire protection in mind, a portion of the upgrade work has already been completed. Also due to the overall criticality of Copeland TS projects in Toronto Hydro's system plan, more resources than usual will be assigned to complete the work.

Toronto Hydro's proposed pacing is attainable and informed by 2015-2019 progress in replacing these assets. For example, in 2016/2017, Toronto Hydro upgraded protections for a large customer in the financial district at a cost of $0.6 million. Toronto Hydro expects pilot-wire upgrades proposed between 2020 and 2023 to have similar cost per location due to their similar natures. The cost for

[27] Toronto Hydro's 2015-2019 CIR filing reported units in terms of pilot-wire relays. The actual scope of work extends beyond relay replacement (e.g. communication channel/fiber upgrade). Due to the scope that is required independent of the number of relays, unit attainment is better measured on a per location basis and historical figures have been adjusted accordingly.

the location proposed for 2024 is expected to be higher than average due to the higher number of feeders and the longer route of fiber required between Toronto Hydro's TS and the customer.

4. Interstation Control Wiring Renewal

Toronto Hydro has not previously performed planned replacement of its interstation control wiring. However, a number of recent failures exposed Toronto Hydro's downtown customers to reduced reliability. Advancements in communication infrastructure have also made finding compatible parts and skilled labour difficult, in turn making reactive repair risky and costly. Therefore, as shown in Table 46 below, Toronto Hydro proposes to invest $3.1 million to replace approximately 45-kilometres of interstation control wiring with new fiber optic cables during the 2020-2024 period.

Table 46: Interstation Control Wiring Renewal - Forecasted Unit Volumes

	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**
Control Wiring Length (kilometres)	9	9	9	9	9

Toronto Hydro has identified 19 critical control wire sections interconnecting downtown TSs, MSs, and large customers. These sections make up the backbone of Toronto Hydro's control wiring network in the Esplanade TS, Strachan TS, and Windsor TS service areas. These stations supply Toronto's downtown core, the region in the city with the highest reliability demands. For this reason, these sections have been prioritized for replacement over the remainder of Toronto Hydro's aging control wiring.

The total length of wiring proposed for replacement is approximately 45 km. To replace these wires, Toronto Hydro proposes to replace 3-4 interstation control wire sections per year, resulting in approximately 9 km of cable replaced each year. This pace will allow Toronto Hydro to target its highest priority stations at an attainable replacement rate.

As discussed in Sub-Section 4 of Section E6.6.3.3, control wires of this type have failed in the past. Emergency replacement of these wires cost approximately $0.08 million per kilometre of cable, including urgent material order and procurement which drive up the cost beyond that of planned work. Taking this into account, Toronto Hydro estimates the cost of a planned replacement at $0.07 million per kilometre of cable, adding up to approximately $0.6 million to replace 9 kilometres of cable per year over the 2020-2024 period.

E6.6.4.4 Battery and Ancillary System Expenditure Plan

As shown in Table 47 below, Toronto Hydro forecasts to spend $6.3 million during the 2015-2019 period in its Battery and Ancillary System segment. This spend is expected to be of $3.6 million, $0.8 million, and $1.8 million respectively for batteries and chargers, SSTs, and ancillary projects.

Table 47: Battery and Ancillary Systems Historical & Forecast Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Battery and Charger Renewal	0.1	0.8	1.4	0.7	0.6	0.7	0.9	1.0	1.1	1.1
SST Renewal	-	-	0.1	0.4	0.3	-	-	0.6	0.6	0.6
Other Ancillary Renewal	-	-	-	1.7	0.1	0.2	0.3	-	-	-
Total	**0.1**	**0.8**	**1.4**	**2.8**	**1.1**	**0.9**	**1.2**	**1.6**	**1.7**	**1.7**

During the 2020-2024 period, Toronto Hydro proposes to spend $7.3 million in its Battery and Ancillary System segment. Similar to the 2015-2019 period, the majority of 2020-2024 spending is for Battery and Charger Renewal, with the remainder allocated to SST Renewal and Other Ancillary Renewal.

The battery and ancillary systems at Toronto Hydro TSs are prioritized above the same assets at MSs due to the sheer volume of customers that are served through each TS. A TS asset failure affects many more customers than the same asset failing at an MS. Battery and ancillary systems projects at downtown MSs are prioritized over the projects at Horseshoe MSs, because the volume of customers served by Horseshoe MSs is much lower. Also, survey results have shown that Horseshoe customers have indicated preference of lower electricity rates over reliability of service.

1. Battery and Charger Renewal

As shown in Table 48 below, Toronto Hydro replaced 44 battery and charger systems during the 2015-2019 period.

Table 48: Battery and Charger Renewal - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Battery and Charger Systems	3	9	13	9	10	11	13	13	15	15

A battery and charger system's replacement cost can vary considerably (between $0.04 million and $0.15 million), depending on its size, type, and station served. Additionally, project cost can vary depending on the scope of work required to correct deficiencies related to a station's broader DC or AC wiring system.

During the 2015-2019 period, Toronto Hydro replaced a considerable number of larger battery and charger systems at its downtown TSs, resulting in a higher unit cost than what is typical. TS battery and charger replacement projects are more costly than their MS counterparts due to their increased size and complexity. One such replacement took place at Terauley TS (located next to City Hall), where Toronto Hydro replaced and relocated a battery and charger system and the station's DC panels at a total cost of $0.5 million. The scope of work completed for this project was greater than typical battery and charger system replacements. Additional scope was required to relocate the battery and charger system so that its space could be used for a TS switchgear replacement planned for the 2025-2029 period. As the batteries were at end-of-life, adding relocation to the scope of work prevents the need for duplicate investment in the 2025-2029 period. Excluding the replacement at Terauley TS, Toronto Hydro forecasts replacement of 43 battery and charger systems at an average cost of $0.07 million per replacement.

For the 2020-2024 period, Toronto Hydro is proposing $4.8 million in spending to replace 67 end-of-life battery and charger systems. This spending and pacing is a continuation of Toronto Hydro's 2015-2019 replacement strategy. Toronto Hydro proposes to maintain the number of its battery and charger systems operating beyond their useful life at existing levels in order to maintain system reliability. This volume is attainable based on historical performance and reasonable given these assets' criticality to the operation of Toronto Hydro's TS and MS protection and control systems. Toronto Hydro forecasts total spending to be $4.8 million, or $0.07 million per replacement which is in line with 2015-2019 actuals.

Toronto Hydro prioritizes the replacement of its battery and charger systems based on the failure risk and impact posed by each system. The failure risk is assessed qualitatively by considering the following factors.

Table 49: Battery and Charger Prioritization

Factor	Prioritization
Age	Older battery and charger systems are given higher priority.
Number of Customers	The larger the number of customers connected to the station, the higher the priority (e.g. battery and charger systems located at Transformer Stations are given higher priority than those located at Municipal Stations).
Failure Rate	DC systems that have frequent SCADA alarms and have a history of individual cell failure/repairs will be given a higher priority.
Other factors determined on a case-by-case basis	Systems which are non-standard or contain obsolescent technology are given higher priority (e.g. some DC distribution panels are obsolete). Spare parts that should be accessible routinely are no longer available (e.g. DC panel breaker).
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets replaced.

2. Station Service Transformers (SST)

As shown in Table 50 below, Toronto Hydro replaced three SSTs during the 2015-2019 period. Spending during the period is forecast to be $0.8 million.

Table 50: SST Renewal - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
SSTs	-	-	1	1[28]	1[28]	-	-	2	2	2

[28] Replacement of SSTs was not included in Toronto Hydro's 2015-2019 CIR filing. Units were proactively replaced in 2017 and 2018 after they were identified as having significant failure risk.

For the 2020-2024 period, Toronto Hydro is proposing $1.9 million to replace 6 SSTs located at 6 of its 15 downtown TSs. This volume is proposed to address the need detailed in Sub-Section 2 of Section E6.6.3.4.

Work to be completed in 2018 and 2019 was added following Toronto Hydro's 2015-2019 CIR filing. This work was driven by failure risk due to each SST's age, condition, and failure impact. A typical SST project can vary between $0.27 million and $0.33 million depending on the scope of the project – e.g. replacement and relocation (higher cost) or replacement in place (lower cost). Exact scope depends on site specific constraints (e.g. space, flood risk).

Toronto Hydro will be able to achieve the replacement of 6 SSTs during the 2020-2024 period by replacing 2 SSTs per year beginning in 2022. SST replacements have not been planned earlier than 2022 due to their relative priority compared to other projects in the segment and in an effort to maintain a flat investment profile over the 5 year period. The proposed spending of approximately $0.3 million per unit is consistent with Toronto Hydro's latest estimates to replace an SST.

3. Other Ancillary Renewal

As shown in Table 51 below, Toronto Hydro replaced four air compressors, installed one sump pump and installed two fire barrier or suppression systems during the 2015-2019 period. Spending during this period is forecast to be $1.8 million. While spending is in line with planned, actual project completion differs from what was planned:

- **Air compressors**: Toronto Hydro planned to replace six air compressors. By the end of 2019, Toronto Hydro forecasts to replace four of these units at a total cost of $0.4 million. Toronto Hydro cancelled two air compressor replacements due to a change in voltage conversion plans for the MS where they were located.
- **Flood mitigation system:** Toronto Hydro did not plan to install any sump pumps. However, the utility has increasingly focused on storm hardening its system to ensure reliable power supply for its customers. After completing station risk assessments, Toronto Hydro directed $0.1 million for the installation of one sump pump in 2019.
- **Fire Barrier/Suppression Systems**: Toronto Hydro planned to install one fire suppression system and two fire barrier systems during the 2015-2019 period. The utility installed one fire suppression system installation and one fire barrier at a total cost of $1.3 million. The remaining fire barrier installation was cancelled due to a change in conversion plans for the

MS it was intended for. The fire suppression system installed in 2018 cost more than expected with a final spend of $0.9 million compared to its estimate of $0.3 million due to a significant increase in scope discovered during the detailed design phase. However, given the criticality of the assets protected (2 x 230 kV – 27.6 kV transformers at Toronto Hydro's Cavanagh TS) and site specific constraints, an alternative to this increased cost was not available.

Table 51: Other Ancillary Renewal - Historical Actual, Bridge and Forecast Units

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Air Compressor Replacements	-	-	-	4	-	-	2	-	-	-
Sump Pump Installations	-	-	-	-	1[29]	3	-	-	-	-
Fire Barrier/ Suppression System Installations	-	-	-	2	-	NO UNITS PLANNED				

For the 2020-2024 period, Toronto Hydro is proposing $0.5 million to install three sump pumps at TSs identified during risk assessments, and replace two end-of-life air compressors located at Bridgman TS and Ossington MS.

Toronto Hydro prioritizes the replacement of its ancillary systems based on the failure risk and impact posed by each system. The failure risk is assessed qualitatively by considering the following factors.

Table 52: Ancillary System Prioritization

Factor	Prioritization
Failure Impact on a system-by-system basis	Systems that have more far reaching impacts are given higher priority. For example, basement flood would have a more immediate impact on the system compared to failure of an air compressor. On the other hand, air compressor failure could render entire switchgears breakers inoperable, which could cascade into a larger system problem, therefore replacing air

[29] Replacement of this sump pump was not included in Toronto Hydro's 2015-2019 CIR filing. It was installed following the outcome of a station risk assessment.

Factor	Prioritization
	compressor systems will be given a higher priority compared to SSTs.
Age	Older systems are given higher priority.
Number of Customers	The larger the number of customers connected to the station, the higher the priority. For example, ancillary systems located at TSs are given higher priority than those located at MSs.
Failure Rate	Ancillary systems that have frequent SCADA alarms and have a history of repairs will be given higher priority. For example, air compressors that have had a history of problems like motors found smoking, leaking, low air pressure etc., will be prioritized.
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets to be replaced

E6.6.5 Options Analysis

E6.6.5.1 Reactive Replacement

A large portion of station assets are operating beyond their useful life and are obsolete, thus increasing the risk and the impact of failure. As more assets are replaced reactively, the redundancy of the distribution system will continue to degrade and customer outage times and customer outage frequency will increase. Failure rate is expected to increase as assets continue to age without replacement.

Under this option, Toronto Hydro would not perform asset renewal and instead accept the risk of asset failure. This option is therefore not considered and not recommended for stations assets which will be needed well into the future. Generally, this includes all station assets except those at Municipal Stations with voltage conversion plans.

E6.6.5.2 Risk-tolerant Asset Renewal

Under the risk-tolerant option, Toronto Hydro would maintain its 2015-2019 forecast spending and accept an incremental risk given that certain planned projects from 2015-2019 program were not executed.

To maintain spending comparable to its forecast 2015-2019 spending, Toronto Hydro would reduce TS Switchgear renewal plans, and maintain the same level of investment in Municipal Station Assets, and Battery and Ancillary Services (as they have not substantially changed).

The utility is unable to reduce the spend allocated to the Control and Monitoring segment beyond that that forecasted under its proposed plan for the 2020-2024 period due to the critical nature of the assets. Toronto Hydro's DACSCAN and MOSCAD RTUs are functionally obsolete and beyond their useful life and need to be replaced.

Therefore, with the exception of its TS Switchgear renewal plans, the risk-tolerant option is negligibly different from Toronto Hydro's proposed balanced option discussed in Section E6.6.5.4 below and outlined in the Expenditure Plan in Section 4. For this reason, only changes to the TS Switchgear segment are discussed.

1. Transformer Stations

Under the risk-tolerant option, Toronto Hydro would replace two TS switchgear units. With this limited investment, in 2024, 38 percent of Toronto Hydro's TS Switchgear will be operating beyond their useful life, an 11 percent increase from the current baseline of 27 percent. Operating a larger number of these critical assets past their useful life places more downtown customers at risk of outages due to asset failure. Furthermore, the risk would continue to grow because of the demographics are such that with this investment strategy, towards the middle of the 2025-2029, nearly half of Toronto Hydro's 51 TS Switchgear assets will be operating beyond their useful life

As a result, in future rate periods, Toronto Hydro would have to invest more than the entire proposed 2020-2024 Stations Renewal spend ($141.5 million) to reduce the number TS switchgears beyond their useful life to 2019 levels of 27 percent.

Furthermore, and highlighted by Toronto Hydro's historical progress in the TS segment, the complexity of TS Switchgear replacement projects limits the number of replacements Toronto Hydro can perform in a given rate period. Therefore, regardless of an increased budget in future rate periods, the utility would struggle to recover from the consequences of deferred investment now as continued investment deferral would further add to the already existing back-log.

E6.6.5.3 Voltage Conversion

This option is only applicable to work affecting MSs (i.e. Municipal Stations, Control and Monitoring, and Battery and Ancillary Systems Segments). Under the voltage conversion option, Toronto Hydro would decommission MSs with end-of-life and obsolete station assets, thereby eliminating the need for replacement.

For the following two reasons, this option is only pursued when the distribution assets outside the station have also reached end-of-life. First, voltage conversion is fundamentally a renewal option for distribution equipment. Second, the cost of voltage conversion is estimated to be 4 to 8 times the cost of replacing all the station assets. Therefore, voltage conversion only makes sense when justified by the need to renew distribution assets. Where this is the case, voltage conversion would be Toronto Hydro's preferred option. For more information regarding voltage conversion, please see the Area Conversions,[30] Overhead System Renewal,[31] and Underground System Renewal programs.[32]

E6.6.5.4 Balanced Asset Renewal (Proposed Option)

Under the proposed balanced asset renewal option, Toronto Hydro will only replace assets identified as presenting the greatest level of risk and only to the extent required to maintain system reliability. Furthermore, with respect to MSs, Toronto Hydro will only replace assets at stations not targeted for voltage conversion, since conversion will result in decommissioning of the station assets. Toronto Hydro's proposed 2020-2024 work plan is based on this balanced approach and is the recommended option.

A significant portion of Toronto Hydro's station assets have been identified to be at end-of-life and suffer from obsolescence issues. By planning asset replacements based on the needs and pacing detailed in Section E6.6.3, Toronto Hydro is able to reduce failure risk while adhering to resource limitations. This provides a positive outcome for customers by maintaining reliability at a reasonable cost. The targeted pacing also helps maintain sustainability in regards to long-term cost and resource requirements by preventing the number of assets past useful life from increasing beyond a manageable replacement rate.

[30] Exhibit 2B, Schedule E6.1
[31] Exhibit 2B, Schedule E6.5
[32] Exhibit 2B, Schedule E6.2 and E6.3

The pace proposed in this option is the ideal rate of replacement for the assets under this Program. It allows Toronto Hydro to address deteriorating and end-of-life equipment initially considered for the 2015-2019 period asset delayed due to external factors and delayed timelines in addition to the newly deteriorated and end-of-life assets. Therefore, to maintain the age profile of the assets to those in 2017, a slower pace should not be considered.

This option presents the best value to customers, and is consistent with the priorities they have identified: maintaining reliability and minimizing costs.

Toronto Hydro's balanced asset renewal plan with respect to each segment has been presented in detail in Section E6.6.3 and Section E6.6.4.

E6.6.5.5 Complete End-of-Life Asset Renewal

A significant portion of Toronto Hydro's station assets are operating beyond useful life, contain obsolescence related deficiencies, or have been assessed to be in poor condition. Under this renewal option, Toronto Hydro would strive to replace all assets that have reached or surpassed their useful life, in addition to all assets which have been identified as at end-of-life due to condition assessments or obsolescence. In doing so, this would allow the utility to offset past execution limitations.

Although ideal for increased reliability and operational effectiveness, this option is not recommended as it conflicts with customer priorities to contain cost and limit rate increases. It also risks investment in assets which are not required in the longer term. In reality, this option is limited by Toronto Hydro's execution capabilities and customers' price sensitivity.

1. Transformer Stations

This TS asset renewal option would include replacement of all assets operating beyond their useful life, all assets containing PCBs (e.g. KSO breakers), and all legacy assets (e.g. brick switchgear structures, air-blast circuit breakers, etc.).

With significant investment, in 2024, a limited amount of Toronto Hydro's TS Switchgear, TS Outdoor Breakers, or TS Outdoor Switches would be operating beyond their useful life. This would be a significant reduction from current baselines of 27 percent, 4 percent, and 31 percent, respectively.

However, Toronto Hydro would be unable to perform the volume of work required due to the pace required to achieve the desired level of reliability. Transformer station renewal work generally has long lead times, extensive resource requirement, and requires considerable outages. It is likely the volume of work could not be executed so quickly, highlighting the need to keep demographics within comfortable limits.

This option is not recommended for TS Switchgear, TS Outdoor Breakers, or TS Outdoor Switches due to the cost required relative to the expected return in reliability improvement and its conflict with customer priorities.

2. Municipal Stations

Under this option, asset renewal would include replacement of all station assets operating beyond their useful life or assessed to be in poor condition.

With significant investment, none of Toronto Hydro's MS switchgear, power transformers, or MS primary supplies would be operating beyond their useful life. This would be a significant reduction from current baselines of 43 percent, 46 percent, and 77 percent respectively.

However, Toronto Hydro would be unable to perform the volume of work required due to the pace required to achieve the desired level of reliability. Municipal station renewal work has lead times on the order of months to over a year, extensive resource requirement, and requires considerable outages. The volume of work required would be 550 percent, 750 percent, and 750 percent of the volume proposed in the balanced asset renewal option for the MS switchgear, power transformers, and MS primary supply assets respectively. This volume of work could not be executed to achieve the objective of this option, which only highlights the need to keep demographics within reasonable limits.

This option is not recommended for MS switchgear, power transformers, or MS primary supplies due to the prohibitive cost required relative to the expected incremental return in reliability. Such a result would strongly conflict with customer priorities to manage costs.

3. Control and Monitoring

Under this option, asset renewal for Control and Monitoring systems would including replacing all RTUs operating beyond their useful life, replacing all electromechanical pilot-wire relays, and replacing all copper control circuits.

With large investments, none of Toronto Hydro's RTUs would be operating beyond their useful life. This would be a significant reduction from current baseline of 37 percent. Toronto Hydro would convert all electromechanical pilot-wire systems to differential protection systems and align itself with the new industry standard for critical line protection. This would provide its customers who value reliability above all else with the assurance they have the most reliable system that is feasible. Additionally, the utility would replace all copper control circuits with fiber and align itself with the new industry standard for hard-wired communication systems. This would reduce communication channel failure and the remove the risks that arise from it.

This option is not recommended for RTU renewal, pilot-wire renewal, or copper renewal due to the prohibitive cost and labour resources required. Toronto Hydro would be unable to achieve the execution pace required as the volume of work is simply too large. Additionally, the costs of this alternative would be too high thus contradicting customer desire for cost management.

4. Battery and Ancillary Systems

Under this alternative, asset renewal would include replacing all battery and ancillary systems assets operating beyond their useful life, or containing PCBs.

With significant investment, in 2024, Toronto Hydro would have no DC battery and charger systems, station service transformers, or air compressors operating beyond their useful life. This would be a significant reduction from current baselines of 22 percent, 26 percent, and 20 percent, respectively. Additionally, this would eliminate the risk of PCB release into the environment due to this asset class (as 9 percent of these units currently contain PCBs).

Despite smaller lead times relative to other segments, this option would require an asset renewal pace that surpasses Toronto Hydro's execution limitations. In addition, investments in battery and ancillary systems can be most easily mitigated via operational practices (compared to other segments).

This option is not recommended for DC battery and charger systems, station service transformers, or air compressors due to the required investment required relative to the expected incremental return in reliability.

E6.6.6 Execution Risks & Mitigation

Each segment of the Stations Renewal program faces challenges which can delay or prevent planned renewal work from occurring. Many of these challenges overlap across the four segments of this Program. These challenges are summarized in the table below.

Table 53: Execution Risk Applicability by Segment

Segment	Execution Risks						
	Resource Constraints	Planned outages	Asset Failures	Procurement Lead Times	Project Assessment	Distribution Coordination	Other Risks
Transformer Stations	✓	✓	✓	✓	✓	✓	✓
Municipal Stations	✓	✓	✓	✓	✓	✓	✗
Control and Monitoring	✓	✓	✗	✗	✓	✗	✓
Battery and Ancillary Systems	✓	✓	✓	✗	✓	✗	✗

E6.6.6.1 Resource Constraints

All four segments of the Stations Renewal program use the same pool of stations design and construction resources. Therefore, if there are insufficient resources to complete all the projects planned in the Program, then certain projects will need to be deferred to ensure highest priority projects are completed. Prioritization of projects within this Program is discussed in Section E6.6.4. Toronto Hydro is mitigating this risk with the help of third party providers to complete any projects in excess of Toronto Hydro's resource capacity.

E6.6.6.2 Planned Outages

Most of the renewal work cannot be completed unless a planned outage is arranged. Planned outages are needed to de-energize feeders, power transformers, switchgear, or entire stations without causing power outages to customers, so that Toronto Hydro's crews can safely complete replacement or maintenance work. For Toronto Hydro to de-energize station assets without introducing any undue risk of power outages, Toronto Hydro cannot execute multiple planned outages within the same TS or at two neighbouring MSs. Additionally, projects occurring at neighbouring MSs are planned to take place in different years, and if possible, at least two years apart.

E6.6.6.3 Asset Failures

Failure of station assets are a source of unplanned station outages which can prevent replacement projects from proceeding due to lack of redundancy. This risk can be mitigated by proactively replacing end-of-life station assets in a timely manner as proposed in this Program.

E6.6.6.4 Procurement Lead Times

Procurement lead times for power transformers, MS switchgear, and TS switchgear range from 6 to 18 months. For this reason, it is difficult and sometimes infeasible to advance or expedite the replacement of a station asset, even if such a change in schedule would result in a more effective execution of the Program. To help mitigate this risk, Toronto Hydro orders this equipment 6-18 months or earlier in advance of expected in-service dates.

E6.6.6.5 Distribution Coordination

Distribution coordination is a challenge commonly affecting the TS and MS segments. All TS switchgear replacement projects and all projects under the MS segment require a distribution project to support the replacement of station assets. A switchgear replacement requires distribution feeders to be removed from the old switchgear and connected to the new switchgear, and replacement of the primary cable within a MS is completed through a distribution project. As a result, if there are delays or resource constraints in the distribution projects, then dependent station projects may also be delayed. Similarly, distribution projects also require planned outages as discussed earlier.

To mitigate the risk relating to distribution coordination, Toronto Hydro engineers strive to clearly define the need for coordination between station and distribution projects at the inception of such projects. On this basis, project managers plan interdependent projects as a single entity so that adequate resources can be allocated and adequate outage planning can be initiated.

E6.6.6.6 Project Assessment

All planned work undergoes a risk assessment by Toronto Hydro’s control centre prior to execution. This timeframe is accounted for in the pacing outlined in section E6.6.4.

E6.6.6.7 Other Risks

The risks identified below apply only to their specific segments.

1. Hydro One Coordination (TSs)

One of the most significant risks for the successful completion of projects under the TS segment will be Toronto Hydro's ability to effectively coordinate with Hydro One. For example, when replacing a TS switchgear, close coordination is required to transfer Hydro One's supplying transformers from the existing switchgear to the new switchgear. For TS outdoor breaker replacements, all protection and control wiring needs to be verified by Hydro One prior to the breakers being placed back in-service.

With this need for coordination, there is always a risk Hydro One might not be able to secure resources to align with Toronto Hydro's work plan. Additionally, similar to the discussion in Section E6.6.6.2, Hydro One also requires that its own equipment undergo planned outages. Given the need for such planned outages, there is a risk that Toronto Hydro's replacement work will be prevented from proceeding due to a lack of redundancy.

Toronto Hydro mitigates this risk by sharing its high-level replacement plans with Hydro One years in advance of planned project start date. As project execution draws closer, Toronto Hydro and Hydro One exchange detailed information and communicate more frequently to ensure that work plans and resourcing aligns for both companies. For more information, see Exhibit 2B, Section B.

2. Physical Constraints (TSs)

Space limitations pose a significant risk to the timely completion of TS switchgear renewal projects under the TS segment. In many cases, Toronto Hydro stations do not have space available to install new switchgear. This is a problem because it is usually necessary to install a new switchgear before decommissioning the existing unit, so as to maintain continuous power supply to customers.

The alternative to this approach is to transfer all customers from the existing switchgear to an adjacent switchgear, decommission the existing switchgear, and then install the replacement in the same space. This can only be done if the adjacent switchgear has enough spare capacity to supply these additional customers. Spare capacity on this order is seldom available.

Toronto Hydro mitigates this risk through use of its Station Expansion program,[33] which is intended to ensure capacity requirements are met on the distribution system. Notably, the construction of Copeland TS Phase 1 and Phase 2 will facilitate the replacement of switchgear units at Windsor TS (and other downtown stations in the future). For example, replacement of the Windsor TS A5-6WR switchgear unit will be possible once Copeland TS – Phase 1 has been energized, following which the electrical load on the Windsor TS A5-6WR switchgear will be transferred to the Copeland TS A1-2CX switchgear. Thereafter, A5-6WR can be decommissioned and its space used to install a new switchgear. This in turn will allow capacity for the next Windsor TS switchgear unit to be replaced.

By ensuring a reasonable level of spare capacity at or adjacent to heavily loaded stations, Toronto Hydro will be able to effectively plan and execute switchgear replacement while accommodating new customer connections.

3. Customer Coordination (Control and Monitoring)

For pilot-wire system replacements under the Control and Monitoring segment, a challenge to successful execution is customer coordination. Such replacements require customer relays and associated equipment to be replaced in parallel with Toronto Hydro’s equipment. This introduces a risk since projects cannot be scheduled until a time is found which satisfies both the customer’s and Toronto Hydro’s needs. Toronto Hydro minimizes this risk by informing customers several months ahead of planned work, allowing sufficient time for customers to respond and schedule a time that is feasible.

[33] Exhibit 2B, Schedule E7.4

E6.7 Reactive and Corrective Capital

E6.7.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 267.3	**2020-2024 Cost ($M):** 317.2[1]
Segments: Reactive Capital; Worst Performing Feeders	
Trigger Driver: Failure	
Outcomes: Reliability, Safety, Environment and Customer Service	

The Reactive and Corrective Capital program (the "Program) addresses the replacement of failed and defective assets, and provides for near-term corrective actions on Toronto Hydro's least reliable feeders. The work required under this Program is urgent and non-discretionary. Toronto Hydro carries out the projects and activities in this Program in response to: (1) asset failures, (2) high risk asset deficiencies discovered through planned inspection or in the course of day-to-day work, and (3) feeders exhibiting especially poor reliability.

The Program is grouped into two segments summarized below, and is a continuation the reactive and corrective activities described in Toronto Hydro's 2015-2019 Distribution System Plan.[2]

- **Reactive Capital:** this segment covers the non-discretionary replacement of failed or failing assets across the entire system. Although Toronto Hydro's distribution system has experienced improved reliability overall, there is a significant number of asset failures each year. Between 2013 and 2017, there were approximately 3000 Customer Interruptions ("CI") and 2,300 Customer Hours Interrupted ("CHI") associated with major asset failure across the network. Catastrophic failures of assets can require very large investments by Toronto Hydro – investments that, in the absence of a dedicated reactive capital budget, would deprive other capital and operational programs of resources necessary to maintain the grid. The objective of this segment is to manage unavoidable asset failures and address high-risk deficiencies (or assets approaching imminent failure) in a timely and cost- effective manner to mitigate the impact of failures on customer outcomes such as reliability, safety and the environment for 2020 to 2024 and beyond.

[1] Consistent with the 2015-2019 program, the 2020-2024 program forecast includes allowances for streetlight reactive pole replacement, reactive streetlight replacement and streetlight spot improvement
[2] EB-2014-0116, Exhibit 2B, Section E6.20

- **Worst Performing Feeders:** this segment focuses on improving overall service reliability for customers supplied from poorly performing feeders. The objective of this segment is to identify feeders at risk of experiencing seven or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of 7 of more, or "FESI-7") over a 12-month rolling period and perform mitigation work on deficient assets that could lead to additional interruptions. Although relatively few in number when compared to non-FESI feeders, FESI feeders have a disproportionately negative impact on the system's overall reliability performance. FESI-7 feeders have contributed, on average, to 25 percent of the annual customer interruptions ("CI") and 23 percent of customer hours interrupted ("CHI") since 2013. In response to the reliability and resiliency needs of Toronto Hydro's large customers, and in addition to the FESI-7 metric, the utility has introduced a similar FESI-6 metric specifically for feeders that serve Large Commercial & Industrial class customers across the system.

As the nature of work in this Program is largely unplanned, unpredictable, and can vary significantly from year to year, Toronto Hydro has based its 2020-2024 forecast costs and projected reactive work volumes for this Program on historical trends. The utility forecasts $317 million for the Program during the 2020-2024 period, which is approximately 18 percent increase over projected 2015-2019 spending (including forecasted inflation). Timely reactive work improves safety, avoids depriving other capital programs of planned resources, mitigates environmental impacts, and reduces strain on the distribution system.

E6.7.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service obligations and objectives, including the accurate billing of all smart metered customers based on actual usage (also supports compliance with the *Electricity and Gas Inspection Act* and the *Weights and Measures Act*) by restoring metering service as soon as possible.

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, System Health (poles)) by: ○ Promptly replacing assets that have failed or are at a very high risk of near – term failure; and ○ Monitoring feeders that are at a high risk of becoming FESI-7 or, for Large Customers, FESI-6, and taking near-term mitigating actions where feasible.
Safety	• Contributes to maintain Toronto Hydro's Total Recorded Injury Frequency measure and safety objectives including TRIF (including compliance with Ontario Regulation 22/4) by replacing failed assets (or high-risk assets approaching imminent failure) to mitigate the risk of catastrophic asset failure events causing injuries to utility employees or members of the public.
Environment	• Contributes to environmental impact reduction of Toronto Hydro's distribution system by avoiding the potential release of harmful chemicals, smoke, or waste (e.g. oil leaks) into the environment through timely replacement of failing or failed assets. • Contributes to improving the Spills of Oil Containing PCBs measure through continuously reducing PCB-contaminated oil leaks by eliminating assets at risk of containing PCBs.[3]

E6.7.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure
Secondary Driver(s)	Reliability , Safety, and Environmental Risk

The Reactive and Corrective Capital program is largely driven by the need to address equipment failure. The Program is focused on ensuring assets and system perform at an acceptable standard by: (i) addressing asset deficiencies and failures through like for like replacements; and (ii) executing short term, targeted and small scale mitigation measures to reduce the risk of additional outages on feeders exhibiting poor reliability outcomes. The need for the Reactive Capital segment must be addressed in short order mainly due to asset failure risk, and the Worst Performing Feeders segment

[3] In recent years (2015-2017), the program has replaced an average of 120 transformers per year that contained or were at risk of containing PCBs.

aims largely to improve overall service reliability for customers supplied from poorly performing feeders.

Through the proposed Program, Toronto Hydro would be better able to maintain system performance and reliability, customer satisfaction, and manage or eliminate safety risks to the public and Toronto Hydro employees. The trigger and secondary drivers for this Program are discussed below.

E6.7.3.1 Failure Risk

As the trigger driver of the Reactive and Corrective Capital program, asset failure on Toronto Hydro's distribution system presents reliability risks (which can lead to outages and directly impact customers), environmental risks (e.g. oil spills into the environment), and safety risks (e.g. stemming from electrical contacts, arc flashes, and potentially catastrophic fires). Timely replacements are required to avoid the distribution system being operated under contingency conditions (i.e. with a lack of feeders or assets that can provide backup supply in the event of a subsequent outage).

Table 4 shows the customer reliability impacts of major asset failures between 2013 and 2017. Each failure of overhead switches for example, caused 805 customer interruptions and 359 customer hours of interruption on average between 2013 and 2017.

Table 4: Average CI and CHI Associated with Failures of Major Assets from 2013 - 2017

Asset	Customer Interruptions (CI)	Customer Hours Interrupted (CHI)
Overhead Switches	805	359
Overhead Transformers	190	112
Poles	770	739
Underground Cables	766	729
Underground Transformers	302	292

Timely replacement of failing equipment before an imminent failure can mitigate the frequency and duration of interruptions experienced by the customer. Although Toronto Hydro's distribution system has experienced improved reliability overall, there is a significant number of asset failures each year. Various factors can cause failure including degradation of an asset's condition, foreign interference, and weather. As examples,

Figure 1 shows: (i) a fractured pole caused by a vehicle accident (i.e. foreign interference); and (ii) structural deficiencies of an underground vault as a result of gradual degradation.

Figure 1: Motor vehicle accident on distribution pole (left), underground vault structural deficiencies (right)

Age and condition can also affect the health of an asset, and contribute to asset failure. As an example, Table 5 summarizes Toronto Hydro's Asset Condition Assessment ("ACA") results for underground submersible transformers, which indicate: (i) 227 submersible transformers exhibit material deterioration (HI4 & HI5) and should be considered for replacement as of the end of 2017; and (ii) without any intervention, the number of transformers exhibiting material deterioration is forecasted to more than double by 2024 (554 major assets).

Table 5: Asset Condition for Submersible Transformers[4]

Condition	Submersible Transformers	
	2017	**2024**
HI1 - New or Good Condition	7,816	7,447
HI2 – Minor Deterioration	588	364
HI3 – Moderate Deterioration	271	537
HI4 – Material Deterioration	172	143
HI5 – End of Serviceable Life	55	411
Total	**8,902**	**8,902**

[4] For more details on Asset Condition Assessment see Exhibit 2B, Section D, Appendix A.

Furthermore, as of 2017, 14 percent of Toronto Hydro's overhead transformers have surpassed their useful life and, without any replacement, this is expected to more than double by 2024. With this higher number of end-of-life assets in the system there is a greater likelihood of failure and need for reactive replacement.

Detailed discussions of the condition and age demographics of various asset classes are provided under Toronto Hydro's System Renewal programs.[5]

1. Safety

Another important driver of the Program is the safety and health of both the public and Toronto Hydro employees. Failure modes of equipment, depending on their nature, can have immediate and serious safety and health consequences. For example, transformers in deteriorated condition may experience transformer fires. Overhead lines with cracked or damaged insulators may lead to pole fires. Such fires pose serious risk to workers and the public. Similarly, civil failures and the collapse of structures (such as poles and vaults) can jeopardize the public and Toronto Hydro employees. The Reactive Capital segment can mitigate safety and health risks by replacing assets that have failed or are approaching imminent failure. As examples, Figure 2 below illustrates a pole fire and hazardous conditions found in a network vault.

Figure 2: Pole fire caused by Tracking (left), exposed and rusted rebar in Network Vault (right)

[5] Exhibit 2B, Section E6

2. Environment

Asset failures can also be harmful to the environment. Leaking transformers or cables in underground structures pose a serious environmental risk. Asset failures can also result in the release of harmful contaminants and greenhouse gases into the environment. Timely capital replacements help mitigate such environmental risks. The Reactive Capital segment addresses oil deficiencies by replacing leaking transformers. As an added benefit, during transformer replacement, assets that are at risk of containing PCB are also replaced, thereby reducing the possibility of oil spill containing PCBs.

3. Reliability

Finally, reliability is an important driver of the Program. Depending on the asset and its location within the distribution system, system reliability will be negatively impacted by an asset failure. Asset failures affect the supply of power to Toronto Hydro's customers and strain the system. Historical system reliability impacts are discussed in detail for each segment below.

E6.7.3.2 Reactive Capital

The Reactive Capital segment is comprised of work relating to overhead, underground, secondary network, stations and metering assets. The purpose of this reactive work is to restore service to customers and maintain system reliability by addressing severe asset deficiencies and failures. Reactive work occurs on an unplanned basis in response to an asset failure or the detection of a high risk asset deficiency (e.g. a severely cracked pole). Such issues cannot be addressed by planned capital renewal procedures and timelines, and therefore, must be reactively replaced to maintain the safety and reliability of the distribution system. Reactive work is executed within a short timeframe (e.g. one day to six months) following the detection of an asset requiring replacement. Reactive work covers Toronto Hydro's entire distribution system and affects all asset classes.

Asset deficiencies or substandard conditions across Toronto Hydro's distribution system are identified mainly through the Preventative and Predictive Maintenance programs, but can also be identified either during the normal course of operations or through the Emergency Response program, as shown in Figure 3 and explained in more detail below. Identified deficiencies or substandard conditions are subsequently addressed through a variety of programs: Preventative and Predictive Maintenance, Corrective Maintenance and the Reactive and Corrective Capital programs.[6]

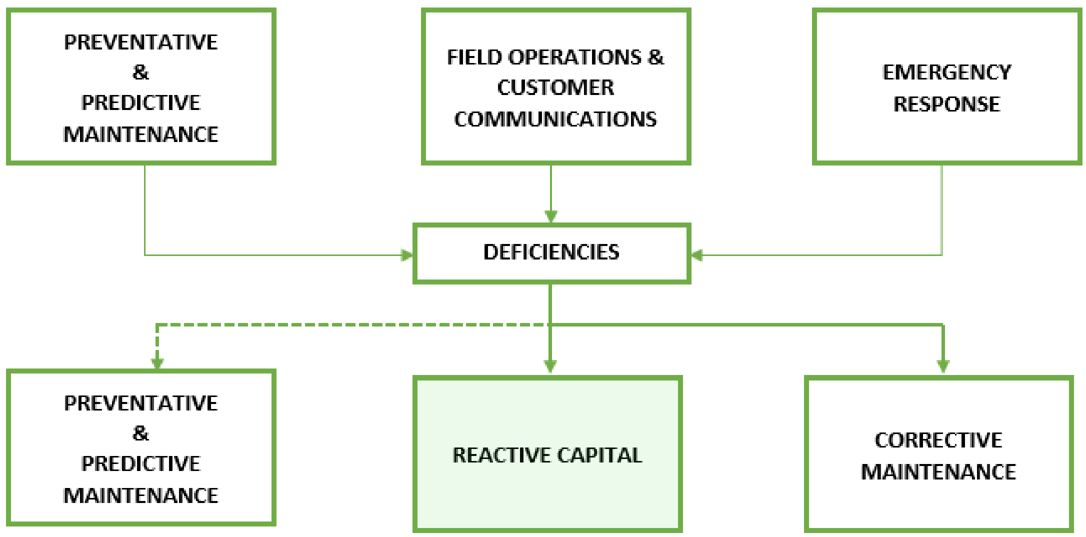


Figure 3: Deficiency Capturing Process[7]

- **Preventative & Predictive Maintenance Activities**: Toronto Hydro's field crews identify asset failures and deficiencies as part of scheduled maintenance and inspection activities.
- **Field Operations & Customer Communications**: issues or actions identified under this category include meter errors collected through Internal Data Collection Systems, phone calls from the customer service team, external emails, and observations by the field crew during the normal course of operations, and customer enquiries requiring field assessment and follow up.
- **Emergency Response:** reactive capital work can also be required as a result of emergencies or unplanned system events. These include asset failures and deficiencies identified outside of Toronto Hydro's daily (planned) operations but requiring immediate remediation and reactive replacements in order to restore power or eliminate safety or environmental risks.

Deficiencies from the above sources are: (i) reviewed to validate the need for reactive intervention; (ii) assessed to determine the nature of reactive intervention required (capital versus maintenance);

[6] Exhibit 4A, Tab 2, Schedules 1-4 for maintenance programs
[7] The deficiency capturing process is described in detail in Exhibit 2B Section D3.

and (iii) the level of urgency/priority to be assigned to each asset deficiency. Toronto Hydro addresses the deficiencies by issuing work requests.[8]

Due to the unpredictable nature of asset failures, the number of corrective work requests from year to year may vary. Catastrophic failures of assets can require very large investments by Toronto Hydro – investments that, in the absence of a dedicated reactive capital budget, would deprive other capital and operational programs of resources necessary to maintain the grid. As such, Toronto Hydro requires the Reactive Capital segment to manage unavoidable asset failures and address high-risk assets approaching imminent failure, in order to continue to provide reliable, safe, and environmentally responsible service to customers from 2020 to 2024 and beyond.

Figure 4 below shows the volume of reactive capital work requests issued between 2013 and 2017.

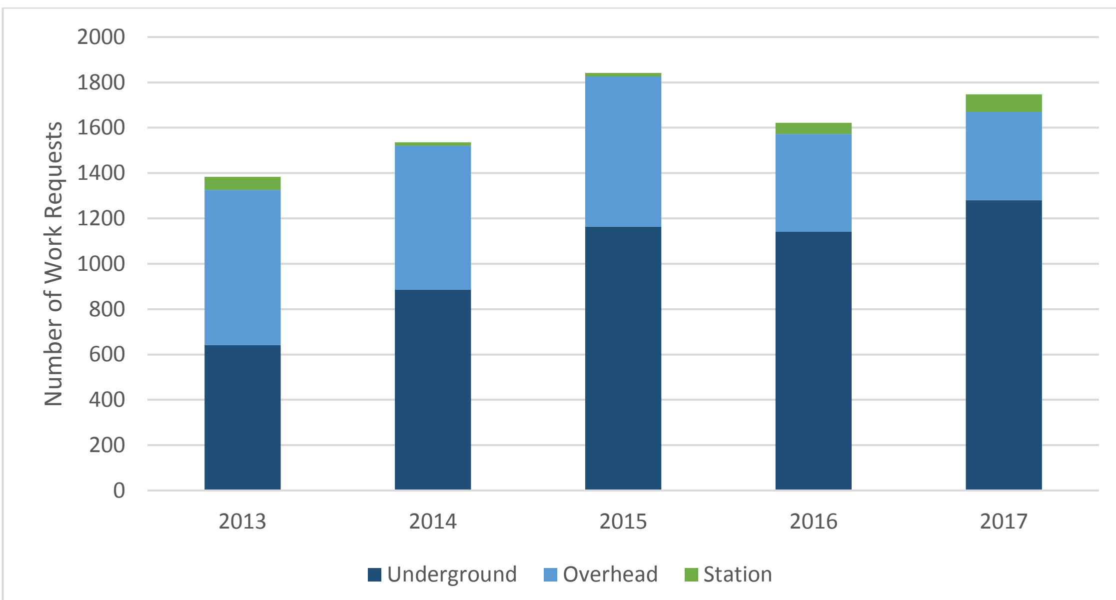


Figure 4: 2013 - 2017 Total Number of Reactive Capital Work Requests by System Type

As shown in Figure 4 above, Toronto Hydro has seen an overall rise in the number of work requests issued to address reactive capital work, primarily due to underground assets with deteriorating age and condition as discussed in the Underground System Renewal programs. Within the stations environment, the volume of requests has varied, but due to the size, operational complexity, and

[8] Work request are forms issued to assign / schedule corrective work addressed by Toronto Hydro crew. Deficiencies identified and work requests raised may have a one to one or many to one relationship (i.e. a single work request may contain more than one deficiency)

criticality of stations assets, station work can contribute significantly to the overall cost of the Reactive Capital segment, despite the relatively low volume of requests.

1. Metering Assets

The Reactive Capital segment also funds reactive meter replacement. Reactive meter replacement capital work consists of the replacement of defective metering equipment in the field including: smart meters, suite meters, interval meters, and primary meters (Including instrument transformers). The loss of communication with a meter is the primary cause of meter replacements. Primary metering units can also fail due to blown instrument transformer fuses which causes customer consumption to be incorrectly read, resulting in incorrect billing. Failed metering equipment not replaced in a timely manner can result in delayed billing and the need to estimate customer consumption.

Table 5 summarizes the estimated number of reactive meter replacements and their estimated costs for the 2020-2024 filing period. The estimated volumes were derived using historical meter failure rates. The year over year increases are due to projected increases in Quadlogic meter failures as the Quadlogic meter population in Toronto Hydro's service area grows. The average percentage of meters failing remains the same but the population is increasing yearly. The meter replacement costs are embedded into the Reactive Capital segment 2020-2024 forecasts in the Expenditure Plan section.

Table 5: Reactive Meter Replacements and Costs (2020 - 2024)

	Projected					
	2020	2021	2022	2023	2024	Total
Meter Replacements (Units)	5585	5685	5785	5885	5985	28925
Meter Replacement Costs ($ Millions)	2.28	2.30	2.33	2.35	2.38	11.64

E6.7.3.3 Worst Performing Feeders

Toronto Hydro's distribution system contains more than 1,500 feeders that supply power to over 700,000 customers in the City of Toronto. While any one of these feeders is subject to random equipment break-down, foreign interference and environmental effects that can cause unplanned outages, specific feeders experience a disproportionate number of problems and cause an unacceptably high number of sustained interruptions to the residential and commercial customers connected to them. The Worst Performing Feeder ("WPF") segment employs a feeder level analytical approach that selects feeders experiencing a high number of outages or trending towards increased outages for analysis to determine the cause of outages.

The main objective of Toronto Hydro's WPF segment is to improve overall service reliability for customers supplied from poorly performing feeders. Through this segment, Toronto Hydro identifies feeders which are at risk of experiencing seven or more sustained interruptions over a 12-month rolling period (i.e. FESI-7), excluding planned outages, major event days, outages caused by loss of supply, and interruptions on the secondary side of the distribution transformer. Also, in response to reliability and resiliency needs, the number of sustained interruptions on feeders supplying Toronto Hydro's large customers that are more sensitive to outages (i.e. Commercial and Industrial customers) is reduced to six (i.e. FESI-6). This allows Toronto Hydro to closely monitor these large load feeders and intervene when required, and overall manage the disproportionately negative impact FESI-6 and FESI-7 feeders have on overall system reliability. Despite being relatively few in number compared to the non-FESI feeders, FESI feeders have contributed on average since 2013, about 25 percent of the annual system customer interruptions ("CI") and 23 percent of customer hours interrupted ("CHI").

About 49 percent of outages reviewed during a WPF reliability analysis were caused by defective equipment, and 28 percent by sources outside of Toronto Hydro's control (e.g. animal contacts, severe weather) as shown in Figure 5 below.

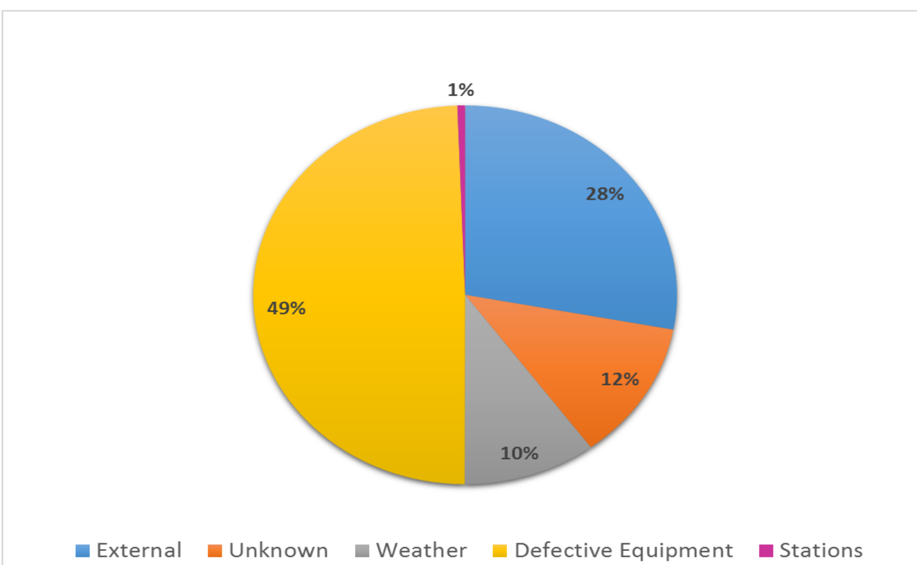


Figure 5: Causes of Sustained Feeder Outages

Following a feeder reliability analysis, field crews patrol and inspect these feeders to assess the condition of equipment and identify quick targeted actions that yield immediate reliability improvements. Some of the deficiencies discovered during these feeder patrols are shown in Figure 6 below.

Figure 6: Rusted Overhead Transformers at Risk of Leaking Oil (Left)/Animal Contact on Metal Switch Bracket (Right)

Figure 7 below shows the historical count of FESI-7 and large load FESI-6 feeders per year. As shown, the annual number of FESI-6 and FESI-7 feeders is small (less than 60) relative to the over 1,500 feeders that make-up Toronto Hydro's distribution system.

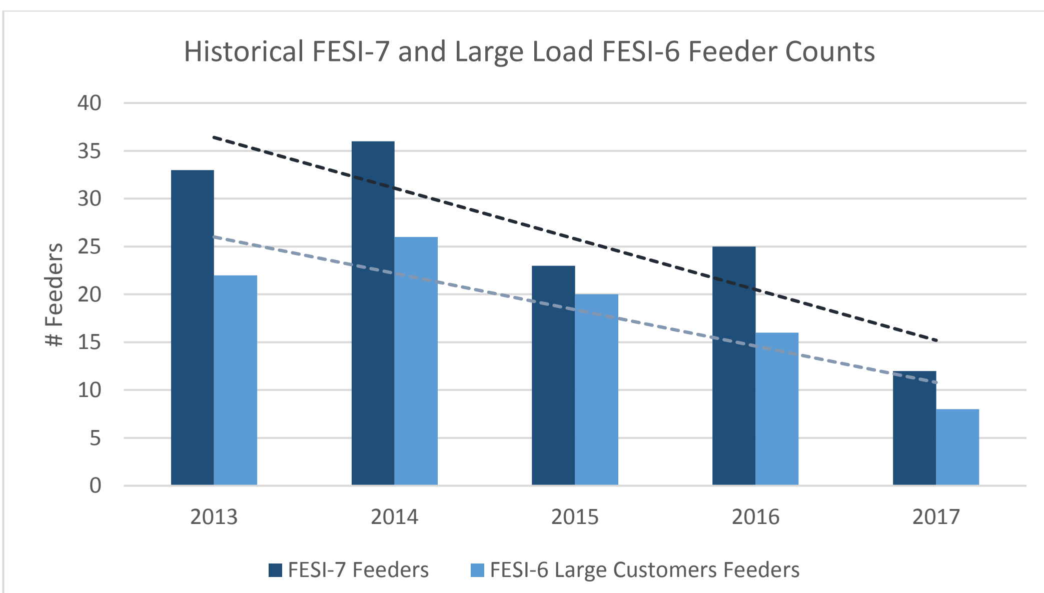


Figure 7: Historical Worst Performing Feeders

As noted above, these feeders have a disproportionately negative impact on the system's overall reliability performance. FESI-7 feeders have contributed, on average, to 25 percent of the annual CI and 23 percent of customer hours interrupted CHI since 2013. Figure 8 shows a comparison of CI and CHI on FESI-7 feeders to non-FESI feeders.

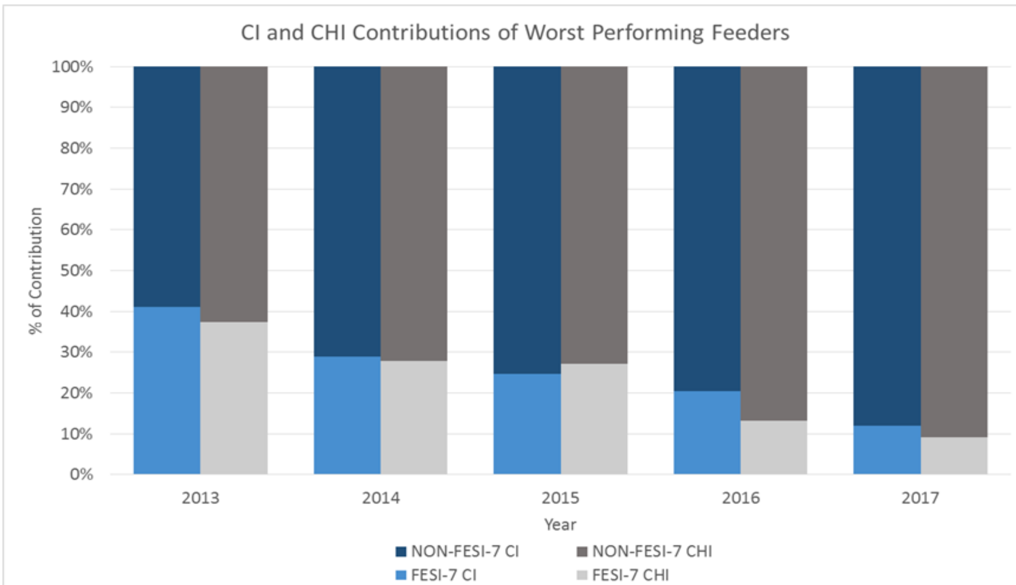


Figure 8: WPF – CI and CHI Contribution

Toronto Hydro has observed improvements to system reliability following the commencement of the WPF segment. As shown in Figure 8, the number of FESI-7 feeders has been trending down since 2013 and there has been a corresponding reduction of approximately 45 percent overall in the cumulative outages on FESI-7 feeders between 2015 and 2017.

The maps that follow compare the locations of large load FESI-6 feeders in 2015 and 2017. WPF mitigation work has led to noticeable improvement in the number of outages that this group of feeders experience in a given year.

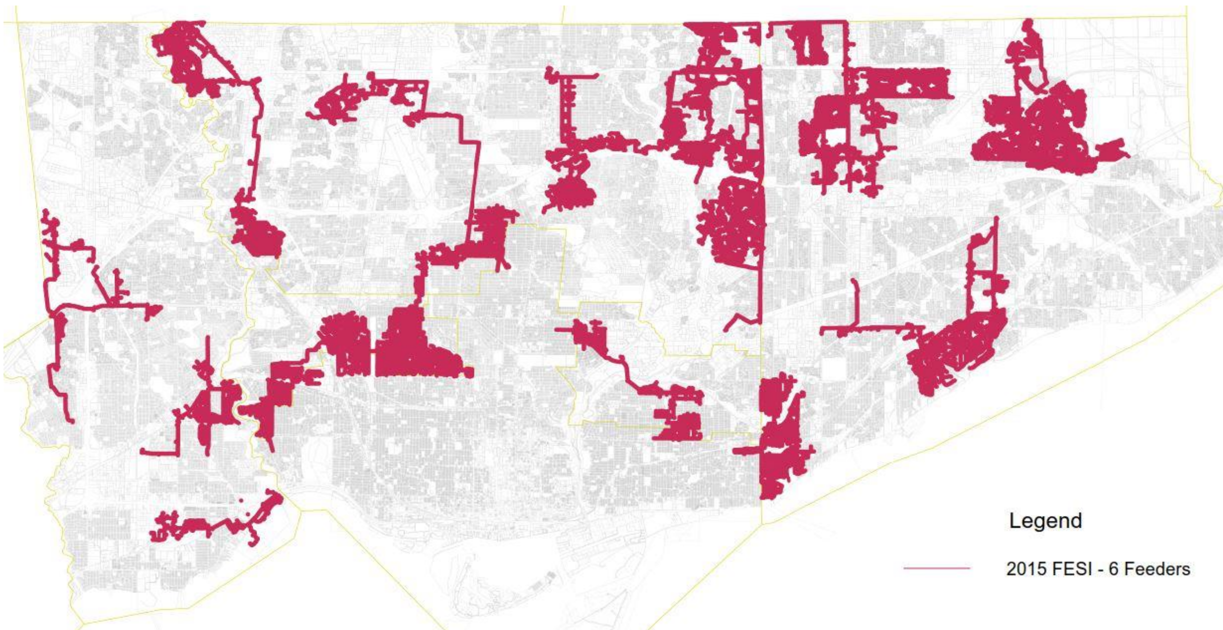


Figure 9: Locations of 2015 FESI-6 Feeders

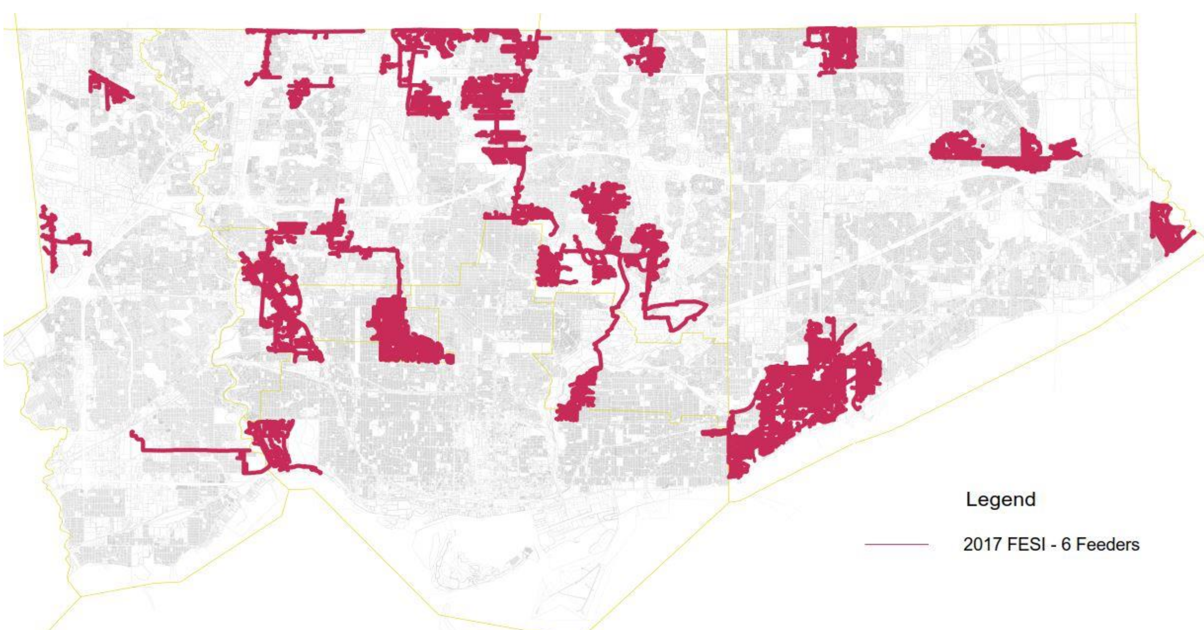


Figure 10: Locations of 2017 FESI-6 Feeders

The WPF segment is designed to be a short term mitigation measure and a complement to the planned renewal capital work. Feeders addressed by the WPF segment still experience unpredictable failure and power outages, albeit at a lesser frequency until permanent, long-term solutions are implemented. Overall, the WPF segment has been successful in reducing the frequency of power interruptions for customers on feeders that are experiencing especially poor reliability performance.

E6.7.4 Expenditure Plan

Table 6 provides the Historical (2015-2017), Bridge (2018-2019) and Forecast (2020-2024) expenditures for the Reactive and Corrective Capital program.

Table 6: Historical and Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Reactive Capital	39.0	50.2	52.5	54.4	52.6	56.4	57.5	58.5	59.4	60.7
Worst Performing Feeder	3.0	4.1	3.0	4.0	4.5	4.8	4.9	5.0	5.0	5.2
Total	**42.0**	**54.3**	**55.5**	**58.4**	**57.1**	**61.2**	**62.4**	**63.5**	**64.4**	**65.8**

E6.7.4.1 Reactive Capital Segment

Toronto Hydro invested $141.7 million in reactive capital work between 2015 and 2017, and projects to invest $248.7 million by the end of 2019 (approximately $83 million more than the 2015 -2019 forecast of $165.5 million).

The expenditures for Reactive Capital are forecasted based on historic trends in work requests volume and types, equipment failures and reliability. Given the nature of the Reactive Capital segment, actual work volumes and costs vary from year to year. The forecasts for 2015-2019 were developed in early 2014 and represented Toronto Hydro's forecast based on best available information at the time.

The predominant driver for the variance for the 2015-2019 period is that the actual volume and type of assets requiring non-discretionary replacement differed from forecast. This was unavoidable given the unpredictable nature of asset failures and volatile swings in the type and number of equipment failures from year to year. More specifically:

- The increase in reactive capital spending from 2015 to 2016 was driven by a higher number of replacements of underground transformers due to deficiencies such as oil leaks and corrosion. In 2016, Toronto Hydro replaced 601 underground transformers compared with

356 in 2015. A significant portion of the reactive capital spend between 2015 and 2017 was on the replacement of underground transformers, representing approximately half of the reactive capital underground work requests over the same period. This increase has been sustained in 2017 and is expected to be maintained.

- Reactive metering spending increased in 2017 due to a larger quantity of smart meters and suite meters failing, which can be attributed to a larger portion of the metering population being on time-of-use metering and the overall meter population getting older.
- The projected 2018 capital budget is driven by the expected reactive replacement of 353 distribution poles that were condemned based on preventative and predictive maintenance inspections. Historically, Toronto Hydro reactively replaces approximately 200 condemned poles per year.

Toronto Hydro's 2020-2024 forecast for expenditures and work volume under the Reactive Capital segment was based on historical trends, with a total of $292.4 million expenditure forecast over the period and an average annual reactive capital work request volume of 1,700, as shown in Figure 11.

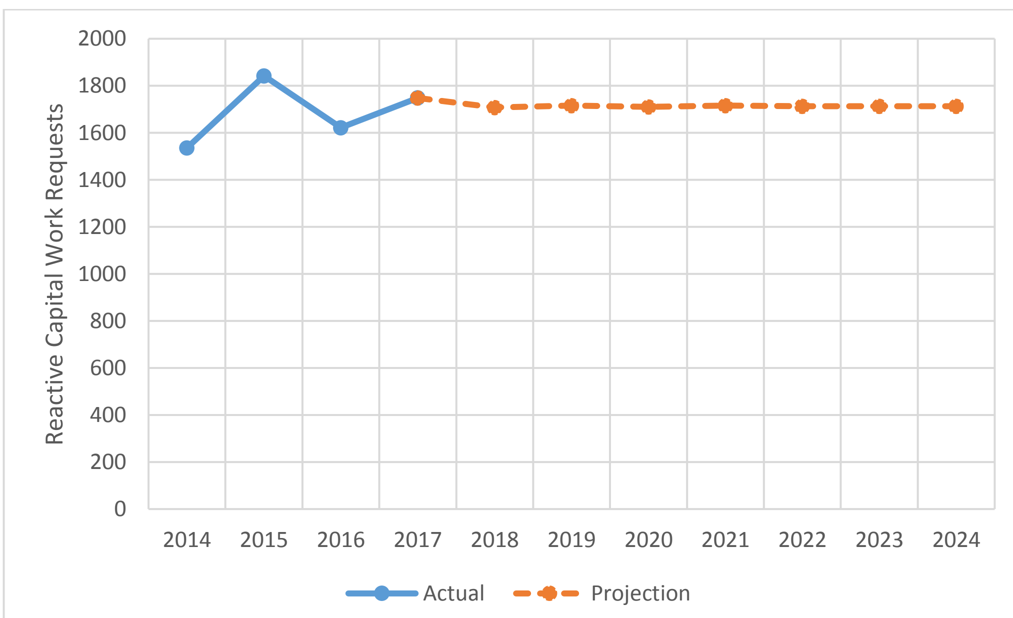


Figure 11: 2018-2024 Reactive Capital Work Request Forecast

As noted in Section 1, the nature of work in this segment is unplanned, unpredictable, non-discretionary, and can vary significantly from year to year. As a result, Toronto Hydro has based the forecast costs and projected work request volumes on historical expenditures and volume of work requests, using a moving average forecasting methodology. The 2020 to 2024 forecast (cost and volume) is relatively stable and consistent with historical spend.

For the Reactive Capital segment, Toronto Hydro uses a prioritization framework that classifies asset deficiencies into four categories: (i) P1 requires resolution within 15 days; (ii) P2 requires resolution within 60 days; (iii) P3 requires resolutions within 180 days; and (iv) P4 which indicates that conditions are to be monitored and work to be considered at a later date. When an asset exhibiting severe deficiencies is found through maintenance inspections, reported by operations teams or customers, or caused by emergency events, the utility immediately assigns personnel to triage and resolve the issue. Based on the expertise and experience of Toronto Hydro engineers and operation teams, deficiencies are evaluated and prioritized for resolution. Crews are then dispatched to address those assets with the highest safety and environmental risks first, followed by assets with the greatest impact on system reliability.

Contracts with service providers have been negotiated to include rates for both planned and reactive work. When project scheduling allows, P3 reactive work is “bundled” for efficiency purposes and issued as lower-cost planned work (which have lower unit prices). By doing this Toronto Hydro can avoid premium rates attached to reactive work.

Since 2015 Toronto Hydro has also undertaken efforts to maximize the productivity, safety, reliability, and environmental benefits of reduced switching work on the downtown “grid” system. Where possible for P1 and P2 work types, planned maintenance, customer or capital work can be bundled together to align with feeders that are taken out of service to create a safe work zone for repairs or equipment replacement and reduce the required switching costs. Due to lower urgency and more flexible turnaround times, P3 work can be aligned with upcoming maintenance, capital, or customer work.

E6.7.4.2 Worst Performing Feeder Segment

During the 2015-2017 period, Toronto Hydro invested $10.1 million in the WPF Segment, and projects to invest $18.6 million by the end of 2019, which would be $9.6 million above the 2015 - 2019 forecast of $9.0 million.

The overspend over 2015-2019 forecast is largely driven by the unpredictable nature of feeder outages, and the increase in the number of assets requiring intervention to meet the revised objectives of the segment in response to reliability and resiliency needs of Toronto Hydro's large customers, as explained below.

In 2015, the utility introduced FESI-6 metric specifically for feeders that serve large Commercial & Industrial class customers across the system. This improvement aligns with customer priorities – i.e. larger customers consider system reliability as a top priority. The work completed under the WPF segment from 2015 to 2017 included the replacement of deteriorated or damaged underground cable segments, poles in poor condition, cracked or chipped insulators, flashed over transformers, switches and metal brackets, lighting arrestors, etc. The contribution of the WPF segment to the reliability of the distribution system is evident based on the reduction in the number of FESIs and in their customer impact measured by CI and CHI, as previously shown in Figure 8.

The total number of customers interrupted due to FESI-7 feeders decreased from over 300,000 in 2013 to less than 150,000 in 2017, as shown in Figure 12.

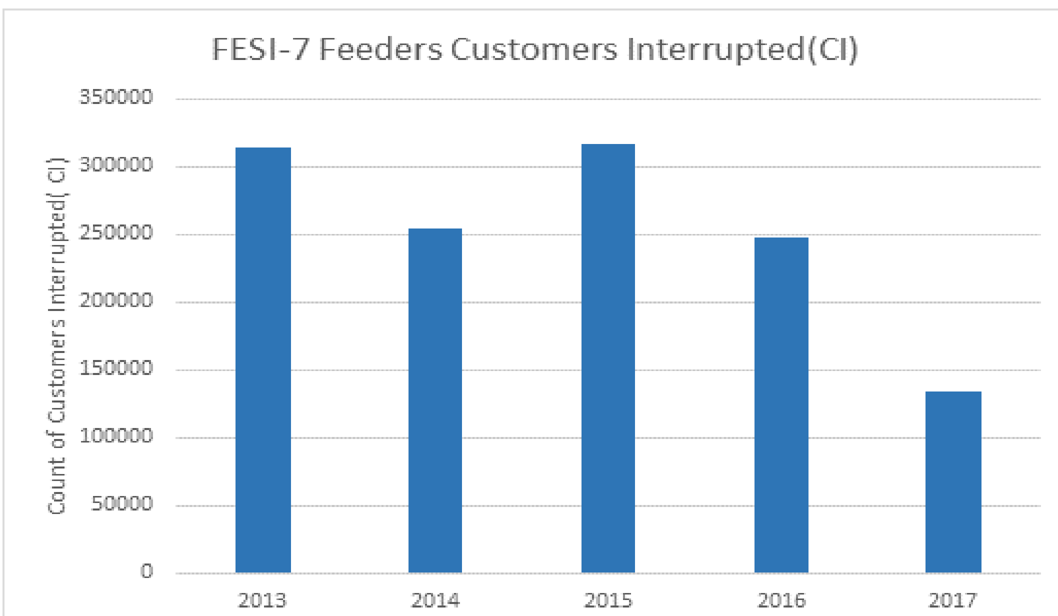


Figure 12: Total Customers Interrupted From FESI-7 Feeders

Toronto Hydro plans to maintain the current levels of performance, and has based its 2020-2024 forecast expenditure and volume for the WPF segment largely on historical trends. This forecast however also accounts for the Program moving into more challenging and expensive underground work which involves civil construction or other asset replacement. In the past, the majority of the work in the segment was focussed on replacing overhead assets such as pole-top transformers, insulators, and switches. The yearly forecasted expenditure is maintained at an average of $5.0 million for a total spend of $24.9 million over this plan period.

WPF scopes are prioritized based on the reliability performance of each feeder and field patrol findings. The intent of the short term capital work is to mitigate immediate risk to reliability by replacing or upgrading assets that are at high risk of failure that will result in power outages. Most of this work is targeted for completion within a 12 month period so the outcome of reliability improvement is realized immediately thereafter.

E6.7.5 Options Analysis

E6.7.5.1 Reactive Capital Segment

Toronto Hydro considered two alternatives for addressing failed or failing assets:

1) Performing reduced reactive capital work, or
2) Performing the Reactive capital as proposed in this Program.

1. Option 1: Reduced Reactive Capital Work

This option entails a reduction in budget to address reactive capital work during the 2020-2024 CIR period. Implementing this option would result in inadequate funding to meet the demands of required reactive capital work as forecasted based on historical trends. A backlog of work would arise and deprive planned capital or maintenance programs of required resources. Addressing reactive capital work through planned capital rebuilds would also take time to plan, design and execute and do not typically allow for the timely replacement of failed and failing assets. Inadequate funding would also increase environmental risk, and safety risks to the public and Toronto Hydro employees. Ultimately this would lead to more interruptions and longer outages for customers, potentially significant legal consequences (e.g. related to environmental obligations), and risk of worker and public safety incidents.

2. Option 2 (Selected Option): Proposed 2020-2024 Reactive work

Option 2 is the preferred alternative as it accounts for adequate capital funding to effectively replace and repair failed or failing assets over the 2020-2024 planning horizon. The proposed expenditure is necessary to maintain system performance and reliability, ensure customer satisfaction, eliminate safety risks to the public and Toronto Hydro employees, and mitigate environmental risks.

E6.7.5.2 Worst Performing Feeder Segment

Toronto Hydro considered two alternatives for addressing WPFs:

1) Planned capital rebuild; and
2) Continuation of the current WPF segment (preferred option).

3. Option 1: Planned Capital Rebuild

Addressing WPFs through planned capital rebuilds is the optimal long-term solution. However, rebuild projects take time to plan, design and execute, and do not typically allow for the timely mitigation of worsening reliability trends on poor performing feeders. Without targeted, short-term interventions on poor performing feeders, customers would likely continue to experience a high frequency of sustained interruptions. Further, the number of WPFs would most likely increase, thus negatively impacting SAIFI and SAIDI along with customer satisfaction levels over time. Accordingly, pursuing long-term capital rebuilds without a complementary WPF segment is not recommended.

4. Option 2 (Selected Option): Continue WPF segment

The status-quo and preferred option is to continue the mitigation work under the WPF segment at the pace that has demonstrated results and successes during recent years (i.e. 2015-2017). This option would provide immediate reliability improvements to customers served by poor performing feeders at a reasonable cost, and serves as a “bridge” solution until planned capital rebuilds can be executed.

E6.7.6 Execution Risks & Mitigation

E6.7.6.1 Reactive Capital Segment

Work under the Reactive Capital segment is not pre-planned or scheduled. All asset replacements are made in response to either an asset failure or deficiencies indicating high-risk assets that require immediate replacement and cannot be addressed during planned capital replacement.

Reactive capital work volume can be triggered by activities from Toronto Hydro’s maintenance programs, day-to-day operations, or emergency response. Failed or failing assets are prioritized for replacements based on engineering assessments of the deficiencies and the potential impact to reliability, safety and the environment. Before reactive capital work can be executed, Toronto Hydro must consider the timing, scheduling, and approval of the work, as well as the asset type, its location and the nature of the failure. Once the failed asset is located, crews are dispatched to the site to perform the replacement. Due to the unpredictable nature of reactively replacing assets, the costs to execute such work can fluctuate.

Depending on the type of asset and the nature and scope of an asset failure, there are various risks that can delay the completion of reactive work such as resource and logistics constraints, and major storm events. In addition, depending on the location and nature of an asset failure, additional design, planning, and approval may be required before the work can be executed. Also, feeders may not be available to be taken out of service to perform the necessary replacements or rebuilds.

Depending on the nature, severity and location of an asset that has failed, coordination with third parties (contractors) may be employed to ensure replacement work can be performed in an efficient and safe manner. Feeders are strategically planned to be taken out in order to maximize the number of asset replacements.

E6.7.6.2 Worst Performing Feeder Segment

Similar to the reactive capital segment, the WPF segment is highly dynamic compared to other, typical planned work programs. Feeder and project prioritization can change quickly and often depend on emerging feeder conditions in the field. Delay in timely intervention may result in additional outages.

To mitigate the risk of project execution, Toronto Hydro has mapped out the WPF process, where feeder patrols scheduling and timelines for project execution have been clearly established. As a result, mitigation work is normally placed on high priority and scheduled for field execution taking into consideration available resources. Emphasis is placed on feeders that have experienced a high number of outages in a 12-month rolling window.

Feeder scheduling/restriction and road work moratoriums may also pose risks to the completion of work in a timely manner. To mitigate risks that might impede timely completion of work under this Program, bi-weekly stakeholder meetings are scheduled to review status of work, emerging issues, as well as alternatives to ensure work is completed in a satisfactory manner and time frame.

E7 System Service Investments

E7.1 System Enhancements

E7.2 Energy Storage Systems

E7.3 Network Condition Monitoring and Control

E7.4 Stations Expansion

E7.1 System Enhancements

E7.1.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 45.5	**2020-2024 Cost ($M):** 27.7
Segments: Contingency Enhancement, Customer-Owned Substation Protection	
Trigger Driver: Reliability	
Outcomes: Reliability, Safety	

The System Enhancements program (the "Program") involves modifying of Toronto Hydro's existing distribution system to strategically address critical issues, including operational constraints, protection enhancement opportunities, security-of-supply risks, and system operational inefficiencies. Both segments of work in this Program, discussed below, are continuations of activities included in Toronto Hydro's 2015-2019 Distribution System Plan ("DSP"). The 2020-2024 proposals are intended to support the utility's objective of maintaining current levels of reliability while improving system resiliency in the face of increasingly frequent adverse weather events.

The System Enhancements program consists of the following two segments:

- **Contingency Enhancement:** This segment is designed to enhance Toronto Hydro's ability to efficiently restore power to customers in the Horseshoe area by: (1) adding remotely operable feeder tie and sectionalizing points on feeders where the number of switching points is currently sub-optimal or where there is an opportunity to facilitate or expand a feeder automation network, (2) upgrading undersized conductors on lateral loops, and (3) upgrading undersized trunk egress cables. Toronto Hydro plans to invest an estimated $24.9 million in 2020-2024 in Contingency Enhancement, which is a 44 percent reduction in segment spending relative to the forecast total for the 2015-2019 period. The reduced pace is influenced by recent improvements in reliability on the overhead system (see Exhibit 2B Section E6.5).
- **Customer-Owned Substation Protection ("COSP"):** This segment is a continuation of Toronto Hydro's plan to install fused protection devices upstream of customer-owned equipment to rectify inadequate protection. In total, Toronto Hydro plans to install protection upstream from approximately 310 customer-owned substations for an estimated total cost of $2.8 million in the 2020-2024 period. This pace of investment will support

Toronto Hydro's objective of maintaining reliability in the Horseshoe over the 2020-2024 period.

Overall, Toronto Hydro plans to spend an estimated $27.7 million in this Program over the 2020-2024 period.

E7.1.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Reducing fault isolation times on targeted feeder trunks by approximately one hour on average through Supervisory Control and Data Acquisition ("SCADA") switches; ○ Reducing the average duration of outages by for targeted feeders by installing SCADA-enabled tie and sectionalizing points; ○ Reducing outages resulting from contingencies by upgrading undersized or de-rated equipment; and ○ Reducing the impact of customer-owned substation equipment failures on the overhead system by installing approximately 930 protection devices.
Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency (TRIF) measure and safety objectives by installing remote switching, which reduces crew exposure to the safety risks associated with manual switching.

E7.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Reliability
Secondary Driver(s)	Safety, Operational Constraints, System Efficiency

Toronto Hydro's System Enhancements program is necessary to support the utility's system reliability objectives for 2020-2024. Across the system, Toronto Hydro has identified opportunities to maintain and improve reliability outcomes, including system resiliency, by implementing targeted system modifications. These system design interventions can cost-effectively reduce the consequences of failure (i.e. the number of customers affected and outage duration), as distinguished from the probability of failure, which is typically addressed by replacing or maintaining aging and poor condition assets. The investments in this Program are intended to reduce the consequence of failures by improving power restoration capabilities during both normal interruption events and adverse weather events, which are becoming increasingly frequent.

Both segments in this Program achieve their objectives by optimizing sections of the distribution system that are not configured or equipped to respond effectively to contingency situations.

E7.1.3.1 Contingency Enhancement

Over the past several years, through customer calls, emails, community meetings and councillor meetings, customers and stakeholders have encouraged Toronto Hydro to find ways to reduce outage frequency and durations on the overhead system. The investments in the Contingency Enhancement segment respond to these concerns by helping to enhance Toronto Hydro's ability to restore power quickly when outages occur in the Horseshoe area of the City, including during high impact contingency events such as major storms.

The Contingency Enhancement segment includes the following four project types, all of which are continuations of activities included in Toronto Hydro's 2015-2019 DSP:

1) installing additional SCADA-enabled tie and sectionalizing points;
2) establishing and expanding feeder automation[1] networks;
3) upgrading under-sized loop conductors; and
4) upgrading the capacity of trunk egress cables.

Each of these activities is discussed in the following sections.

1. Tie and Sectionalizing Points

When a feeder or a section of feeder loses power during a contingency event, customers connected to the failed feeder or section should receive power from an alternate feeder via feeder tie points

[1] Feeder Automation was a stand-alone program in Toronto Hydro's 2015-2019 DSP. Toronto Hydro has grouped Feeder Automation with Contingency Enhancement going forward. This reflects the utility's change in approach to Feeder Automation, discussed in section 3.1.2 below.

and sectionalizing switches. However, if a feeder is not sufficiently equipped with sectionalizing or tie points that can divide the load into smaller sections, re-routing service may not be possible for all customers. This is especially true during peak loading times. Load growth and the addition of new developments can exacerbate this problem. The Contingency Enhancement segment adds tie or sectionalizing points to those feeders lacking sufficient switches.

A secondary issue is the lack of remote operation at some existing tie-points. Before SCADA-controlled devices were available, manual switches were installed. To restore power with manual switches, employees must travel to perform the switching work on-site. Depending on the location of the fault and accessibility of the switches, this typically takes one to two hours. In contrast, SCADA-controlled switches will relay instant loading information to the control room, enabling controllers to remotely re-route power to adjacent feeders within minutes. Remotely controlled switches are also safer than manual switches because employees are not exposed to live equipment during manual switching operations.

To provide appropriate backup supply, Toronto Hydro's standard design practice is that feeders should have at least three strategically located tie points connected to three unique back up feeders as follows:

1) The first tie point connects to another feeder from the same substation bus;
2) The second tie point connects to another feeder on a separate bus located at the same substation; and
3) The third tie point connects to another feeder from a different substation.

This arrangement ensures a contingency power source is available for the faulted feeder regardless of whether the fault occurs at the feeder, bus, or station level. The current average duration for outages on feeders with less than three tie-points is 260 minutes per year per feeder. Upon the completion of this segment, Toronto Hydro estimates this would reduce to 209 minutes per year per feeder, resulting in an approximately 20 percent reduction.

Figure 1 below shows a map of Toronto highlighting those feeders that have less than three feeder ties.

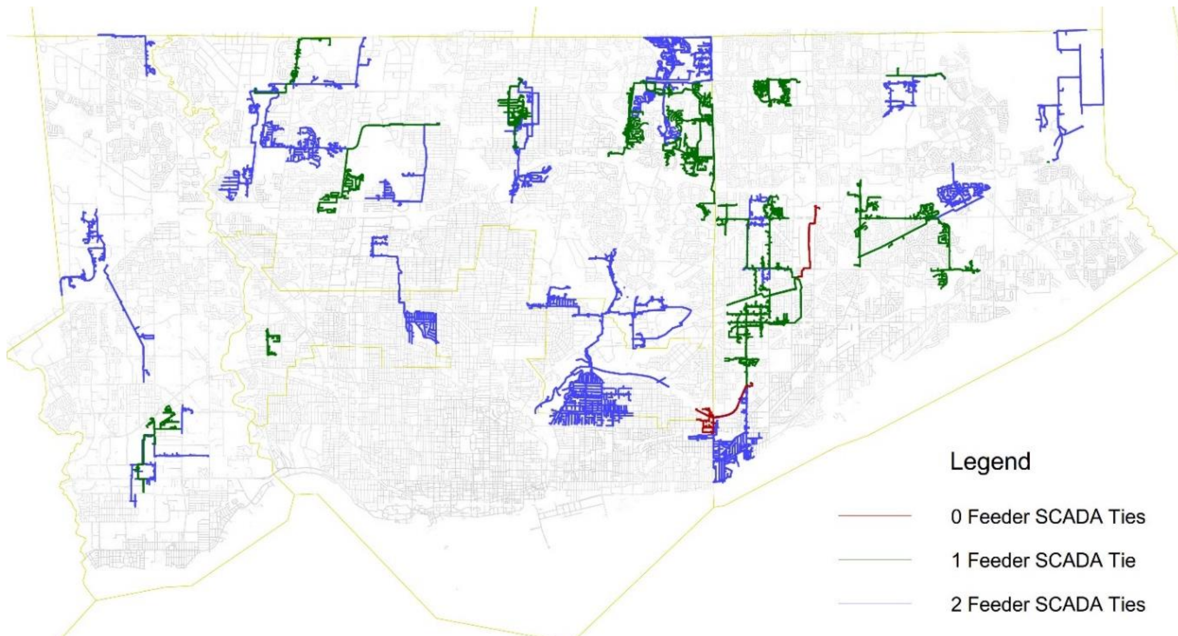


Figure 1: Map of Toronto showing Feeders with less than 3 Tie Points

2. Feeder Automation

Feeder Automation projects replace existing manually operated switches on the main sections of a feeder (i.e. the feeder "trunk") with remotely operable SCADA switches. Automation can then be added to create a network of switches that work together, without manual intervention, to rapidly isolate a fault and minimize the number of customers affected. Feeder Automation is an extension of the tie and sectionalizing point work described above as they both involve the installation of SCADA-enabled switches on feeders. However, while the latter targets feeders with insufficient tie and sectionalizing points, Feeder Automation focuses on strategically installing sufficient SCADA switches on feeder trunks in targeted areas in a way that would enable the eventual creation of a network of automated switches.

Feeder automation has two main components: SCADA switches, and a Fault Location Isolation and Service Restoration application ("FLISR").

1) SCADA switches on feeders allow the remote troubleshooting and sectionalization of feeder faults to achieve more efficient and rapid troubleshooting and restoration, which is the focus of the Feeder Automation work within the Contingency Enhancement segment.

2) FLISR is an application which, together with the Network Management System ("NMS"), can automatically read and process signals from the distribution system to locate a fault. The implementation of Feeder Automation using FLISR would enable Toronto Hydro to rely on autonomous detection and isolation of affected portions of the feeders, further reducing fault isolation time.

During a feeder level outage, control room operators and crews first work to locate the fault and sectionalize the feeder to isolate the faulted section. This will minimize the impact of the outage to a large portion of the customers before crews are able to identify the root cause of the outage and complete repairs. The use of remote operated SCADA switches reduces the fault isolation time by approximately one hour on average. The use of FLISR would further reduce the fault isolation duration to within minutes, which allows crews to focus on the root cause of the outage and reduces the needs for additional troubleshooting and switching crews. It also allows faster restoration of power to all the remaining customers.

Toronto Hydro is focusing on the trunk feeders on the 27.6 kV distribution network in the Horseshoe area as they have the largest impact on customers. As shown by Figure 2, the 27.6 kV system accounts for the largest share of reliability issues in the system, which also means considerable resources are required to restore outages using manual or remote-operated SCADA switches. Trunk outages interrupt the entire feeder and can impact hundreds to thousands of customers. In contrast, lateral or local outages only impact up to a few hundred customers.

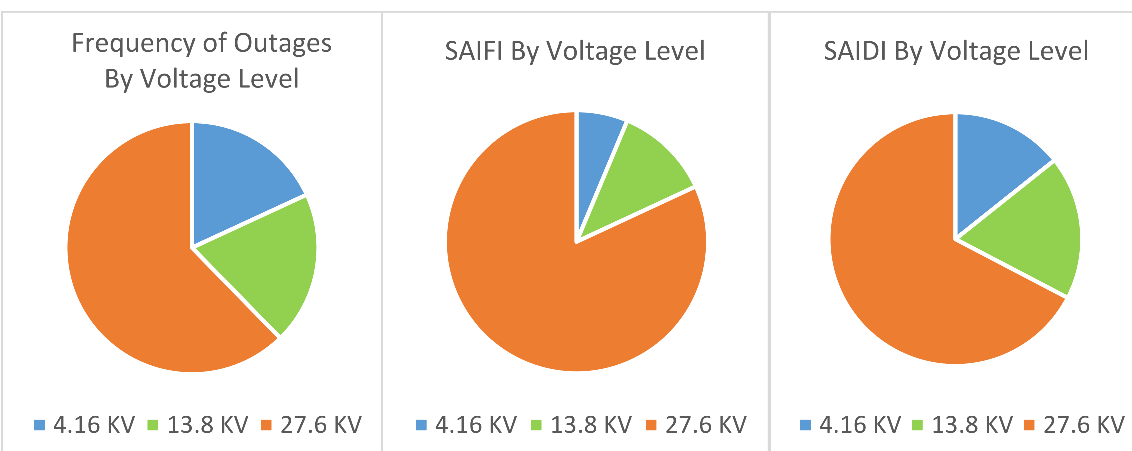


Figure 2: Reliability Impact by Voltage Level

Even though trunk outages make up only a third of the outages that occur on 27.6 kV feeders, they can significantly impact SAIFI and SAIDI (as shown in Figure 3 below). The installation of SCADA switches will allow faster sectionalization and restoration of customers in unaffected sections, thereby reducing the impact of trunk outages and improving the reliability of the system.

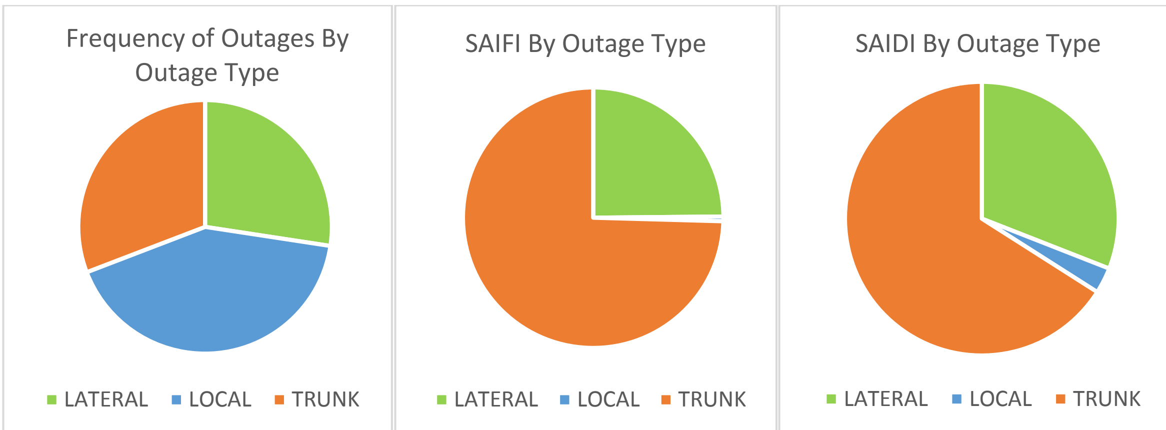


Figure 3: Reliability Impact by Outage Type

As of the end of 2017, 48 feeders are considered to be automation ready (defined as having at least three SCADA sectionalizing switches, and at least two SCADA tie points). The switches on these feeders are ready for the implementation of feeder automation to realize the full benefits of autonomous restoration. Approximately 149 feeders are considered to be partially automated (defined as having at least 1 SCADA sectionalizing switch), and the remainder of the over 60 feeders are without any SCADA switches at all. For these feeders, additional switch installations are required to provide remote restoration capabilities and enable automation to allow for faster outage restorations to customers.

3. Undersized Loop Conductor

Figure 4 depicts a typical looped distribution lateral supplying a series of transformers off the main trunk portion of a feeder. There is an open point near the middle of the loop so that, under normal operating conditions, about half of the load in the loop is supplied from one lateral or the other.

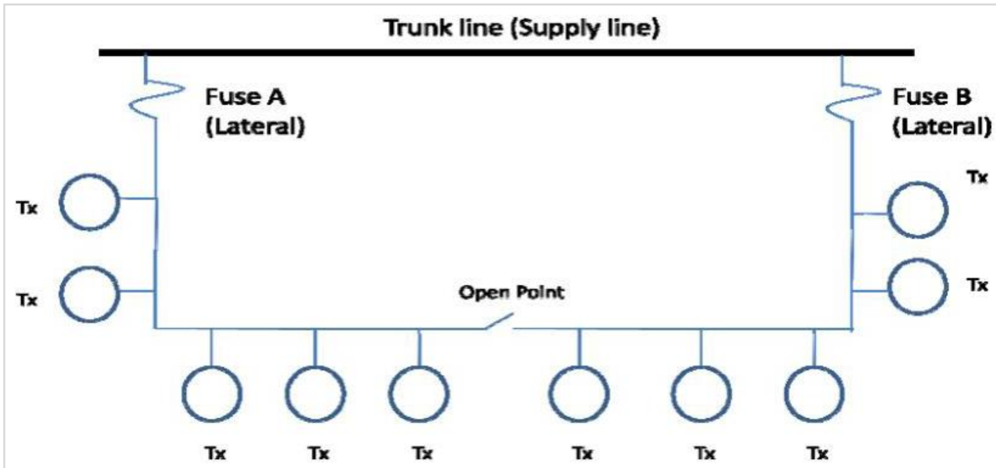


Figure 4: Looped Distribution Design

The conductor on either lateral is designed to be large enough to handle the load of the entire loop if necessary. In a situation where a fault occurs on the first section downstream of Fuse B, the load must be supplied entirely from the other side of the loop, as shown in Figure 5.

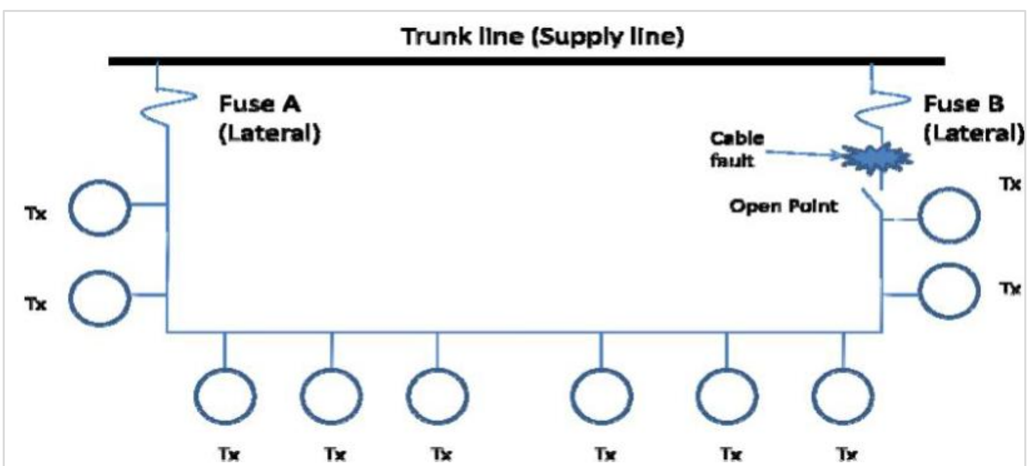


Figure 5: Power restoration in loop after a fault has occurred

Gradual increases in load in certain areas have resulted in existing conductors no longer being able to supply the load of the entire loop. A contingency situation in these locations would cause cascading power outages to the entire loop. Controllers monitor the conductor size and number of transformers transferred to the circuit under contingency; however, the actual load on each transformer may not be known by the controller in real-time. Therefore, if a conductor has previously withstood a high current during repair work without failing, its integrity may have already been compromised, which could lead to premature failure of the loop conductor requiring reactive repair work.

Toronto Hydro plans to upgrade undersized conductor in lateral loops to ensure that they are rated to carry the load of the entire loop under contingency conditions. Figure 6 shows the locations of undersized loop conductors in Toronto.

Figure 6: Map of Toronto showing undersized loop conductors

4. Insufficient Capacity of Trunk Egress Cable

Toronto Hydro plans to replace existing aluminum cable on feeder trunk egress sections with copper cable. The initial section of a feeder, between the station breaker and the first distribution switch (i.e. the section upstream from any load connections), is called the “egress”. The egress cable must be adequately sized to supply the load of the feeder, plus any additional load from adjacent feeders under contingency, up to the maximum capacity of the feeder breaker (i.e. 600 A).

Some egress cable installed in the 1960s and 1970s on 27.6 kV feeders is 1000 kcmil aluminum, a cable type that is de-rated (i.e. its current carrying capacity is lowered) when installed in an underground environment, to 500 A in summer and 530 A in winter. In some areas, load growth has exceeded the capacity of this existing configuration. Under contingency, a feeder is required to carry the load of adjacent feeder sections that connect to it. Thus, it is critical that the maximum capacity of the feeder is utilized to restore as many customers as possible. This poses a high-risk situation, as failure of the load-carrying feeder to deliver power to its maximum capacity may result in loss of power to two other feeders, causing outages to a large area for four hours (or more) that it would take to make repairs. Due to the limitation of current carrying capability of these trunk egress cables, customers that would otherwise be served by those feeders under a contingency would experience an outage until the work on their normal feeder has been completed. For these reasons, it is critical that the egress portion of the feeder be fully rated to effectively utilize the rated capacity of the breaker.

Under a contingency condition, controllers may not be able to utilize feeders with a 1000 kcmil aluminum egress trunk cable to pick up load lost on adjacent feeders during a fault or planned maintenance. As a result, affected customers will experience prolonged power outage until the faulted asset is repaired or replaced on the normal supply feeder. Toronto Hydro may also be required to defer important scheduled maintenance work until the load on feeders is low enough to be re-routed, resulting in the deterioration of asset conditions and further reducing reliability.

There are 20 stations with a total of 103 km of egress cable considered under-rated (i.e. not 1000 kcmil copper). Table 4 shows the amount of under-rated cable for each of these stations. Toronto Hydro will target feeders with under-rated egress cable that consistently experience high loading, prioritizing them primarily based on loading levels and the reliability of adjacent feeders. These targeted upgrades and installations will better equip the distribution system to meet the needs of customers in contingency scenarios and more effectively maximize the customer value derived from existing feeders by minimizing unnecessary failure risk.

Table 4. Stations with Under-Rated Trunk Egress Cable.

Station	Under-Rated Egress Cable (km)	Total Egress Cable (Circuit km)
Bermondsey TS	24	24
Runnymede TS	1	1
Woodbridge TS	0.1	0.1

Station	Under-Rated Egress Cable (km)	Total Egress Cable (Circuit km)
Leslie TS	18	20
Agincourt TS	6	7
Fairchild TS	18	21
Bathurst TS	16	24
Horner TS	1	2
Rexdale TS	3	6
Cavanaugh TS	6	12
Ellesmere TS	1	3
Fairbanks TS	2	8
Richview TS	0	2
Finch TS	3	16
Scarborough TS	1	6
Warden TS	0.3	4
Malvern TS	0.2	4
Leaside TS	0.1	3
Sheppard TS	0.0	1
Manby TS	0.1	11
Total	**102.6**	**175**

E7.1.3.2 Customer-Owned Substation Protection (COSP)

The COSP segment is primarily designed to mitigate the reliability risks posed by customer-owned substation equipment. To prevent outages to customers upstream from customer-owned substations, Toronto Hydro must ensure that utility-owned protection devices are installed and properly coordinated as safeguards where appropriate.

While Toronto Hydro has protection devices in many places in the Horseshoe area, in some areas these devices are inadequate or absent altogether. There are currently 2,110 customer-owned substations in the Toronto Hydro network: 1,417 substations are located in the Horseshoe area (i.e. the former suburbs) and 693 are in the vicinity of downtown Toronto. During sample substations inspections in the Horseshoe area, 64 of the 185 visited substations were found to be missing upstream utility-owned protection devices. It is estimated that a total of approximately 480 substations could be missing upstream utility-owned protection devices.

There are several reasons as to why this issue and the uncertainty in the number of locations with this issue exist:

- At the time of original construction, the impact that a customer's load could have on the system may have been negligible. However, over time, a customer's load could have risen considerably. Given the increase in customers and associated loads, these substations can now have a significant impact on the reliability of power supply and cannot be neglected.
- Some substations are too large to have upstream fuses and therefore at the time of original construction, these customers would not have upstream protection set up. However, gang-operated load-break SCADA switches can be used today to connect this type of large substation to the feeder trunk as specified in Toronto Hydro's current standards.
- At the time of construction, the manufacturers might not have had the preferred protection devices available (e.g. fuse sizes were limited) for the specific customer-owned substations and loading requirements. As technology evolved, more options are now available (e.g. fuses at higher rating), which would provide better protection to the system.

Toronto Hydro plans to minimize existing and potential impacts associated with its upstream protective devices by ensuring that such devices are in-line with the utility's most recent standards. During a fault, an uncoordinated upstream protection device would fail to act after the customer-owned protection device operates and before the station breaker is triggered. If Toronto Hydro-owned protection devices are improperly configured or absent altogether, the inability for a customer-owned protection device to isolate a fault will trigger the station breakers, which would interrupt the entire feeder. According to Toronto Hydro's Interruption Tracking Information System ("ITIS"), there were 60 interruptions caused by the failure of customer-owned equipment from 2013 to 2017. Figure 7 shows the outage distribution across the City of Toronto and Figure 8 shows the number that occurred in each year.

Figure 7: Historical Reliability Events 2013-2017

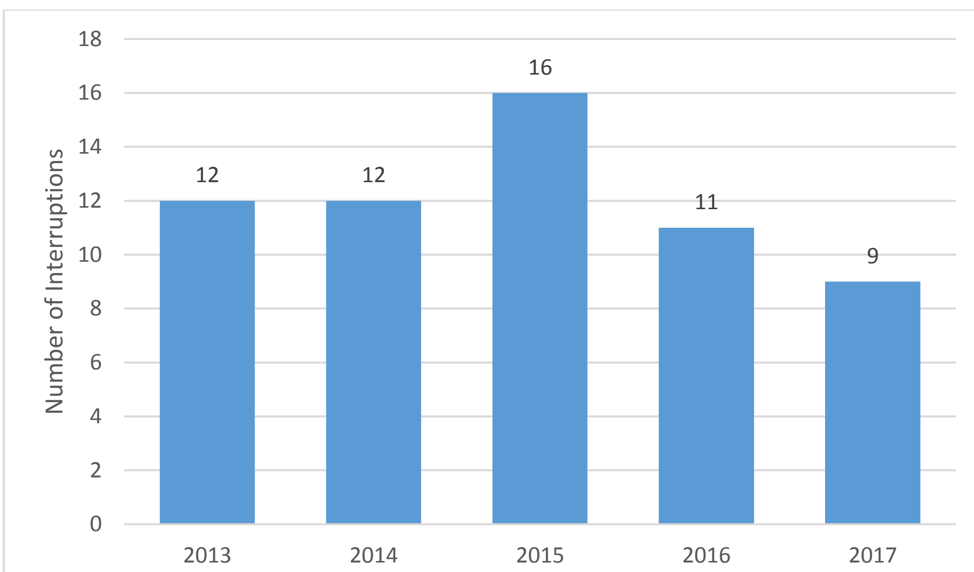


Figure 8: Interruptions due to Failure of Customer-Owned Assets

As a result of inadequate protection, these events interrupted Toronto Hydro customers. If the proper utility protection devices were in place, the impact would be limited to the faulted customer only. The COSP segment is expected to improve reliability performance in the overhead distribution system caused by customer-owned equipment failures.

E7.1.4 Expenditure Plan

Table 5: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Contingency Enhancement	6.7	15.9	12.1	3.5	6.1	5.5	5.6	5.1	4.3	4.4
Customer-Owned Station Protection	-	-	-	0.6	0.6	0.6	0.5	0.5	0.6	0.6
Total	**6.7**	**15.9**	**12.1**	**4.0**	**6.7**	**6.2**	**6.2**	**5.6**	**4.8**	**4.9**

E7.1.4.1 Contingency Enhancement

Toronto Hydro invested $34.8 million in the Contingency Enhancement segment over the 2015-2017 period and is forecast to spend an additional $9.5 million in 2018-2019, for a total of $44.3 million. This is less than what was initially proposed in Toronto Hydro's 2015-2019 Distribution System Plan. Underspending was due in part to some work that was originally considered part of Contingency Enhancement being completed under renewal program portfolios instead. Further, for the Feeder Automation work, in 2016 Toronto Hydro changed from a decentralized to a centralized automation method which lowered costs. Decentralized automation requires SCADA switch retrofits (which is not needed for centralized automation) and this reduces work and costs required for Feeder Automation.

Between 2015 and 2017, Toronto Hydro added tie points to 10 feeders, added sectionalizing points on 14 feeders, and upgraded one undersized lateral loop. In addition, Toronto Hydro upgraded end-of-life and underrated egress cables at Manby TS, Scarborough TS, Leslie TS, Bathurst TS, and Warden TS, contributing to higher segment expenditures in 2016 and 2017. In 2018 and 2019, Toronto Hydro plans to add tie points on seven distribution feeders, add sectionalizing points on three feeders, and upgrade egress cables at Bathurst TS and Fairchild TS. These investments will benefit customers by reducing the risk of outages and enabling improved restoration and operational efficiency.

For Feeder Automation between 2015 and 2017, Toronto Hydro's implementation included the automation of eight Fairchild TS feeders in the high density areas of North York, expanding on previous implementations of feeder automation in the west end of Toronto. The existing automation infrastructure and switching capabilities in this North York area is modernized with current standard SCADA switches and Remote Terminal Units ("RTUs") to provide ease of integration and a cost-effective means to implement Feeder Automation.

Toronto Hydro plans to invest approximately $24.9 million in similar Contingency Enhancement projects in the 2020-2024 period. The reduction in expenditures, relative to 2015-2019 levels is influenced by improvements in reliability performance in the Horseshoe area of Toronto and the general preference of low-volume customers for price mitigation over additional reliability enhancements.

Toronto Hydro will fund projects in the highest priority locations as determined by analyses of reliability performance, loading statistics, cost-benefit analysis, and other applicable criteria, with the overall objective of maximizing customer value and contributing efficiently to short- and long-term system reliability targets.

E7.1.4.2 Customer-Owned Substation Protection

As seen in Table 5 above, Toronto Hydro deferred capital investment in COSP until 2018. This was a new program in the 2015-2019 DSP and the utility prioritized it behind core renewal work. Toronto Hydro plans to begin investment activities in 2018.

In 2020, Toronto Hydro plans to continue installing protection devices upstream of customer owned substations. In total, Toronto Hydro plans to install 930 fused in-line switches upstream from 310 customer-owned substations for an estimated total all-in cost of $2.8 million in the 2020-2024 period. Toronto Hydro expects 60-70 locations per year to be a pace of work that can be realistically achieved and that will enable the utility to address the majority of the estimated 480 locations without proper protection by the end of 2024.

Toronto Hydro will prioritize locations based on the age and condition of customer-owned equipment, the sufficiency or insufficiency of existing protection equipment and protection coordination, historical reliability performance, and the type of distribution feeder (i.e. locations on the overhead system are given higher priority due to greater exposure to reliability risks). As noted in the Execution Risks (Section 6.2), the prioritization and pacing of this Program will depend in part on the responsiveness of customers to Toronto Hydro's information and coordination requests.

E7.1.5 Options Analysis

E7.1.5.1 Options for Contingency Enhancement

1. Option 1: No Contingency Enhancement Segment

Maintaining the status quo involves forgoing the Contingency Enhancement segment. Customers served by problematic feeders would continue to experience lengthy outages during contingency conditions. In addition, Toronto Hydro would incur higher costs with respect to reactive work to replace equipment that was damaged due to overloading and manual switching work. For these reasons, the status quo option is not recommended.

2. Option 2 (Selected Option): Contingency Enhancement

Executing the proposed Program strengthens Toronto Hydro's distribution system in contingency conditions, improving reliability for affected customers. The addition of SCADA controlled tie and sectionalizing switches would enable Toronto Hydro to segment a feeder into smaller sections, so that load could be transferred to alternate feeders to reduce the duration of power outages. Customers could expect improved service reliability and Toronto Hydro would gain efficiency advantages by extending the reach of the SCADA system and enabling Feeder Automation networks. As well, upgrading aluminum egress cables to copper would allow feeders to utilize the full rated capacity of the circuit to deliver power during a contingency condition. Although Toronto Hydro will target the highest priority locations over 2020-2024, parts of the distribution system will continue to operate sub optimally in contingency situations. However, this alternative is recommended as it strikes a balance between mitigating risks and cost over the 2020-2024 period.

3. Option 3: Contingency Enhancement at Accelerated Pace

Executing the Program at a faster pace would extend the areas and number of customers benefitting from improved reliability as described for option 2. However, this would increase costs. Mitigating costs has been identified as a high priority, above reliability, by customers in the Horseshoe area of Toronto.

E7.1.5.2 Options for Customer-Owned Substation Protection

1. Option 1: No installation of COSPs

Under the status quo, customer-owned substations with inadequate protection would continue to pose a risk of causing interruptions to other Toronto Hydro customers on the overhead system if customer-owned equipment fails. The inspection of sample substations has indicated that over 22 percent of customer-owned substations in the Horseshoe area are either aged or poorly maintained. Without regular maintenance of the customer-owned substations (which are often neglected), this equipment is increasingly more likely to fail and cause reliability (e.g. outages to upstream customers) problems on Toronto Hydro's distribution system. The failure of customer-owned equipment has already resulted in approximately 12 interruptions per year during the 2013-2017 period. Toronto Hydro expects this number to increase in the near future if the proposed plan is not implemented. For these reasons, Toronto Hydro does not recommend this option.

2. Option 2 (Selected Option): Customer-Owned Substation Protection

By undertaking the COSP segment at the proposed pace, Toronto Hydro expects to improve reliability on the overhead system. Installing utility-owned protection devices will enable Toronto Hydro to isolate faults at customer-owned substations. This will minimize the likelihood that an entire feeder would be affected by a fault at a customer-owned substation, thus reducing the number of customers that will experience power outages. At the proposed pace, Toronto Hydro expects to address the majority of the locations without proper protection by the end of 2024. However, until all the required protection devices are installed, the risk of customer-owned equipment failures causing interruptions to other customers on the overhead system will continue. Nevertheless, this option is the recommended option as it balances risk mitigation and costs.

3. Option 3: COSP at Accelerated Pace

By accelerating the rate at which protection devices are installed, Toronto Hydro would mitigate the impact of faults occurring at customer-owned substations sooner. However, this would come at a higher costs, and in any event a faster pace may not be feasible from a resourcing and execution perspective. Full information on the number of locations and specific work required at each location will not be available until the audits and engineering analysis that are ongoing as of 2018, are fully completed.

E7.1.6 Execution Risks & Mitigation

E7.1.6.1 Contingency Enhancement

Unforeseen site conditions, such as the presence of third party infrastructure (e.g. gas, sewer or water pipes), can necessitate scope changes, and result in cost increases or delays in the completion of the underground work. In these situations, Toronto Hydro will reprioritize or reschedule work after taking all factors into consideration.

As well, Toronto Hydro must take into account city road moratoriums that may be imposed after the scope of work is issued, which could result in delays. However, Toronto Hydro will mitigate this risk by ensuring that it maintains open communication with the City of Toronto and coordinates its activities with those of the city.

Feeder Automation projects, by their nature, require robust communication between switches. Under the decentralized approach to automation, communication between switches created risk for fully implementing automation schemes. Under the proposed centralized approach (FLISR) utilizing the NMS, this risk is expected to be mitigated.

E7.1.6.2 Customer-Owned Substation Protection

One of the main risks of the COSP segment is related to the ongoing assessments and that fact that all substations have yet to be fully audited. The costs associated with the installation of new or replacement protective devices will differ depending on the exact number of stations that require new or replacement protective devices. For example, some locations may already have a switch in place but may be missing a fuse. In this case, as long as the condition of the currently installed equipment is adequate, Toronto Hydro will only install a fuse. The proposed plan is based on information that is available as of 2018 and will be adjusted based on new information that becomes available.

Acquiring all necessary data and documentation is another risk associated with this segment. Some equipment data is not readily available to Toronto Hydro because it is associated with customer-owned substations (e.g. primary protective devices or damaged transformer nameplate). In these instances, Toronto Hydro will need to contact the asset owner to obtain the required information. Since Toronto Hydro has no control over the customer's response time, this process may result in delays. However, Toronto Hydro will reach out to relevant customers on a timely basis and follow-up with the customer periodically for the requested information to minimize this risk.

An outage may be required in order to complete the protection upgrades. Scheduling outages with the customers may be a challenge requiring active management. While Toronto Hydro has no control over the customer’s willingness to schedule an outage, it will consult and work closely with affected customers to reach a mutually agreed solution.

E7.2 Energy Storage Systems

E7.2.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): $0.5 (Rate Base)	**2020-2024 Cost ($M):** $5.8 (Rate Base)
2015-2019 Cost ($M): $7.9 (Net Costs)	**2020-2024 Cost ($M):** $10.5 (Net Costs)
2015-2019 Cost ($M): $35.2 (Gross Costs)	**2020-2024 Cost ($M):** $52.8 (Gross Costs)
Segments: System Service	
Trigger Driver: Category 1- Power Quality; Category 2- Public Policy	
Outcomes: Customer Service, Reliability, Financial Sustainability, Public Policy	

The Energy Storage Systems ("ESS") program was developed to put batteries to use for the benefit of customers where this non-wires option is the best solution to enable or improve distribution service. As is stated in the 2017 Long-Term Energy Plan, "Energy storage can offer benefits throughout the grid, from large-scale facilities that can reduce the need to build new supply, import electricity or use GHG-emitting generation sources, to smaller-scale devices that can provide backup services to buildings."[1]

The Long-Term Energy Plan makes reference to two studies on energy storage that were completed at the request of the Ministry of Energy: (i) a 2016 IESO study on energy storage; and (ii) a 2017 study published by Essex Energy Corporation.

The IESO study, "IESO Report: Energy Storage," was produced in response to a request from the Ministry of Energy in April 2015. This study presents the many benefits of energy storage to the bulk electricity system. Among the benefits the report identifies is the deferral of system upgrades through the use of energy storage to reduce local system peaks.[2] The report states:

> *"Energy storage could also help improve the utilization of existing transmission and distribution assets by deferring some costs associated with their upgrades or refurbishments, as well as improve the quality of electricity supply in certain areas of the system by controlling local voltages."*[3]

[1] 2017 Long-Term Energy Plan, Ministry of Energy, 2017, p.60
[2] IESO Report: Energy Storage, Independent Electricty System Operator, 2016, p.5
[3] IESO Report: Energy Storage, Independent Electricty System Operator, 2016, p.35

Essex Energy Corporation's 2017 study, "The Study of Energy Storage in Ontario's Distribution Systems," was requested by the Ministry of Energy in March 2016. The report describes a number of benefits of energy storage, including distribution system upgrade avoidance, new generation capacity avoidance, redundant power supply (reliability), and power quality improvement.[4] In one of its case studies, the report also identifies the enablement of renewable generation as another benefit of energy storage.[5]

The IESO's 2015 "Central Toronto Area Integrated Regional Resource Plan" also highlights the benefits of energy storage, particularly as a solution to "community level" energy planning, including opportunities to enable renewable generation.[6]

Battery-based Energy Storage Systems are typically comprised of two components: batteries and power electronics. Batteries absorb and supply energy in direct current ("DC"). Power electronics convert battery DC power to alternating current ("AC") (and vice versa) to enable connection to the distribution system. The power electronics also connect and disconnect the batteries from the distribution system. The ability of the ESS to deliver the expected benefits depends not only on the size of the batteries, but also on the capacity ratings, configuration, and switching capabilities of the associated power electronics.

Toronto Hydro's proposed ESS Program includes three investment segments:

1) Grid Performance ESS,
2) Renewable Enabling ESS, and
3) Customer-Specific ESS

Grid Performance ESS projects utilize battery energy storage as integrated components of the traditional distribution system. These projects benefit multiple customers, in the same way as other distribution infrastructure (e.g. poles, wires, and transformers), and can provide specific solutions to distribution problems. Toronto Hydro proposes to use ESS to achieved grid performance enhancements, including to remediate power quality problems (e.g. voltage sags), improve reliability by reducing the number or duration of outages, and increase capacity of a feeder at peak periods. During the 2020-2024 period, $5.5 million is proposed for this category of investment.

[4] The Study of Energy Storage in Ontario's Distribution Systems, Essex Energy Corporation, 2017, p12
[5] The Study of Energy Storage in Ontario's Distribution Systems, Essex Energy Corporation, 2017, p27
[6] Central Toronto Area Integrated Regional Resource Plan, Independent Electricity System Operatior, 2015, p90

ESS systems can provide other distribution benefits including local demand response (DR). A local DR solution is being implemented at Cecil TS in the 2015-2019 rate period and is proposed for expansion during the 2020-2024 rate period as described in Section E7.4.

Toronto Hydro is proposing to use ESS connected to the distribution system along the feeder segments where customers would benefit from enhanced grid performance. These needs are diagnosed on a feeder-by-feeder basis having regard to the performance of that part of the grid with respect to capacity, reliability, power quality, and other relevant measures. Where a traditional poles and wires approach is applicable, the solution might be to upgrade the feeder, re-orient feeders, install additional protection and control devices, or undertake other conventional investments. In other instances, a poles and wires option may not be available for a variety of technical or economic reasons. This program will enable Toronto Hydro to pursue ESS options, as may be optimal in a given situation.

A typical example of where a battery solution can be used to cost-effectively improve grid performance would be an area with a relatively high concentration of customers who are sensitive to power quality disturbances. Benefits of such a solution include the following:

- **Voltage Sags:** ESS can offset significant voltage sags and provide ride-through capability.
- **Voltage Support:** ESS can dynamically counteract voltage fluctuations through voltage regulation, thereby minimizing the voltage fluctuations that adversely affect customer equipment and processes.
- **Phase balancing/efficiency**: ESS can help rebalance feeders that exceed the threshold for single phase imbalances, thus decreasing the return current on the neutral conductor and reducing line losses.
- **Reliability and power quality improvements**: ESS can improve the overall power quality for customers by counteracting variations in voltage and harmonics, as well as the effects of switching.

Renewable Enabling ESS investments are distribution investments that support the growth of distributed renewable generation on the system, that in turn offset generation and transmission investments to the benefit of all Ontario rate payers, and that also create environmental benefits. Distributed renewable generation has been supported in Ontario for over a decade through a series of programs offered through the Ontario Power Authority and IESO, including FIT, microFIT, and Net Metering. Customers who do not have contracts through these programs also install renewable generation. Those customers can receive payments according to hourly market prices or, more often, offset their monthly bill by generating their own electricity behind the meter.

As is the case with other renewable enabling improvements ("REI"), projects in this investment segment are funded 6 percent in the LDC rate base and 94 percent through the provincial REI revenue stream. Over the 2020-2024 period, $5 million is proposed for this segment, with $0.3 million (6 percent) allocated to Toronto Hydro's rate base. These investments are expected to enable the aggregate connection of 5 MW of renewable projects, which would otherwise not be possible due to technical limitations of the grid.

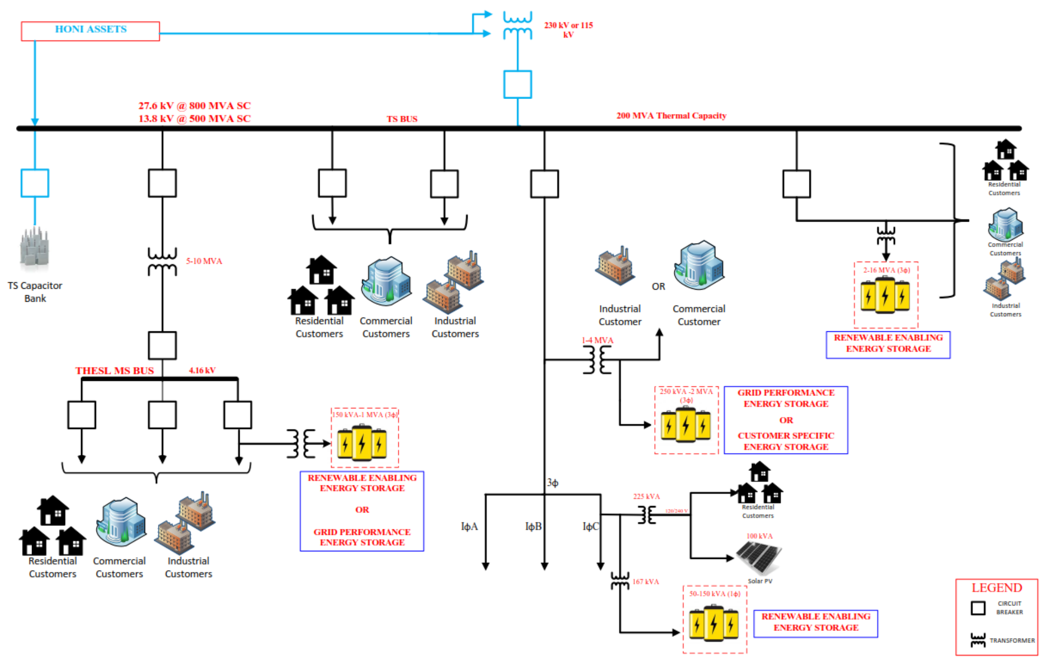
Similarly, ESS can cost-effectively enable electric vehicles ("EVs") to connect to the distribution system by addressing localized system constraints. Toronto Hydro is not proposing any EV ESS projects at this time.

Customer-Specific ESS projects would be installed at the request of the customer, typically behind the customer meter in order to maximize the benefits of the investment. These projects improve traditional distribution service outcomes such as power quality and reliability. By locating these distribution assets behind the meter, they also provide the customer with financial benefits, such as hourly peak-shaving and Industrial Conservation Initiative ("ICI") benefits (i.e. Global Adjustment relief for Class A customers who reduce their demand during provincial peak periods). Thus, the customer-specific behind the meter benefits "stack on top" of the distribution benefits, thereby creating a greater set of benefits associated with the ESS project.

Over the 2020-2024 period, $42.3 million is proposed for this segment. Investments in this segment are driven by the requesting customer's needs. In accordance with the "beneficiary pays" principle, Toronto Hydro will therefore hold these host site customers directly responsible for the costs of the projects that benefit them. As with other capital contributions, payments from the host site customers will offset the amounts that are added to rate base and charged through rates to all ratepayers. Presumptively, the result is that 100 percent of the $42.3 million of planned expenditures are offset by planned capital contributions, such that the net effect of this segment to the Toronto Hydro rate base is $0.

An example of this type of a Customer-Specific ESS project is the Metrolinx Eglinton Crosstown LRT ESS currently underway in 2018/2019. At its request, Metrolinx will receive reliability and emergency services in the event that distribution service from feeders becomes unavailable. The costs of the project are fully allocated to Metrolinx and recoverable through a capital contribution.

1 The general interconnection schematic for various ESS projects are illustrated in Figure 1 below.



2 **Figure 1: Typical Interconnection for ESS**

3 E7.2.2 Grid Performance ESS

4 E7.2.2.1 Outcomes and Measures

5 **Table 2: Outcomes & Measures Summary**

Customer Service	• Contributes to the reduction of power outages and risk of costly asset failures by mitigating the effects of upstream line disturbances.
Reliability	• Contributes to increased reliability and power quality by mitigating the effects of voltage sags including customer interruptions • Contributes to reliable system performance by enabling dynamic voltage support and reduced harmonics through line voltage regulation.

Financial	• Contributes to Toronto Hydro's financial performance and objectives by: ○ Achieving local, targeted feeder performance improvements to defer the need for conventional infrastructure upgrades. ○ Enabling phase balancing to minimize neutral return currents and improve system efficiency.
Public Policy	• Contribute to Toronto Hydro's public policy objectives by: ○ Creating the stacked benefits of utility battery storage projects that were recognized in the 2017 Long-Term Energy Plan. ○ Reducing greenhouse gas ("GHG") emissions by enabling the proliferation of energy storage, Distributed Energy Resources ("DERs"), and grid-modernization. ○ More effectively utilizing surplus off-peak power, thereby optimizing distribution and infrastructure costs.

E7.2.2.2 Drivers and Need

Table 3: Program Drivers – Grid Performance ESS

Trigger Driver	Reliability
Secondary Driver(s)	System Efficiency

E7.2.2.3 Reliability

Grid Performance ESS can eliminate voltage fluctuations and momentary interruptions, providing ride-through capability for customers and improving reliability of the grid. Grid Performance ESS can also provide the following benefits:

- Supply a feeder segment during an outage, reducing outage impact, improving SAIDI, and making the grid more resilient;
- Reduce peak demand on a feeder, thereby avoiding or deferring feeder or capacity upgrades; and
- Enable renewable generation.

The distribution system must be managed to balance supply and demand and ensure reliability for customers. "Reliability" is often viewed and measured through the lens of traditional factors such as peak capacity, outage avoidance, outage restoration, and grid resilience, which are priority outcomes particularly for customers averse to supply interruptions. At the same time, many customers on the modern distribution system not only value service continuity but also expect reliable supply in terms of high quality power that meets the operational needs of their voltage-sensitive equipment and processes. In this context, and due to an increasingly complex network of distribution assets and loads (including a growing population of DERs), utilities are increasingly having to manage bi-directional power flow, voltage regulation and power quality in addition to traditional reliability factors.

Poor power quality, most easily understood as lights flickering due to voltage fluctuations, can cause interruptions to customer owned equipment. Increasingly, critical customers (advanced manufacturing, information technology service providers, research institutions, hospitals, etc.) are installing sophisticated sensitive electronic equipment, including digital sensing and control equipment that cannot tolerate voltage dips, spikes and harmonics on Toronto Hydro's distribution system. Line disturbances and voltage fluctuations can originate from a number of sources, including traditional loads, switching devices used in the transmission and distribution systems, renewable generation and other distributed generation systems. As their operations evolve, customers, particularly those with loads over 1 MW, are demanding that the performance of the distribution grid keep up with their requirements. This means ensuring sufficient capacity and ride-through functionality to avoid outages and momentary events, regulate voltage within desired operating ranges and address transients generally caused by upstream transmission and distribution equipment. The reliability concerns of customers related to these types of disturbances can be mitigated with ESS.

As part of Toronto Hydro's customer engagement process, key account customers were asked a series of questions and to rank their priorities. Key account customers ranked reliable electrical service as their top priority. Further, in response to this open-ended question, "Is there anything else Toronto Hydro can do?", 13 percent of respondents cited improvements to power quality in their answers. Figure 2 below is a summary of their responses.

Customers other than industrial and institutional customers can also benefit from Grid Performance ESS to meet their reliability needs. Even homes and small businesses can suffer from the effects of voltage fluctuations and momentary outages. For example, overvoltages can damage household electronics and appliances. Elevators and HVAC equipment used in Toronto's extensive multi-unit residential buildings and large commercial buildings are increasingly sensitive to similar reliability disruptions.

During customer engagement, Toronto Hydro received feedback that customers support improving grid performance in parts of the city that experience lower reliability, particularly where it clearly has a disruptive effect on customers.

Given their experiences, sophistication, and insights, key account customers have made them important advisors to Toronto Hydro as the utility works to identify and better understand reliability issues and related customer needs, especially complex challenges such as poor power quality. As of May 2018, Toronto Hydro has 459 customers with loads above 1 MW, including 251 key account customers with ION meters, which are a special type of revenue meter with built-in power quality monitoring.

The approach and technology used to investigate and solve these reliability challenges have evolved over the years from installing mechanical chart recorders that could only identify gross attributes of power supply, to the current use of digital equipment capable of identifying harmonics, fast rising voltage, current fluctuations, and other line disturbances caused by modern switching equipment not previously available for use on the distribution system. Equipment in use today, along with advanced data and information available from upstream and downstream sources, is also able to identify the cause of the disturbance in most cases. Toronto Hydro has learned that some line disturbances can stem from upstream transmission and distribution equipment, and from disturbances on other feeders sharing a common bus.

Figures 2 and 3 below illustrate several types of voltage disturbances, and their respective contribution to the total disturbances across Toronto Hydro's system.

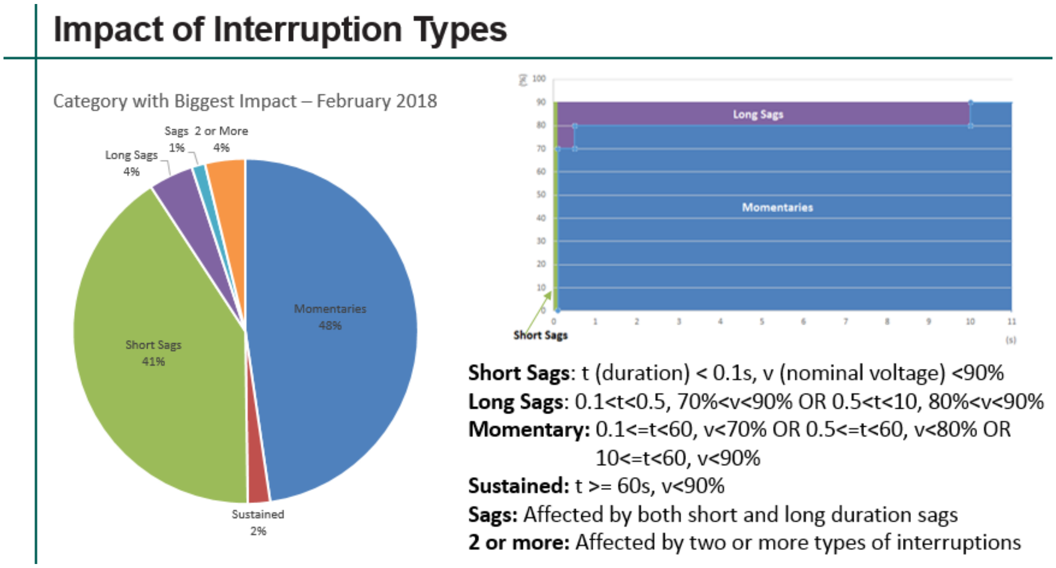


Figure 2: Categories of Line Disturbances

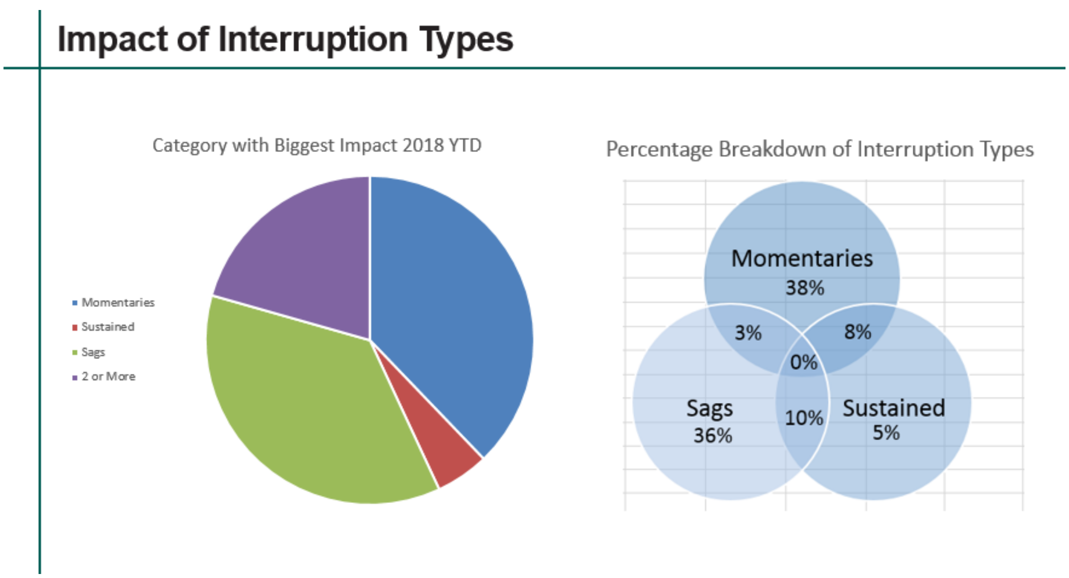


Figure 3: Contribution of Line Disturbances to System Total

Momentary interruptions and voltage sags constitute the vast majority of voltage disturbances on Toronto Hydro's system. These disturbances are typically associated with large current draws on the feeder or bus from large loads coming on line, tree contacts with overhead feeders, and other short duration events such as momentary feeder faults. Toronto Hydro uses an auto-reclose scheme to automatically reclose breakers when they operate due to a fault and then lock out if the fault is not cleared. This practice allows a momentary outage from temporary faults (which are mainly caused by tree contacts with overhead lines) in favour of increasing the frequency of sustained outages. While this practice does serve to minimize sustained outages, the resulting line disturbance can impact other feeders on the same bus and cause power quality problems and service interruption for customers on those feeders if they cannot ride through the line disturbances.

Table 4 below lists the momentary interruptions (excluding voltage sags) associated with transformer stations from 2013 to 2017. Since their duration do not exceed 60 seconds, these momentary events are not reflected in the sustained duration (SAIDI) or frequency (SAIFI) statistics. Voltage sags are tracked at the feeder level using ION meters at customer locations and are not shown in Table 4. However, voltage sags and momentary interruptions are generally closely linked and correlated. As such, the momentary interruption data shown in Table 4 is a useful screening tool for the purposes of addressing voltage sags for customers and prioritizing efforts on feeders associated with those stations.

1 **Table 4: Stations with Momentary Interruptions 2013-2017 (excluding Major Events)**

STATION NAME	2013	2014	2015	2016	2017	AVERAGE
AGINCOURT TS	24	36	27	20	13	24.0
BASIN TS	6	10	9	7	4	7.2
BATHURST I TS	34	24	25	25	24	26.4
BATHURST II TS	25	36	19	24	19	24.6
BERMONDSEY I TS	17	19	19	21	22	19.6
BERMONDSEY II TS	23	21	10	14	15	16.6
BRIDGMAN TS	2	0	4	8	3	3.4
CARLAW TS	8	14	12	22	18	14.8
CAVANAGH TS	38	51	53	48	26	43.2
CECIL TS	1	0	0	0	0	0.2
DUFFERIN TS	32	36	27	44	41	36.0
DUPLEX TS	7	10	8	20	3	9.6
ELLESMERE TS	37	39	46	44	33	39.8
ESPLANADE TS	0	1	0	0	0	0.2
FAIRBANKS I TS	20	18	25	22	21	21.2
FAIRBANKS II TS	15	19	18	11	23	17.2
FAIRCHILD I TS	17	32	37	36	29	30.2
FAIRCHILD II TS	19	13	17	15	16	16.0
FINCH I TS	20	20	21	11	24	19.2
FINCH II TS	24	25	27	30	22	25.6
GLENGROVE TS	9	8	9	11	7	8.8
HORNER TS	43	23	37	35	30	33.6
LEASIDE TS	23	27	16	21	16	20.6
LESLIE I TS	26	20	19	22	23	22.0
LESLIE II TS	32	59	48	29	21	37.8
MAIN TS	8	7	11	5	10	8.2
MALVERN TS	11	31	23	8	8	16.2
MANBY TS	29	42	38	18	31	31.6
REXDALE TS	33	46	25	46	33	36.6
RICHVIEW TS	44	49	59	42	66	52.0
RUNNYMEDE TS	42	37	50	30	29	37.6
SCARBOROUGH EAST TS	20	15	47	17	19	23.6
SCARBOROUGH WEST TS	27	36	32	27	29	30.2
SHEPPARD EAST TS	22	27	22	26	16	22.6
SHEPPARD WEST TS	32	40	34	24	15	29.0
STRACHAN TS	18	18	18	19	12	17.0
TERAULEY TS	0	1	0	0	0	0.2
WARDEN TS	48	46	46	46	51	47.4
WILTSHIRE TS	2	2	2	2	3	2.2
WOODBRIDGE TS	3	4	8	9	4	5.6

As part of Toronto Hydro's efforts to better understand the nature and cause of unacceptable line disturbances, the utility conducted a series of case studies with a number of large customers. Figure 4 and Figure 5 below summarily illustrate the results of these studies. Three of the four cases of poor power quality were traced to upstream anomalies on the transmission and distribution system.

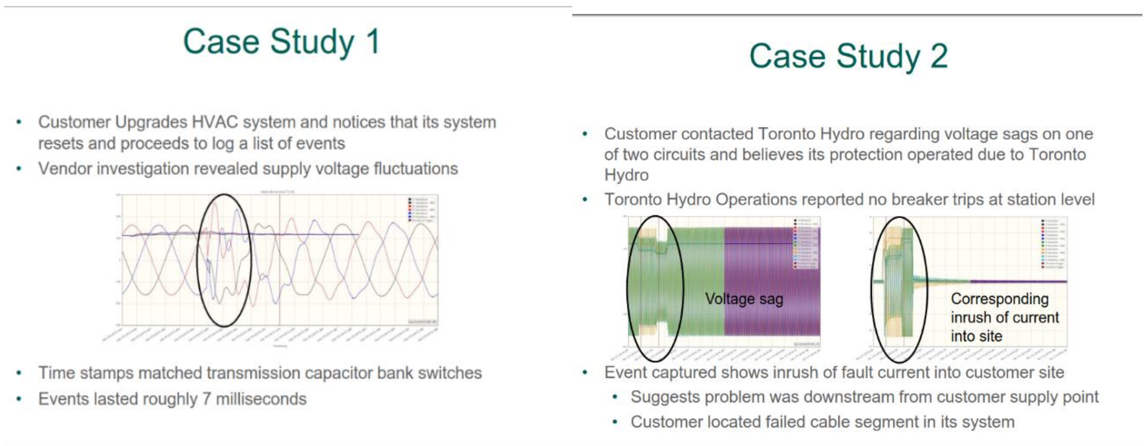


Figure 4: Power Quality Case Studies 1 and 2

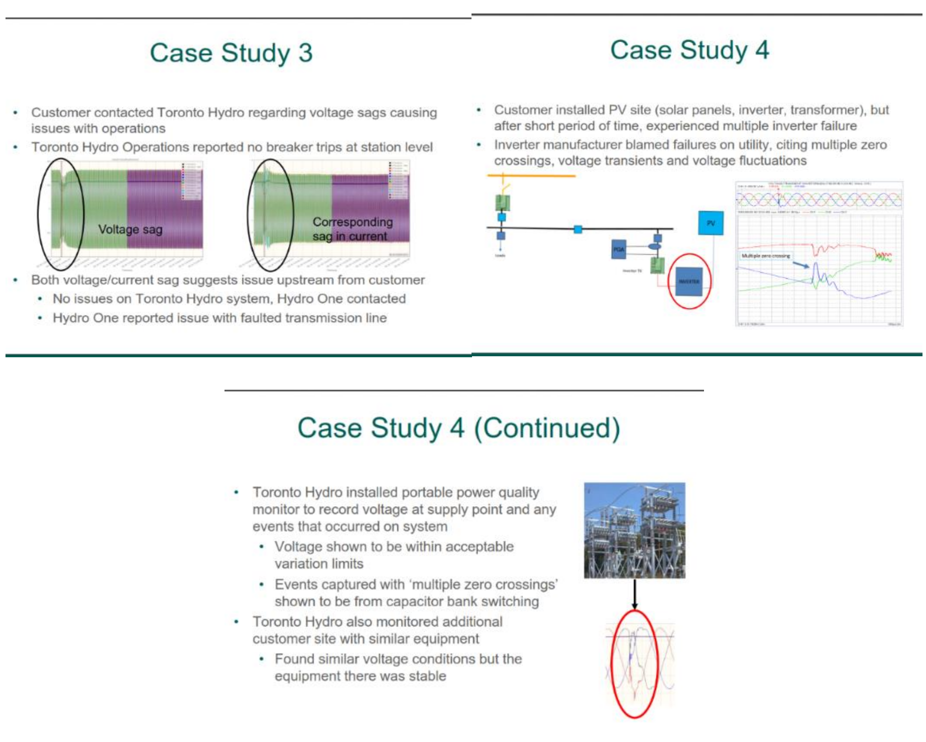


Figure 5: Power Quality Case Studies 3 and 4

In all four case studies, Toronto Hydro deployed power quality monitors to help the customer identify and investigate the disturbances they were experiencing. In particular, with respect to case study 3, power quality monitoring results indicated that voltage sag on the Hydro One transmission system was the root cause of the disturbance that manifested at the customer site. An ESS solution would have been effective in mitigating the impact of such upstream issue on customer operations.

E7.2.2.4 Expenditure Plan

Table 5: Forecast Program Costs- Grid Performance ESS Investments ($ Millions)

	2020	2021	2022	2023	2024
Grid Performance ESS Projects	-	2.7	2.8	-	-

Toronto Hydro proposes to install aggregate capacity of 8 MW/4 MWh of Grid Performance ESS over the forecast period, at a total cost of $5.5 million. These projects will be implemented in 2021 and 2022. Building on the consultations with key account customers and case studies performed to date, Toronto Hydro plans to identify and prioritize suitable sites for Grid Performance ESS investments based on the following screening factors:

1) Feeder has at least one customer with an ION meter (or soon to be installed) that can track the benefits of the Grid Performance ESS;
2) Load criticality, including benefit to vital services and comparative economic contribution;
3) Worst performing feeders; and
4) Benefits to other area customers

To support installations starting in 2021, the screening, customer engagement and selection of key account customers for Grid Performance ESS deployment is proposed to be completed during 2020 along with the required design and procurement. Similarly, the preparatory work necessary to support the 2022 installations is proposed be completed in 2021.

One of the projects considered in this segment involves the 88M43 feeder from Richview TS. As is shown in Table 6 below, between 2015 and 2017, this Richview TS feeder experienced on average 5 momentary interruptions per year (which is the highest out of all transmission stations in Toronto Hydro’s service territory) and 11 potential voltage sage events per year. Customers that would benefit from a Grid Performance ESS on this feeder include a manufacturing facility (1-2 MW peak) that has experienced poor reliability. In this example, Grid Performance ESS would eliminate voltage sags and momentary interruptions, reducing the average number of interruptions for this customer and other customers downstream of the ESS (from 17 to one interruption per year). An ESS could also provide benefits such as outage impact reduction, as described in section E7.2.2.3.

Table 6: Example Customer Reliability (88M43) Prior to Grid Performance ESS

Reliability Statistics	2015	2016	2017	Average
Momentary	5	6	8	**6.3**
Sustained	1	1	2	**1.3**
Hydro One Event	0	0	1	**0.3**
Potential Sag	7	14	22	**14.3**

E7.2.2.5 Options Analysis

1. Option 1: Do nothing

Toronto Hydro has been monitoring and working with key account customers to assess and understand the nature of power quality issues impacting their service and the associated system components. The majority of the feeder disturbances analyzed to date originated upstream of the impacted customers' service entrance equipment. Toronto Hydro has an obligation to address these system issues.

Commercial and industrial customers have informed Toronto Hydro that power quality and reliability are more important considerations than price due to the high cost of service interruptions caused by outages and feeder disturbances[7]. In some cases customers may choose to expand outside the city due to power quality issues, thereby adversely affecting economic growth and employment opportunities within the community.

Toronto Hydro continues to see a rapid pace of DER growth in its service territory, and expects that almost 60 feeders will be unable to support additional renewable generation by 2024. The role of storage in supporting renewable generation is well established. Although the ESS proposed for reliability improvement is not specifically targeted at feeders saturated with DERs, the screening criteria give credit to projects where these synergistic opportunities exist. The candidate feeders and distribution components will benefit from energy storage capacity, through improved reliability, increased efficiency, and expanded capacity for renewable generation.

[7] Exhibit 1B, Schedule 9, Appendix A

The do nothing option is not considered an acceptable solution, since it would not be responsive to customer expectations. Not addressing customer needs will result in continued adverse impact on customer operations (particularly those with sensitive power equipment) and potential economic loss for the customers, utility and local community over time.

2. Option 2: Conventional Wires Options

Conventional wires options can include new feeders, feeder rebuilds, placing lines underground, upgrading stations and building new stations. At the feeder level, a traditional approach is to establish regulated zones on feeders using capacitor banks and reactive power compensators (regulators). Additionally, under load tap changers are often used to increase and decrease line voltage in response to changes in line loading. These traditional approaches to regulation can solve certain power quality issues; however, the dynamic nature of the load along a feeder makes it impossible to achieve adequate regulation in response to load changes and high frequency transients. This technology is too slow to react to line disturbances and voltage can only be adjusted in fixed increments given the design of the tap changers.

Overhead feeders can be placed underground to substantially eliminate momentary interruptions, however such projects are in the order of tens of millions of dollars and cannot be justified based on tree and animal contact avoidance alone. In cases where line disturbances are associated with other feeders on the common bus, more than one overhead feeder may need to be converted to underground. This scale of intervention is inappropriate for solving power quality problems on a feeder segment affecting a relatively small number of customers.

Vegetation management practices, including aggressive cut back, can reduce (not eliminate) tree contacts but must be balanced with City policy and community acceptance given the importance of Toronto's tree canopy. Additionally, animal guards have been applied to reduce animal contacts and resulting feeder disturbances and outages. Different designs have been developed over many years to combat this problem with considerable success. Nevertheless, these designs and activities are insufficient to address the power quality problems these customers experience.

3. Option 3: Conventional Power Electronics Option

The conventional power electronics option involves using regulating devices to mitigate voltage drops (e.g. falling to 50 percent of nominal values for under 10 seconds). Conventional solutions include Static Synchronous Compensator ("STATCOM") and Static VAR Compensator ("SVC").

STATCOMs and SVCs employ power electronics and capacitors to absorb or supply reactive energy in order to regulate voltage. Since capacitors can store a very limited amount of energy, neither STATCOMs nor SVCs are intended to function as energy sources for the purpose of supplying load. As a result, they can provide limited benefit to customers. The differences between STATCOMs and SVCs include stability under varying voltage levels, response speed, and harmonic emissions.

Due to their limited capabilities and benefits, the deployment of STATCOMs and SVCs are not recommended as a solution.

4. Option 4: Do More and Accelerated Spend Options

Grid Performance ESS is an emerging segment based on evolving battery technology functionality, declining ESS costs, and changing customer needs and preferences. There is a risk that these drivers of adoption may prompt more customer interest in Grid Performance ESS than forecasted. There is also a risk that upon closer examination of Customer-Specific ESS projects, one or more of those projects may be reclassified as Grid Performance ESS.

5. Option 5 (Selected Option): Proposed Solution

The installation of appropriately sized Grid Performance ESS on the distribution system offers the best solution to address the upstream line disturbances impacting Toronto Hydro's customers. This solution offers targeted, local line regulation and ride-through capacity for significant reliability events, including voltage sags on feeders. Battery ESS is a "non-wires alternative" that has the ability to offer a lower cost alternative to conventional distribution infrastructure investment. It can also provide additional system and customer benefits that cannot be provided by conventional wires options. These benefits include outage reduction, peak shaving/shifting, and renewable generation enablement.

E7.2.2.6 Execution Risks and Mitigation

These are addressed for the entire ESS program in Section 7.2.5.

E7.2.3 Renewable Enabling ESS

E7.2.3.1 Outcomes and Measures

Table 7: Outcomes & Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by enabling customer investments in renewable energy and reducing energy costs.
Reliability	• Contributes to service reliability.
Financial	• Contributes to Toronto Hydro's financial objectives and performance by enabling the deferral of system generation, transmission, and distribution investments.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Creating the stacked benefits of utility ESS projects that were recognized in the 2017 Long-Term Energy Plan ("LTEP"); ○ Reducing GHG emissions by enabling the proliferation of energy storage, DERs, and grid-modernization; and ○ More effectively utilizing surplus off-peak power, thereby optimizing distribution and infrastructure costs.

E7.2.3.2 Drivers and Need

Table 8: Program Drivers

Trigger Driver	Public Policy
Secondary Driver(s)	System Efficiency

Applicable policy and economic conditions, together with the preferences of customers and consumers, have facilitated a steady interest in distributed renewable generation projects within Toronto Hydro's service territory. This trend is expected to continue into the foreseeable future. In addition, the decreasing costs of photovoltaic panels, coupled with the end of the IESO's FIT program, have generated growing interest in the net metering initiative, including continued customer investment in renewable energy resources in the distribution system.

Based on historical trends and given the end of the FIT program in 2018, Toronto Hydro anticipates the pace of renewable energy generation ("REG") connections will begin to slow by 2019. However, forecasted REG installations will be larger in size as compared to years past due to cost reductions in solar photovoltaic panels and net metering benefits. Between 2019 and 2024, Toronto Hydro forecasts that about 830 additional REG connections (totaling 69 MW) will be connected to its distribution system, as shown in Figures 6 and 7 below.

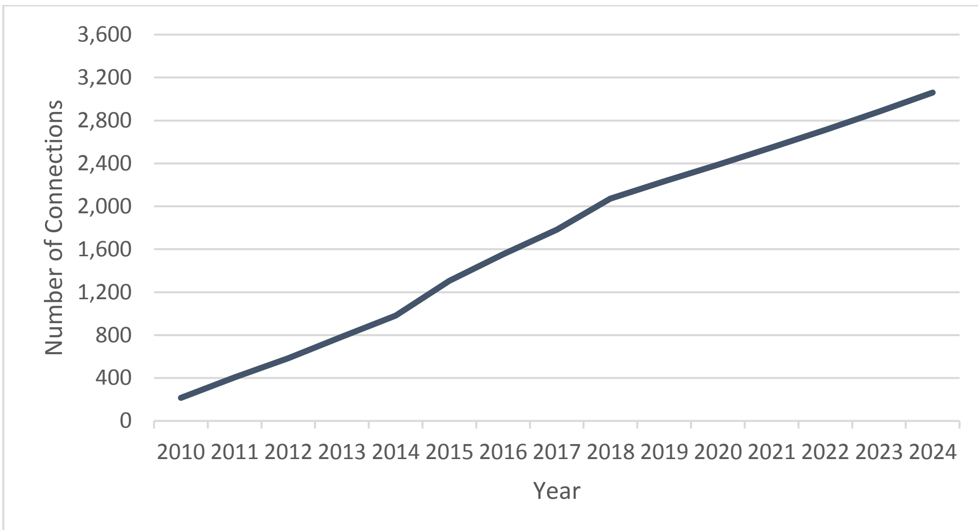


Figure 6: Forecast Renewable Generation Connections

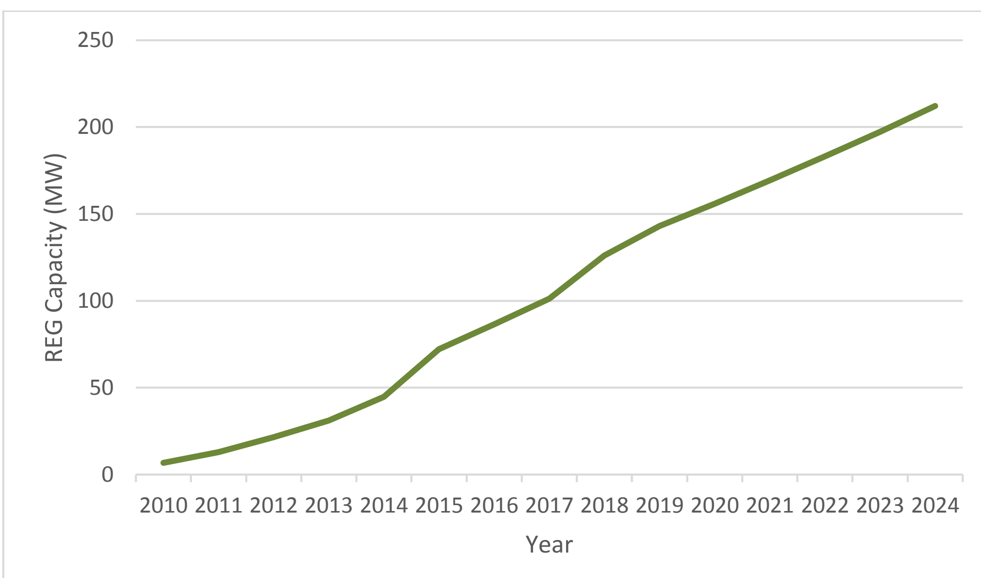
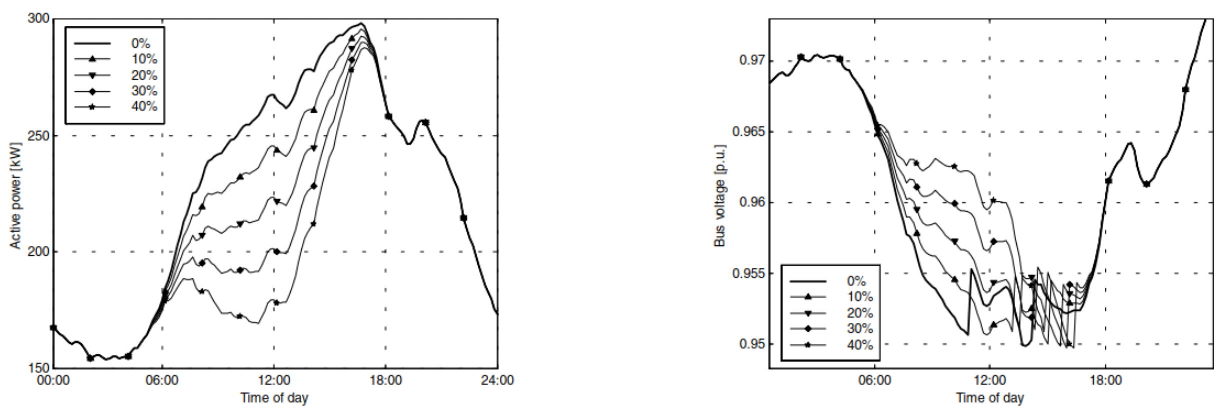


Figure 7: Forecasted Renewable Generation (MW)

Due to the expected demand for renewable generation at the distribution level, there has been a fundamental change in the power flow conditions of the distribution system, which has challenged the conventional radial nature of the grid to accommodate bi-directional power flow. Large scale deployment of REG (e.g. solar PV) causes issues in distribution system planning and operations such as reverse power flow, unintentional islanding and overvoltage on feeders. As a result, Toronto Hydro must proactively manage generation connections on feeders in order to accommodate future growth.

To illustrate the effect of REG on distribution line voltages, Figure 8 shows the load and voltage profiles at a system bus with various levels of REG on the bus.[8] As depicted, bus load begins to rise at the start of the workday at 6am. As generation comes online to support the local load demand, bus load is offset by this generation output and the bus voltage drops. As generation comes offline toward the end of the day, bus loads rise again and line voltages return to their nominal values. The higher the REG to load ratio, the more pronounced these effects become with a higher risk of potential islanding.



a) Active power at bus 53 **b) Voltage at bus 53**

Figure 8: Impacts of Renewable Generation on Bus Voltage

In the past few years, there have been numerous studies, standards and guidelines with respect to REG integration, such as IEEE Standard 1547 (Interconnecting Distributed Resources with Electric

[8] M. Begovic et. al., *Impact of Renewable Distributed Generation on Power Systems*, Proceedings of the 34th Hawaii International Conference on System Sciences (2001), available at <https://pserc.wisc.edu/ecow/get/publicatio/2000public/CSSAR01.PDF>.

Power Systems) and National Renewable Energy Laboratory's ("NREL")[9] High Penetration PV Integration Handbook for Distribution Engineers (NREL Handbook). These documents outline methods and practices to determine the maximum allowable generation on the distribution system (e.g. that DR aggregate capacity is less than one-third of the minimum load of the Local Electric Power System ("EPS")). As the ratio of generation capacity to minimum load[10] increases, the amount of time required by inverters to respond to anti-islanding scenarios increases and the likelihood of effective inverter response to anti-islanding scenarios decreases.

Toronto Hydro conducted an analysis for all feeders in its system to establish generation to minimum load ratios, stiffness factors[11], and fault ratio factors[12] in accordance with applicable guidance of the NREL. The study found that 13 feeders currently exceed the one third generation to minimum load screening ratio outlined by the NREL Handbook. It was also determined that if short circuit capacity constraints at the transformer station were ignored, given the forecast growth in REG, by 2024, an additional 45 feeders would exceed the generation to minimum load ratio.

These findings indicate a high penetration of REG in certain parts of Toronto Hydro's distribution system, which will increase the probability of serious issues such as unintentional islanding conditions. This will adversely affect the utility's ability to safely and reliably connect additional REG to the distribution system and, if not addressed by proactive investments, could ultimately lead to an increase in declined applications for connections in a region with a growing appetite for REG. An overview of these findings, as well as the ESS required to address expected exceedances of the generation-to-minimum load ratio, can be found in Table 9 below.

[9] The National Renewable Energy Laboratory (NREL) specializes in renewable energy and energy efficiency research and development and is a reputable authority on the level of penetration of renewables on electricity systems. It is a government-owned, contractor operated facility that is funded through the United States Department of Energy.
[10] Determined as the ratio of aggregate DG capacity on a particular power system section to the annual minimum load on that power system section.
[11] Determined as available utility fault current divided by DG rated output current in affected area.
[12] Determined as available utility fault current divided by DG fault contribution in affected area.

Table 9: Generation to Minimum Load Ratio Summary for Toronto Hydro Feeders

	Generation to Minimum Load Ratio					
	Existing – Dec 2017			Outlook by 2024		
Description	**> 1/3**	**> 1/2**	**2/3**	**> 1/3**	**> 1/2**	**2/3**
No. of Feeders Exceeding Applicable Ratio	13	0	0	58	51	31
ESS Required to Mitigate All Feeders to Applicable Ratio	5.8 MW/ 23.3 MWh	N/A	N/A	156 MW/ 624 MWh	62.5 MW/ 250 MWh	24.5 MW/ 98 MWh

Renewable Enabling ESS can be deployed on such feeders in order to lower the generation to minimum load ratio. At times during the day when the ratio is high, the ESS can function like a load by absorbing energy; whereas when the ratio is low, the ESS can act like a generator by supplying energy.

An overview of the analysis of seven representative feeders on Toronto Hydro's system can be found in Table 10 below.

Table 10: Generation Screening Ratio - 2024 Outlook Summary for Four Toronto Hydro Feeders

Feeder Name	TS Station - Bus	Region	Minimum Load (MW)	Existing DER (MW)	Gen to Load Ratio (Existing)	DER Outlook (MW)	Gen to Load Ratio (2024 Outlook)
51-M32	*Leslie – Q*	North York	2.39	0.45	0.19	1.09	0.46
51-M25	*Leslie – J*		2.58	1.68	0.17	2.23	0.38
80-M27	*Fairchild – J*		2.01	0.01	0.00	1.03	0.51
63-M6	*Agincourt – Y*	Scarborough	6.88	2.93	0.43	4.10	0.60
47-M1	*Sheppard – B*		3.54	1.76	0.50	2.15	0.61
R29-M36	*Rexdale – Q*	Etobicoke	3.82	0.88	0.23	1.78	0.47
11-M5	*Runnymede - B*	Toronto	2.63	0.39	0.15	1.04	0.39

Table 10 provides the NREL screening ratios for seven feeders in Etobicoke, North York, Scarborough and the former City of Toronto. The assessment indicates the following findings:

- **63-M6 & 47-M1 (Scarborough)**: already exceeds generation to minimum load ratio (in red);
- **51-M32 & 51-M32 (North York), R29-M36 (Etobicoke)**: currently have moderate generation to minimum load ratio for (orange); and
- **51-M32, 51-M25, 80-M27, R29-M36 & 11-M5**: exceeds generation to minimum load ratio for 2024 Outlook

In short, the screening ratios show that by 2024 all seven feeders will have a high penetration of PV generation and that they all will require grid investments or other solutions to ensure the safety of the grid and allow further REG connections.

As part of its DER process, Toronto Hydro offers a pre-application report for its customers, providing information about the proposed point of interconnection so the customer can determine if a DER system installation is worth pursuing. This process also allows Toronto Hydro the opportunity to gauge customer interest in DER and forecast potential DER growth on its distribution system. Pre-application reports help customers prepare successful applications while avoiding the need for Toronto Hydro to perform detailed studies on applications that are not likely to be proceed due to customer concerns.

The pre-application process also allows Toronto Hydro to discover potential distribution system issues that must be addressed to accommodate the proposed DER. In such instances, Toronto Hydro would work with the customer to find the best solution to move the DER installation forward, such as modifying the proposed system to satisfy the pre-application screening. Although Toronto Hydro has been able to manage DER customer expectations to date through this pre-application process, the distribution system is approaching its technical limits and Renewable Enabling ESS investments will be required to accommodate future DER growth.

When assessing the potential to connect a DG project, Toronto Hydro planning engineers determine if a feeder's phase current imbalance exceeds 10 percent of the total load on the feeder (at the station) when DG is added to the feeder. Phase imbalances in general result in a return current on the neutral conductor, causing line losses and, in cases of considerable imbalance, cable splice failures due to overheating. If the DG causes the current imbalance to exceed the 10 percent threshold, the imbalance must be corrected. One such correction method is to redistribute load among the other phases of the feeder, which is technically and operationally complex. Where load distribution is not possible, DG applications must be rejected. Renewable Enabling ESS can address this issue by dynamically balancing phases to respect the 10 percent threshold, without having to redistribute load to different phases. In both the short and long term, this approach is expected to resolve connection barriers for many projects seeking connection in a local area.

ESS is recognized as an effective distribution system solution to increase the PV connection capacity. [13] Not only does ESS present remarkable synergies with REG, Renewable Enabling ESS can also be used to improve system performance by reducing outage impact and shifting/shaving feeder peaks, as described in section 7.2.2.3.

E7.2.3.3 Expenditure Plan

Table 11 and Table 12 below summarize the REI ESS Program plan for 2015-2019.

Table 11: 2015-2019 CIR – Renewable Enabling Investments (Projects)

Assets (Units)	2015	2016	2017	2018	2019	Total (Units)
Local Support Energy Storage (LSES) System *(100 kW × 1 hr)*	1	2	3	3	3	12
Grid Support Energy Storage (GSES) System *(200 kW × 2.5 hrs)*	1	1	2	2	2	8
Municipal Station Energy Storage (MSES) System *(400 kW & 3 hrs)*	0	1	1	1	1	4

Table 12: 2015-2019 CIR – Renewable Enabling Investments ($ Millions)

	2015	2016	2017	2018	2019	Total
REI Investments	**$0.54**	**$1.09**	**$2.16**	**$3.24**	**$3.78**	**$10.8**

Table 13 below summarizes the actual and bridge year investments over the 2015-2019 period.

Table 13: Actual and Bridge Costs- Renewable Enabling Investments ($ Millions)

	Actual			Bridge	
	2015	2016	2017	2018	2019
REI Investments	-	-		**$5.9**	**$2.0**

[13] For example, see:
(i) J. Seuss, M. J. Reno, et al, “Improving distribution network PV hosting capacity via smart inverter reactive power support”, Proc. IEEE PES General Meeting, July 2015, pp. 1–5.
(ii) Z. Waclawek, et al, “Sizing of photovoltaic power and storage system for optimized hosting capacity”, Proc. IEEE International Conference on Environment and Electrical Engineering, June 2016, pp. 1–5.
(iii) B. P. Bhattarai, et al, “Overvoltage mitigation using coordinated control of demand response and grid-tied photovoltaics”, Proc. IEEE SusTech, Jul 2015.
(iv) F. Capitanescu, et al, “Assessing the potential of network reconfiguration to improve distributed generation hosting capacity in active distribution systems”, IEEE Transactions on Power Systems, Jan 2015, vol. 30, no. 1, pp. 346–356.
(v) Y. Takenobu, et al, “Maximizing hosting capacity of distributed generation by network reconfiguration in distribution system”, Proc. Power Systems Computation Conference (PSCC), June 2016, pp. 1–7.

1. 2015-2019 CIR Energy Storage Systems ("ESS") Program

The 2015-2019 ESS program presented in the 2015-2019 CIR was designed to improve system efficiency, reliability and power quality, and to enable the connection of renewable generation and electric vehicles. Toronto Hydro's original plan involved $10.8 million to support 24 ESS installations. These were spread across 12 Local Support Energy Storage ("LSES") systems, eight Grid Support Energy Storage ("GSES") systems and four Municipal Station Energy Storage (”MSES”) systems. The original plan was subsequently modified to reflect technology advancements and emerging customer needs. In the meantime, Toronto Hydro has been implementing various energy storage pilot/innovation projects and connecting customer storage projects. The data, experience and lessons learned from these projects have helped Toronto Hydro to:

- understand the benefits and requirements for safely integrating ESS into the distribution system;
- learn from the experiences of host customers regarding the benefits they derive from ESS;
- plan and design the 2020-2024 ESS projects;
- modernize the grid and prepare for future growth;
- satisfy customer desire to invest in innovative technologies; and
- explore new opportunities for both customers and Toronto Hydro to realize the benefits of DER.

By the end of 2019, Renewable Enabling ESS projects will be completed on two feeders with the highest generation to minimum load ratio, located at Sheppard TS and Agincourt TS, as further discussed below.

a. 2018- 2019 Forecast Expenditures

Based on applicable guidelines and supporting business cases, Toronto Hydro plans to install two Renewable Enabling ESS units totalling approximately $7.9 million with aggregate capacity of 3.75 MW/15 MWh to help mitigate existing generation to minimum load issues for two feeders over the 2018-2019 period. An overview of the candidate feeders, along with the sizing and cost of each ESS unit is detailed in the table below.

Table 14: Renewable ESS

No.	Feeder Name	Station	Bus	Gen to Min Load Ratio	ESS (MW)	ESS (MWh)	ESS Cost ($M)
1	***47-M1***	*Sheppard TS*	B	0.50	1.75	7.0	3.6
2	***63-M6***	*Agincourt TS*	Y	0.43	2.00	8.0	4.3
Total					**3.75**	**15**	**7.9**

2. 2020- 2024 Forecast Expenditures

During 2020-2024, Toronto Hydro plans to install three Renewable Enabling ESS units totalling approximately $5 million and 2.35 MW/9.5 MWh to help mitigate forecasted generation to minimum load levels at three feeders.

Table 15: Forecast Program Costs- Renewable Enabling ESS Investments ($ Millions)

	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**
REI Investments	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**

As mentioned earlier, due to forecasted DER growth by 2024, an additional 45 feeders on Toronto Hydro's distribution system will exceed the generation to minimum load ratio. Therefore, the necessary ESS required to mitigate these issues on all the feeders will range in size from 0.35 MW/1.4 MWh to 9 MW/36 MWh and range in cost from $0.8 million to $19 million. In order to mitigate all these feeders with ESS, it would cost roughly $217 million. As this cost figure indicates, ESS is not always the most economic REI option. Having regard to economics and other benefits, Toronto Hydro has planned wires solutions in most of these instances while proposing $5 million for Renewable Enabling ESS. The table below provides an overview of the proposed ESS projects for the feeders that are suitable for Renewable Enabling ESS investments.

Table 16: Feeders Proposed for Renewable Enabling ESS

No.	Feeder	Station	Bus	Gen to Min Load Ratio	ESS (MW)	ESS (MWh)	ESS Cost ($M)	ESS Start Year	ESS Completion Year
1	***51-M25***	*Leslie TS*	J	0.38	0.35	1.40	$0.8	2020	2020
2	***51-M32***	*Leslie TS*	Q	0.46	0.90	3.60	$1.9	2020	2022
3	***80-M27***	*Fairchild TS*	J	0.51	1.10	4.50	$2.3	2022	2024
TOTAL					**2.35**	**9.50**	**$5.0**	-	-

Toronto Hydro plans to pace the work uniformly in each year during 2020-2024. To accomplish this pacing, Toronto Hydro will commence work on the 51-M25 Leslie feeder in 2020, the 51-M32 Leslie feeder over three years (2020 to 2022), and the 80-M27 Fairchild feeder over three years (2022 to 2024).

Based on industry studies, Renewable Enabling ESS can be installed anywhere along a feeder in order to help mitigate concerns regarding generation to minimum load ratio. Therefore, to avoid additional costs, the proposed ESS units could potentially be connected to existing Toronto Hydro assets (i.e. padmounted transformers) that can accommodate the nameplate capacity and necessary footprint and layout. If such assets and locations cannot be established, then new assets (i.e. transformer) will be installed to accommodate the proposed ESS.

E7.2.3.4 Options Analysis

1. Option 1: Do nothing

Some feeders in Toronto Hydro’s territory currently exceed the acceptable generation to minimum load ratios and more than 50 feeders are forecast to exceed acceptable ratios by 2024. If no action is taken, forecast demand for DG, including REG, cannot be safely accommodated in Toronto. This would put Toronto Hydro in non-compliance with its obligation to connect renewable generation (i.e. pursuant to Section 6.2.4 of the Distribution System Code). Further, customers willing to invest in modernizing the grid will be frustrated, and the associated grid and upstream benefits will not be realized, contrary to the opportunities identified in the Long-term Energy Plan.

2. Option 2: Traditional ”poles and wires” solutions

Traditional “poles and wires” solutions include upgrading or constructing additional primary distribution infrastructure (e.g. feeder lines, cables, transformers), modifying protection schemes, implementing direct transfer trip schemes and installing monitoring and control devices. Given the current state of technology and associated costs, traditional solutions are the best option to enable the connection of DER in most cases (but not in all cases). While Toronto Hydro has the Generation Protection Monitoring & Control program to address system-wide issues to enable DER, some localized areas would still experience issues involving generation to minimum load ratio and/or feeder phase imbalances, which can inhibit the connection of a DER project. These specific issues can be addressed with a targeted deployment of ESS.

Feeder re-configurations could also be performed to increase load on forecasted feeders where generation to minimum load ratios are high. However, this method may decrease reliability and may not always be feasible due to the existing network configuration.

3. Option 3: Production Curtailment and Decreasing Operational Margin

With better resource monitoring/forecasting and real-time estimation of the grid capacity, applicable operational margins can be reduced. This in turns allows the existing infrastructure to be used more efficiently and to a greater extent (i.e. with a higher capacity factor). For more detailed information regarding this option, please refer to the Generation Protection, Monitoring, and Control Program.[14]

Curtailment occurs when plants are required to reduce their generation output in order to maintain the operational limits of the grid. This may entail a small gradual decrease of the production (referred to as soft curtailment) or a complete stop to production through measures such as inter-tripping (referred to as hard curtailment). Soft curtailment requires a communication infrastructure and methods to assess the real-time performance of the grid and the appropriate production decrease. In a deregulated market without vertically integrated utilities, it requires willingness from grid users to participate and a legal framework enabling such participation. Moreover, economic arrangements are required to allocate the loss of income stemming from curtailed production.

As such, curtailment is not currently seen as a viable option.

4. Option 4: Do More and Accelerated Spend

Renewable Enabling ESS is customer driven. Spending more or spending more quickly than forecasted is a risk associated with any customer driven program. The proposed option is based on forecasted uptake of distributed renewable generation in the service area.

5. Option 5 (Selected Option): Proposed Solution

The proposed Renewable Enabling ESS program will provide Toronto Hydro with strategic capabilities to address specific issues relating to DG/REG enablement in targeted areas of its distribution system. It will allow Toronto Hydro to mitigate the problems described in sub-section 1 of Section 7.2.3.2 and fulfill its regulatory obligations to connect REG projects pursuant to the DSC. The proposed solution also best positions Toronto Hydro to support the goals of the Long-Term Energy Plan with respect to

[14] Exhibit 2B, Section E5.5

enabling renewable generation and deploying energy storage. It is expected that these investments will enable the aggregate connection of 5 MW of REG which would otherwise be constrained. The overall cost of this option is an estimated $5 million over the 2020 to 2024 period.

E7.2.3.5 Execution Risks and Mitigation

These are addressed for the entire ESS program in Section 7.2.5.

E7.2.4 Customer Driven ESS

E7.2.4.1 Outcomes and Measures

Table 17: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Reducing power outages and customer interruption costs. ○ Providing backup power during emergency situations for critical customers (e.g. emergency services, hospitals, government buildings etc.). ○ Enabling Global Adjustment relief for Class A customers. ○ Providing future opportunity to leverage DR and grid capacity relief, thereby avoiding or deferring the need for distribution infrastructure investments.
Reliability	• Contributes to Toronto Hydro's system reliability objectives and performance by enhancing power quality, and ensuring dynamic feeder voltage support, low harmonics and uninterrupted service.
Financial	• Contributes to Toronto Hydro's financial objectives and performance by supporting the satisfaction and retention of load customers and the deferral of conventional infrastructure upgrades.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Creating the stacked benefits of utility ESS projects that were recognized in the 2017 Long-Term Energy Plan (LTEP); ○ Reducing GHG emissions by supporting the proliferation of energy storage, DERs, and grid-modernization; and ○ More effectively utilizing surplus off-peak power, thereby optimizing distribution and infrastructure costs.

E7.2.4.2 Drivers and Need

Table 18: Program Drivers

Trigger Driver	Reliability
Secondary Driver(s)	Customer Economics

1. Evaluating Customer-Specific Need

As set out in section 7.2.2 (the Grid Performance ESS segment), ESS can be deployed to mitigate or resolve a number of issues for the benefit of customers. In the case of Grid Performance ESS, each project is expected to benefit multiple customers. In the Customer-Specific ESS segment, each project is expected to predominantly benefit a single customer.

Customer-Specific ESS allows Toronto Hydro to respond to customer-specific needs with a non-wires solution. This approach differs from the common industry practice of pursuing wires solutions (e.g. dedicated transformers, feeders, and transformer stations) to address customer-specific needs. Customer needs are typically made known to Toronto Hydro as part of a new or upgraded connection request or the ongoing dialogue between Toronto Hydro and customers. Customers' needs often involve increased capacity or reliability, which are driven as a function of changes in their operations. In collaboration with Toronto Hydro engineers and other professionals, customers and their advisors carry out options analysis, including cost forecasts. Given its improving functionality and decreasing costs, ESS is becoming an option that is attracting customer inquiry or being recommended by Toronto Hydro as an alternative for customer consideration. Working together with customers, Toronto Hydro ultimately arrives at a plan that will address their needs without adversely affecting grid reliability or other customers connected to the grid.

As options are reviewed with the customer driving the investment, Toronto Hydro examines whether that customer's need will be addressed through wires or non-wires investments already planned on that feeder (e.g. feeder capacity upgrades) or in the area more generally (e.g. feeder reconfigurations). If so, Toronto Hydro consults with the customer whether the timing of the investments and expected service improvements will meet relevant needs. Based on such feedback, adjustments can be made in some cases to the planned project to better address the needs of the customer.

Where a customer-specific investment closely aligns with work required to address the needs of other customers, the investment (whether in an ESS or wires solution) will proceed as a Grid

Performance project, and associated costs are considered part of the regular investment in the distribution system funded through rate base.

In other cases, customer-specific needs require an investment that only benefits that customer. While a wires solution (e.g. a dedicated feeder) is still appropriate in many situations, customers are increasingly interested in considering non-wires alternatives (e.g. Customer-Specific ESS) as part of the options analysis. Alternatives that entail individualized customer benefits result in costs that are outside of the utility's distribution system investment in the normal course. In accordance with the beneficiary pays principle, these costs are presumptively fully allocated to the customer who benefits. The customer pays for these costs through a capital contribution. As a result of the capital contribution, the asset enters rate base with a net $0 value. This is true for both wires and non-wires customer-driven investments.

2. Customer Need for Behind the Meter Investment

In addition to the above-noted customer needs, Toronto Hydro customers who are billed on a non-coincident demand basis have another need: reducing their peak demand in order to reduce their electricity bills. If these customers draw less electricity from the grid during their peak demand hour each month, they lower their electricity bill.

A subset of these customers (i.e. Class A customers) are also eligible for the Industrial Conservation Initiative ("ICI"), which creates a similar but unique need. If these customers can reduce their demand during the top five provincial peak hours of the year, their Global Adjustment charges can be reduced (potentially by a large amount) in the subsequent year. Since those five peak hours are not known until the end of the one year period, customers undertake demand reduction and peak-shaving activities multiple times per year in order to increase their chances of reducing their Global Adjustment charges.

In addition to benefiting specific customers, these load shifting investments could also have the aggregate effect of lowering the overall Ontario peak demand, thus alleviating costs throughout the electricity system for generation, transmission, and distribution. This is the intended result of the hourly price market, demand response programs, and the ICI.

Customer-Specific ESS can help Toronto Hydro customers achieve the desired peak shaving – whether as a stand-alone benefit or in tandem with other customer benefits. ESS can store electricity during non-peak hours and discharge it during peak hours. The same ESS can be used to improve customer-specific reliability, such as power quality enhancements, momentary outage avoidance, and increased resiliency. As such, the customer can derive both financial and reliability benefits from the same ESS asset. The costs of the investment are presumptively fully allocated to that customer, as discussed above.

Customer reliability needs can be met regardless of whether the ESS is located "in front of the meter" (i.e. traditionally thought of as "grid side") or "behind the meter" (i.e. traditionally thought of as "customer side"). That is, the physics of ESS confers distribution service benefits to the customer in either scenario. For this reason, if reliability were the only customer need that Toronto Hydro needed to address, the distribution asset would typically be located in front of the meter.

However, to meet the customer's financial need, Toronto Hydro has to site the ESS behind the meter, so that it can draw electricity during non-peak hours (for which the customer would incur the associated charges) and discharge during potential peak hours to achieve peak-shaving.

Customers generally prefer to meet both their reliability need and financial need through a single, economically efficient investment. In response, Toronto Hydro proposes to meet that need with Customer-Specific ESS projects that are located where customer benefits can be maximized.

E7.2.4.3 Expenditure Plan

Table 19 shows the gross capital expenditures for the Customer-Specific ESS segment, which is entirely funded by capital contributions from the beneficiary customers. The net impact to Toronto Hydro rate base is $0 over the 2015-2024 period.

Table 19: Bridge & Forecast Customer-Specific ESS ($ Millions)

	Bridge		Forecast					Total
	2018	2019	2020	2021	2022	2023	2024	
Metrolinx ECLRT	9.6	17.7						**27.3**
Metrolinx FWLRT			6.0	10.0				**16.0**
TTC Arrow Garage			12.3					**12.3**
Metrolinx Willowbrook Yard			6.0	2.1	5.9			**14.0**
Total	**9.6**	**17.7**	**24.3**	**12.1**	**5.9**	**0.0**	**0.0**	**69.6**

1. 2018-19 Forecast Expenditure Plan

Metrolinx Eglinton Crosstown Light Rail Transit ("ECLRT") ESS: Currently in construction, this Customer-Specific ESS project will provide emergency power, improve reliability, and reduce emissions for the ECLRT.

The ECLRT ESS is planned to be in-service in 2019, and will consist of a 10 MW/30 MWh battery system and a 100 kW PV system. The total cost of $27.3 million will be fully recovered through customer capital contribution. Located behind the meter, the ESS will enable peak-shaving by reducing coincident and non-coincident peak demand from the grid.

The ECLRT itself will span approximately 20 kilometres, starting at Mt. Dennis, located in the west-end of the city, and terminating at Kennedy station, located in the east-end of the city. The Eglinton Maintenance and Storage Facility Yard ("EMSF") will serve as a supply and charging station and will be fed by two Toronto Hydro feeders at the Mt. Dennis station.

In order to improve system reliability, resiliency and flexibility and to proactively manage power supply during peak demand periods, the ESS is designed to operate during both emergency and non-emergency scenarios. More specifically, it will provide backup power generation with the capability to deliver all the required electricity for the ECLRT traction power, including electricity required for the purposes of emergency ventilation.

ECLRT will be mainly supplied by new feeders originating from the new Runnymede TS bus that is currently in construction. From 2014 through 2017, feeders on the Runnymede TS BY Bus averaged 7.2 sustained interruptions annually. The ESS is expected to reduce the number of sustained interruptions by over 50 percent. Momentary interruptions ("MAIFI") are expected to be minimal with the new underground feeders supplying ECLRT.

2. 2020-24 Forecast Expenditure Plan

Three customers have requested that Toronto Hydro complete ESS projects from 2020-2024 to meet their distribution service needs. These projects will be designed to provide reliability improvements, peak-shaving financial relief and emergency resiliency capacity. Toronto Hydro has determined that satisfying these needs will require discrete projects, the benefits from which are only expected to accrue to each requesting customer. Accordingly, the projects are categorized as Customer-Specific

ESS investments. The requesting customers will make capital contributions such that there will be a zero net effect on rate base in the 2020-2024 period.

The proposed Customer-Specific ESS projects are discussed below.

a. Metrolinx Finch West Light Rail Transit ("FWLRT") ESS

Metrolinx's Finch West Light Rail Transit ("FWLRT") is an 11-kilometre light rail transit line that will connect the TTC's Finch West subway station (on the Yonge-University Line) to Humber College westward along Finch Ave.

The FWLRT ESS will consist of a 8 MW/24 MWh battery system across four sites. The cost of this Customer-Specific ESS project is $16 million with a planned in-service date of 2022. The project is fully funded by the customer who is responsible for capital contributions. It will provide reliability improvement, enhanced resiliency, financial relief through peak-shaving, as well as emergency power to ensure service continuity and support underground station ventilation in a sustained grid outage. During normal operation, the ESS will continuously condition the incoming supply and reduce peak demand for the FWLRT, contributing to lower GHG emissions. The ESS will be located behind the meter, enabling peak-shaving by reducing coincident and non-coincident peak demand from the grid.

FWLRT will be supplied by feeders originating from the Finch TS BY Bus. According to Toronto Hydro's feeder reliability estimate (based on the ten feeders served by that bus), feeders on the Finch TS BY Bus averaged 5.1 sustained interruptions annually between 2014 through 2017. The ESS is expected to reduce sustained interruptions, momentary interruptions, and voltage sags by over 50 percent.

b. TTC Arrow Road Garage ESS

This large TTC public transit garage is located on Arrow Road near Finch Avenue and Highway 400 in the north end of Toronto. The TTC is investing in the facility such that it is expected to eventually support approximately 250-300 electric buses.

The TTC Arrow Road Garage ESS project will provide reliability improvements, resiliency, financial relief through peak-shaving, and emergency capacity. The cost of this Customer-Specific ESS project is $12.3 million with a planned in-service date of 2020. The project is fully funded by the customer through capital contributions. The ESS will be located behind the meter, enabling peak-shaving by reducing coincident and non-coincident peak demand from the grid.

The TTC Arrow Garage ESS will consist of a 5 MW/20 MWh battery system. The ESS will augment planned feeder upgrades at this site as part of the customer's project to deploy electric buses. During normal operation, the ESS will continuously condition the incoming supply and reduce peak demand for the TTC Arrow Garage.

Arrow Road Garage is supplied by a feeder (55-M29) originating from the Finch TS JQ Bus. During 2014-2017, 55-M29 averaged 4.5 sustained interruptions annually. The ESS is expected to reduce sustained interruptions, momentary interruptions, and voltage sags by over 50 percent.

3. Metrolinx Willowbrook Yard ESS

Metrolinx operates a large rail maintenance yard at Willowbrook in Etobicoke which services the busy regional rail lines on the lakeshore corridor.

The Willowbrook Yard ESS consists of a 8 MW/24 MWh battery system. The cost of this Customer-Specific ESS project is $14 million with a planned in-service date of 2022. The project is fully funded by the customer through capital contributions. It will provide reliability improvements, resiliency, financial relief through peak-shaving and emergency power.

During normal operation, the ESS will continuously condition the incoming supply and reduce peak demand for Willowbrook. The ESS will be located behind the meter and enable peak-shaving by reducing coincident and non-coincident peak demand from the grid.

Willowbrook Yard is supplied by a feeder (R30-M8) originating from the Horner TS BY Bus. During 2014-2017, R30-M8 averaged 5.1 sustained interruptions annually. The ESS is expected to reduce sustained interruptions, momentary interruptions, and voltage sags by over 50 percent.

E7.2.4.4 Options Analysis

This section examines other potential options for addressing the issues.

1. Option 1: On-Site Generation Options

Customers can consider on-site generation to provide some degree of reliability, financial benefits (i.e. behind the meter peak shaving), and emergency power. The on-site generator can be diesel or natural-gas fired and will operate either: (i) in parallel with the distribution grid and require emissions controls and protections or (ii) during an emergency only when the distribution grid is unavailable for extended periods (i.e. in an islanded configuration). On-site generation can address extended outages, but due to limited generator response and protection settings, does not generally address momentary interruptions or large voltage sags. As such, reliance on this solution generally involves a "bump" in supply until the generator can re-supply the load.

Further, the use of diesel or natural-gas fired generation will lead to an increase in local air/noise emissions. Cost for on-site generation (excluding cogeneration applications) is estimated at $10 million for a 10 MW facility, including interconnection and maintenance costs over the service life of the asset.

The customers driving the proposed Customer-Specific ESS projects have rejected this option.

2. Option 2: Conventional Wires Options

Conventional wires options can include new feeders, feeder rebuilds, placing lines underground, upgrading stations and building new stations. At a feeder level, a traditional approach is to establish regulated zones on feeders using capacitor banks and reactive power compensators (i.e. regulators). Additionally, under load tap changers are often used to increase and decrease line voltage in response to changes in line loading. These traditional approaches to regulation can solve certain issues associated with coarse power quality; however, the dynamic nature of the load along a feeder makes it impossible to achieve adequate regulation in reaction to changes in load and high frequency transients. This technology is too slow to react to line disturbances, and voltage can be adjusted only in fixed increments due to the design of the tap changer.

Overhead feeders can be placed underground to substantially eliminate momentary interruptions; however, the costs of such projects are in the order of millions of dollars and cannot be justified based on tree and animal contact avoidance alone. In cases where line disturbances are associated with other feeders on the common bus, more than one overhead feeder may need to be converted to underground. This scale of intervention is costly, takes a long time to build out, and is disruptive to the community.

Vegetation management practices, including aggressive cut backs, can reduce (not eliminate) tree contacts but must be balanced with City policy and community acceptance given the importance of Toronto's tree canopy. Additionally, animal guards have been applied to help reduce animal contacts and resulting feeder disturbances and outages. Different designs have been developed over many years to combat this problem with considerable success. However, it remains difficult to eliminate animal contact.

None of the conventional wires options provide comprehensive protection (i.e. against momentaries, voltage sags and extended outages) or demand management and cost control, which are all benefits associated with on-site ESS.

The customers driving the proposed Customer-Specific ESS projects have rejected this option.

3. Option 3: Conventional Power Electronics

The conventional power electronics option involves using regulating devices to mitigate voltage drops (e.g. falling to 50 percent of nominal value for under 10 seconds). Conventional solutions include STATCOM and SVC, which employ power electronics and capacitors to absorb or supply reactive energy in order to regulate voltage . Since capacitors can store a very limited amount of energy, STATCOMs and SVCs are not intended to function as energy sources for the purpose of supplying load. As a result, they provide limited benefit to customers. The differences between STATCOMs and SVCs include stability under varying voltage levels, response speed, and harmonic emissions.

The installed cost for conventional power electronics ranges between $10 million to $15 million for a 10 MW facility.

Due to their limited capabilities and benefits, the deployment of STATCOMs and SVCs is not recommended in this case. Additionally, customers driving the proposed Customer-Specific ESS projects have rejected this option.

4. Option 4: Do More and Accelerated Spend Options

Customer-Specific ESS is customer driven. Spending more or spending more quickly than forecasted is a risk associated with any customer driven program. The proposed option is based on negotiation with several customers planning energy storage in the service area. This program can be expanded if necessary given the projects are funded with customer contributions.

5. Option 5 (Selected Option): Proposed Solution

Customer-Specific ESS provides Toronto Hydro with a more focused option for improving power quality and providing customers with emergency capacity. This non-wires solution can offer a lower cost alternative to conventional distribution infrastructure investment, can be executed quickly, and is less disruptive to the community than traditional wires solutions. Additionally, it can also provide additional system and customer benefits that are not available from conventional wires options or conventional on-site generation, including future control and capacity opportunities and deferral of traditional generation, transmission, and distribution upgrades.

Since the individual customers who benefit from these projects fund 100 percent of the cost through capital contributions, the size of the Customer-Specific ESS segment can scale-up relatively easily based on customer interest. That is, the proposed option also encompasses "Do More" and "Accelerated Spend" options.

E7.2.5 Execution Risks and Mitigation

Project execution risks may impact project design, project siting, approvals, construction, project schedule and commissioning.

Compared to traditional technologies, there are many fewer technical resources in the sector with knowledge on ESS are available to design, install and commission the systems, which can lead to a delay in program implementation and increased costs. Toronto Hydro will manage this risk by researching and applying relevant experiences from other jurisdictions and investing in training and staff development for engineering and skilled trades.

Project siting and approvals risk is generally limited because ESS involves electronics technology with minimal air/noise emissions and is therefore subject to standard building permit approvals (without extensive environmental assessment requirements) on utility or customer-hosted sites.

Construction cost variance is mitigated through a competitive procurement system for ESS projects and standard contract provisions which provide fixed price responsibility and liquidated damages for non-performance. Based on market projections, battery ESS technology will mature and prices fall providing some protection against year-over-year inflation and a degree of budget contingency. Battery costs represent approximately half the cost of ESS, while converters, switchgear, transformation, controls, conditioning, civil work and enclosures make up the balance. Costs for ESS continue to decline with average battery prices moving from US$300/kWh in 2015 to an expected US$110/kWh in 2024.[15] As such, over the 2020-2024 period, the cost/benefit value proposition of ESS will likely continue to improve, thereby facilitating increased use of this solution to address customer needs.

[15] Lithium-ion Battery Costs and Market, Bloomberg New Energy Finance, July 5, 2017.

Project schedule risk can be effectively managed by dedicated project teams that provide short-interval control and regular coordination between the utility and customers. Toronto Hydro will dedicate its efforts in the first year of the program to selecting suitable locations and obtaining lease/easement agreements for all feeder projects. Labour availability and project prioritization with other capital project and planned maintenance work will be managed to implement this program on-schedule.

ESS projects are complex due to bi-directional power flow and interface protections between project locations and their associated feeder/station supply point. Commissioning risk can be mitigated by using a standard requirements matrix and site acceptance testing protocol. Further, in-depth training in advance of actual field work is planned for crew members and operations staff who will take part in ESS installation and commissioning.

E7.2.6 Appendix A: EPRI Benefits of Energy Storage

Energy storage can provide a rich spectrum of economic, reliability, and environmental benefits to the electric grid, to electricity end-users and to society as a whole. Electric Power Research Institute (EPRI) studied benefits of energy storage using in their 2010 report: ***Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects***.

Table 21: EPRI Smart Grid Technology Benefits: Energy Storage

Benefit Category	Benefit Sub-Category	Benefit
Economic	*Improved Asset Utilization*	1) Optimized Generator Operation
		2) Deferred Generation Capacity Investments
		3) Reduced Ancillary Service Cost
		4) Reduced Congestion Cost
	T&D Capital Savings	5) Deferred Transmission Capacity Investments
		6) Deferred Distribution Capacity Investments
	Energy Efficiency	7) Reduced Electricity Losses
	Electricity Cost Savings	8) Reduced Electricity Costs
Reliability	*Power Interruptions*	9) Reduced Sustained Outages
	Power Quality	10) Reduced Momentary Outages
		11) Reduced Sags and Swells
Environmental	*Air Emissions*	12) Reduced CO_2 Emissions
		13) Reduced SOx, NOx, and PM-10 Emissions

1) **Optimized Generator Operation:** The ability to respond to changes in load would enable grid operators to dispatch a more efficient mix of generation that could be optimized to reduce cost, including the cost associated with polluting emissions. Electricity storage can be used to absorb generator output as electrical load decreases, allowing the generators to remain in their optimum operating zone. The stored electricity could then be used later so that dispatching additional, less efficient generation could be avoided. The storage can have the effect of smoothing the load curve that the generation fleet must meet. This benefit includes two components: (1) avoided generator start-up costs and (2) improved performance due to improved heat rate efficiency and load shaving.

2) **Deferred Generation Capacity Investments:** Electricity storage can be used to reduce the amount of central station generation required during peak times. This would tend to improve the overall load profile and allow a more efficient mix of generation resources to be dispatched. This can save utilities money on their generation costs.
3) **Reduced Ancillary Services Cost:** Ancillary services including spinning reserve and frequency regulation can be provided by energy storage resources. The reserve margin is a required capacity above the peak demand that must be available and is typically +15 percent of peak demand. If peak demand is reduced, reserve margin would be reduced.
4) **Reduced Congestion Cost:** Distributed energy resources provide energy closer to the end use, so less electricity must be passed through the transmission and distribution lines, which reduces congestion.
5) **Deferred Transmission Capacity Investments:** Utilities build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Providing stored energy capacity closer to the load reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. This may be particularly effective during peak load periods.
6) **Deferred Distribution Capacity Investments:** Electricity storage can also be used to relieve load on overloaded stations and feeders, potentially extending the time before upgrades or additions are required.
7) **Reduced Electricity Losses:** By managing peak feeder loads with electricity storage, peak feeder losses, which are higher than at non-peak times, would be reduced.
8) **Reduced Electricity Costs:** Electricity storage can be used to reduce the cost of electricity, particularly during times when the price of "grid power" is very high. A consumer or the owner of an enabled DER realizes savings on his electricity bill.
9) **Reduced Sustained Outages:** Electricity storage can be used as a backup power supply for one or more customers until normal electric service can be restored. However, the backup would only be possible for a limited time (a few hours) depending on the amount of energy stored.
10) **Reduced Momentary Outages:** When combined with the necessary control system, energy storage could act like an uninterruptible power supply (“UPS”), supporting end use load during a momentary outage.

11) **Reduced Sags and Swells**: The same UPS capability could be used to enable load to ride through voltage sags and swells.
12) **Reduced CO_2 Emissions**: Electricity storage can reduce electricity peak demand. This translates into a reduction in CO_2 emissions produced by fossil-based electricity generators. However, since electricity storage has an inherent inefficiency associated with it, electricity storage could increase overall CO_2 emissions if fossil fuel generators are used for charging.
13) **Reduced SOx, NOx, and PM-10 Emissions**: Electricity storage can reduce electricity peak demand. This translates into a reduction in polluting emissions produced by fossil-based electricity generators. However, since electricity storage has an inherent inefficiency associated with it, electricity storage could increase overall emissions if fossil fuel generators are used for charging.

E7.3 Network Condition Monitoring and Control

E7.3.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): -	**2020-2024 Cost ($M)**: 63.0
Segments: Network Condition Monitoring and Control	
Trigger Driver: Reliability	
Outcomes: Customer Service, Reliability, Environment, Safety, Financial	

The Network Condition Monitoring and Control program is designed to introduce real-time, Supervisory Control and Data Acquisition ("SCADA")-enabled monitoring and control to Toronto Hydro's low voltage secondary network distribution system. The network system supplies 13 percent of the peak load in downtown Toronto, including key customers like banks and hospitals that are highly sensitive to service interruptions. SCADA-enabled monitoring and control will benefit these customers by introducing remote operating and switching capabilities that are already utilized in many other parts of the system. It will also introduce real-time monitoring capabilities with respect to the following types of operating parameters:

- Air temperature and water level in the vault;
- Oil level, oil temperature and tank pressure of the network transformer; and
- Current, voltage, open/closed status and water level of the network protector, which is essential to the automatic transfer capabilities that allow the reliability benefits of the network design to materialize.

These capabilities will support continuous improvement on a number of key outcomes for downtown customers, the public, and the environment. More specifically, such capabilities include: remote identification of active failure risks (e.g. floods) and prevention of subsequent outages; the ability to sustain service for substantially more customers during multiple contingency events; early identification of potential safety risks (e.g. vault fires); early identification of oil leaks; and improved loading data accuracy, which will help Toronto Hydro to connect more customers to the network system in a more timely and cost effective manner overall. Finally, Toronto Hydro expects remote sensing capabilities to result in approximately $0.1 million in annual system operation and maintenance savings by 2024, as the need for certain types of inspections will be eliminated.

The low voltage network distribution system has historically been Toronto Hydro's most reliable system. Toronto Hydro recently began deploying new, higher voltage network units to better accommodate growth in the core and help reverse a gradual decline in the number of customers connected to the network. At the same time, the existing network is aging as vaults experience floods and transformers corrode and leak oil, as evidenced by the hundreds of deficiencies observed in recent years. Several catastrophic and highly disruptive failures affecting customers have also occurred in recent years. Given these constraints and pressures, Toronto Hydro is prioritizing the Network Condition Monitoring and Control program as a means of improving reliability, system resiliency, and efficiency of operations on the network. The utility plans to invest $63 million between 2020 and 2024 with the objective of installing monitoring equipment and fibre optic cable in approximately 90 percent of the 1,055 network vaults by the end of 2024. This will support the outcomes summarized above and described in more detail below.

E7.3.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives (e.g. OEB's ESQR targets, which require new services to be connected on time 90 percent of the time) by enabling more efficient connections through use of live loading data for power flow modeling.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Reducing flooding-related equipment damage; ○ Enabling the early detection of conditions that can cause vault fires to improve response time and mitigate damage; ○ Providing real-time loading data and remote switching capabilities to allow controllers to drop approximately one-third fewer customers from the network during multiple contingency events.
Environment	• Contributes to Toronto Hydro's environmental objectives by reducing oil leaks through monitoring of transformer oil levels.
Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency measure and safety objectives by enabling early warning of potential risks associated with vault loading, flooding and fire.

Financial	• Contributes to Toronto Hydro's financial objectives by eliminating the need for crews to perform inspections and obtain summer load readings.

E7.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Reliability
Secondary Driver(s)	Safety, Failure Risk, System Efficiency

The Network Condition Monitoring and Control program aims to improve the reliability of Toronto Hydro's low voltage secondary network system by introducing real-time SCADA-enabled monitoring and control. The installed equipment and fibre optic communication cables will provide live condition and loading data and remote control capabilities that will enable Toronto Hydro to respond proactively and more effectively to emerging hazards and multiple contingency events, leading to fewer and shorter interruptions for sensitive downtown customers.

Toronto Hydro's network distribution system peak load is about 13 percent of the total downtown load (e.g. 230 MVA of 1800 MVA in total). Although network distribution provides the most reliable service offered by Toronto Hydro, it has not been available for some important customer classes. Typically, larger downtown customers could only be supplied with a dual radial connection. However, as of 2017, a 600V secondary network option became available.[1] This means larger customers, such as condos and large commercial and mixed-use buildings, can choose a more reliable network service. With this new option, Toronto Hydro is expecting to reverse a recent decline in network system load. For example, network load experienced a steady decline over the 10-year period between 2006 and 2015 from 308 MVA to 234 MVA. However, the existing network system is aging and susceptible to flooding and oil leaks, resulting in several catastrophic failures in recent years. In response, Toronto Hydro plans to improve the network system's resiliency, reliability and operation efficiency through SCADA-enabled monitoring and control.

[1] With the older, lower rated equipment, only buildings up to about 25 stories could be connected to the network system due to excessive voltage drop for taller buildings. The 600 V option enables connection of buildings up to at least 70 stories.

The components required to enable monitoring and control of a network vault and unit are depicted in Figure 1. Vault sensors include a water level sensor and a vault temperature sensor, which are connected directly to the communication box. Transformer mounted sensors include oil temperature, oil level and tank pressure. Protector monitoring and control are all enabled through a special communication-ready network protector relay mounted inside the network protector. [2] Network units manufactured after 2010 have the required sensors built-in, while older units need retrofit packages to be installed.

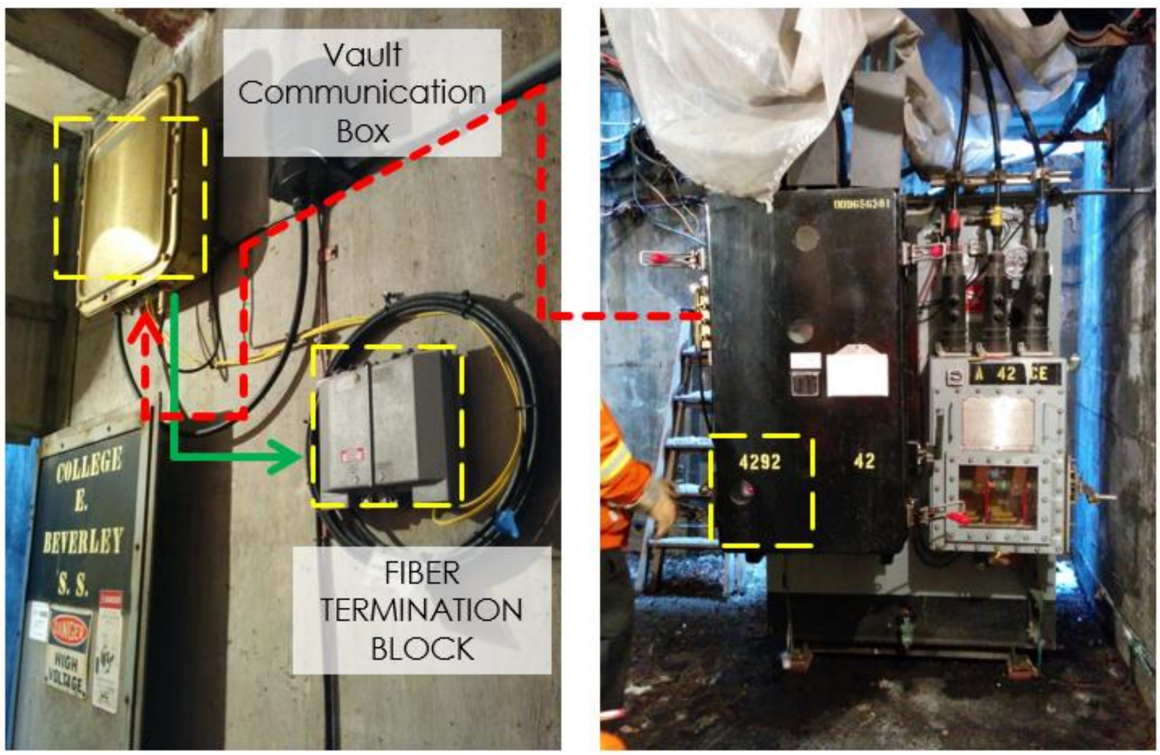


Figure 1: Vault Layout with Network Condition Monitoring and Control Equipment Installed

Once work inside the vault is completed, Toronto Hydro can monitor and control the automated vaults through a SCADA screen from the control room, an example of which is shown in Figure 2 below.

[2] The network protector automatically connects and disconnects individual transformers from the secondary grid to compensate for primary feeder switching and equipment failures.

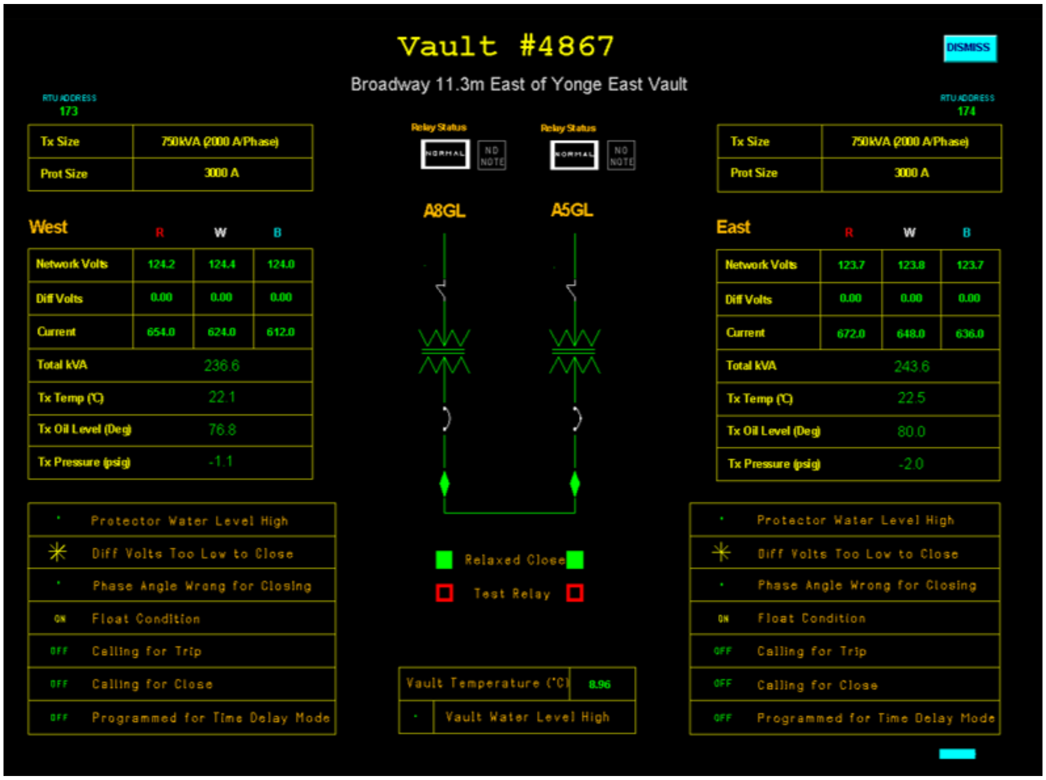


Figure 2: SCADA Screen for a Vault with Network Condition Monitoring and Control

E7.3.3.1 Network Vault Condition Monitoring

The Network Condition Monitoring and Control program will provide live condition data of the vault and network units. This will give the Control Room access to important information on developing hazardous conditions such as flooding, fire, and oil leaks, allowing proactive measures to be taken to prevent equipment failure and mitigate safety and environmental risks. Such data includes vault temperature and water level, network transformer operating temperature, oil level and tank pressure, and the presence of water inside network protectors.

The proposed use of water level sensors would mitigate the risk of equipment damage and reduce customer service interruptions due to vault flooding. In 2018, there are approximately 750 protectors that are not designed to operate when submerged under water. From 2015 to 2017, inspections found 76 incidents of protector internal water stains and 370 incidents of vault flooding. It is estimated that half of these occurrences can be proactively addressed through the installation of flood level sensor alarms by 2024. Once installed (approximately 30 cm above the vault floor), water level sensors would trigger alarms in the Control Room when rising water reaches the sensor.

Toronto Hydro will then dispatch a crew to address the flooding prior to water levels reaching a point where equipment is damaged or at risk of failure.

Monitoring of the network system will also enable Toronto Hydro to detect fires earlier, improving response time and mitigating any damage to equipment and safety risks that may result. If a fire occurs, the Control Room will be informed and can remotely operate vault equipment to prevent catastrophic failures. This would help lessen the impact to the customers directly connected to a given vault, as well as minimize potential widespread network outages that impact all customers connected to the network grid.

Oil leaks are another concern which can be addressed through network vault monitoring. If a serious transformer oil leak is not promptly identified, transformer failure could occur shortly after the oil level drops below the windings or upper cooling tubes. This could result in a catastrophic transformer fire causing widespread and prolonged customer interruptions. In addition, leaking oil within a vault may enter the vault drainage system and discharge into the environment. Figure 3 shows the volume distribution of 223 network transformer oil leaks identified by Toronto Hydro from 2015 to 2017.

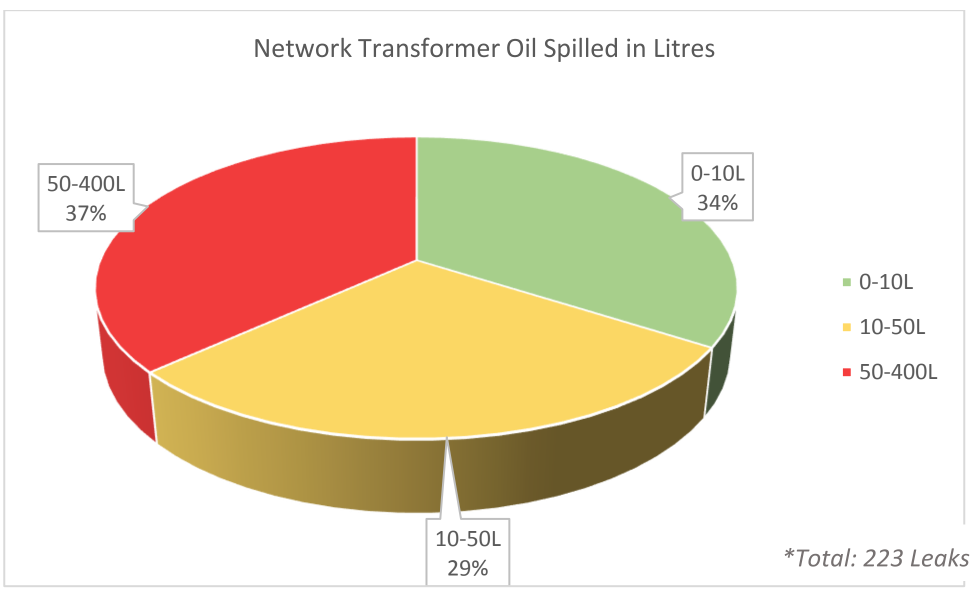


Figure 3: Network Transformer Oil Leaks 2015-2017

The proposed condition monitoring equipment will alert Toronto Hydro to a leaking transformer, so that crews can be dispatched to contain the leak and minimize environmental damage until the unit can be replaced. Toronto Hydro expects this measure to limit the larger leaks to 50 litres, reducing the volume of the largest spills (which make up over a third of those reported in 2015-2017) by 95 litres. Oil level monitoring data will also support the accurate reporting of oil quantities to the Ministry of the Environment and Climate Change and the City if a spill occurs.

E7.3.3.2 Network Unit Control and Loading Data

The monitoring and control equipment also provides remote control capabilities and loading data required for emergency operations as well as normal analysis and planning. When live condition data is not available, it is acquired through estimates or field inspections, which are both less accurate and more resource intensive. Real-time loading data will allow controllers to more effectively respond to multiple contingency events and emergency situations resulting in fewer and shorter customer interruptions. Remote monitoring and control would also reduce the need for crews to visit vaults. This benefits customers by both expediting service restoration during network emergencies, as well as reducing costs associated with normal network system operations. Features that will provide these benefits include:

- monitoring of operating voltages and currents;
- monitoring of the open/closed status of network protectors;
- ability to remotely open or close protectors;
- automatic reporting of conditions preventing equipment from automatically operating as desired (e.g. voltage too low to reclose); and
- ability to temporarily alter equipment settings to facilitate automatic operation (e.g. “relaxed close”) that would otherwise not occur.

The loads for the low voltage secondary networks targeted for Network Condition Monitoring and Control in 2020-2024 are shown in Table 4 below. Through this program, Toronto Hydro expects to avoid dropping one third of the total network load (which would otherwise have to be dropped in multiple contingency events). Approximately once every three years, a multiple contingency event results in a forced widespread outage. These networks are designed to handle first contingency (N-1) outages at both the feeder and network unit levels without causing customer interruptions. However, second contingency (N-2) or higher events require network analysis to determine whether customer loads can be sustained or must be dropped in order to avoid excessive equipment loading levels. In the absence of live loading data, conservative load estimates are made for this analysis. Toronto Hydro derives these estimates using loading data from summer inspections, which may not be accurate due to variances in season, ambient temperature, time of day, and day of the week. In contrast, accurate real-time loading information will allow the Control Room to operate network equipment according to the actual limits during multiple contingency events.

Table 4: Potential Customer Load Saved From Monitoring and Control

Network	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Automation Year	Expected Load Saved During Multiple Contingency Events (MVA)
GD Phase 1	49	11.6	2019	3.9
GD Phase 2		17.4	2020	5.8
CS-West Phase 1	45	11	2020	3.7
CS-West Phase 2		11	2022	3.7
Bridgman Total	29.2	14.6	2022	4.9
Highlevel Total	112	56	2023	18.7
Glengrove Total	28	14	2024	4.7
Duplex Total	69.6	34.8	2024	11.6
Gerrard Total	12	6	2023	2.0
Dufferin Phase 1	5.5	4	2023	1.3
Dufferin Phase 2	15.7	12	2024	4.0
Wiltshire Total	1	1	2024	0.3
Leaside Total	3	2	2024	0.7
Main Total	9	7	2024	2.3
Carlaw Total	9	7	2024	2.3
Strachan Total	9	7	2024	2.3

Table 4 also shows the potential customer load that may be saved for each of these networks during a multiple contingency event. These savings are estimated based on the avoidance of dropping one third of the network load. The targeted networks in Table 4 represent about 72 percent of total network system load based on non-concurrent peaks. On average, multiple contingency events occur once every three years.

In addition to the aforementioned benefits, the availability of live loading data has other benefits, including customer service improvement and operating cost avoidance, as discussed below.

Deployment of the Network Condition Monitoring and Control program will provide more accurate peak readings of Toronto Hydro's network assets than can be achieved through summer vault inspections. From a planning perspective, engineers will be able to model the various parts of the system with greater accuracy and plan based on more accurate power flow models. Network customer requests can be challenging to handle, and accurate power flow models are essential for efficiently connecting customers. More efficient connections will result in lower-cost and faster customer connection, contributing to the utility's compliance with OEB-prescribed objective to connect new services on time 90 percent of the time.

Regarding operating cost avoidance, Toronto Hydro conducts three inspections per year of all network vaults in the system, one of which is also used to collect summer peak vault loading data. When a network vault is automated, the summer peak reading inspection can be eliminated as peak loading data can be extracted from the SCADA system instead. Figure 4 shows the annual operating costs that may be avoided as this program progresses and additional vaults are automated each year

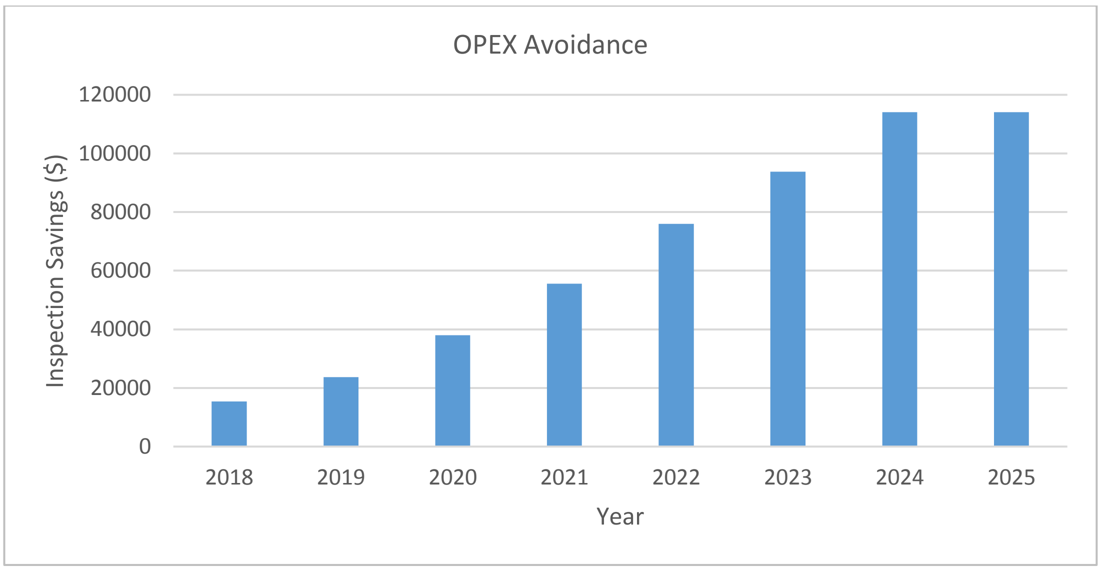


Figure 4: Expected Operating Expenditure Avoidance by Year

E7.3.4 Expenditure Plan

The Network Condition Monitoring and Control program aims to improve issues related to reliability, safety, failure risk, and system efficiency primarily by investing in monitoring and control equipment installations inside network vaults, as well as a fibre optic communications backbone installed under city streets. Table 5 below depicts the forecast (2020-2024) spending for this program.

Table 5: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Network Condition Monitoring and Control	-	-	-	-	-	7.6	10.2	12.6	15.3	17.4

There are no historical (2015-2017) or bridge (2018-2019) expenditures associated with this program. Toronto Hydro funded the work done in 2015-2019 (averaging $2.2 million per year) as part of the Network Unit Renewal Program (now a segment within Network System Renewal program)[3] as there were synergies between the types of work undertaken in that program and this one.

Table 6 summarizes the 2015-2019 projects and their estimated costs. Two stations, Windsor and Cecil, which supply the Spadina network area south of College were chosen as the pilots for this program. By the end of 2019, Toronto Hydro expects to have commissioned 204 of the vaults for which necessary equipment and fibre will have been installed. Completion of this work will result in the first substantial addition to Toronto Hydro's facilities to remotely monitor and control its network system.

Table 6: 2015-2019 Projects.

Network	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Automation Year	Actual or Estimated Costs ($Millions)
WR-West Phase 1	55	12.5	2017	3.4
WR-West Phase 2		12.5	2018	1.1
A-North Phase 1	44	13.5	2018	2.0
A-North Phase 2		13.5	2019	3.0
CE-South Phase 1	32	6.5	2017	2.3
CE-South Phase 2		6.5	2018	

For 2020-2024, Toronto Hydro plans to spend $63 million to automate another 13 networks by completing the fibre and equipment installation and commissioning for 750 vaults. Table 7 provides the proposed timing by network.

[3] See: Exhibit 2B Section E6.4.

Table 7: 2020-2024 Projects.

Network	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Automation Year
GD Phase 1	49	11.6	2019
GD Phase 2		17.4	2020
CS-West Phase 1	45	11	2021
CS-West Phase 2		11	2021
Bridgman Total	29.2	14.6	2022
Highlevel Total	112	56	2022
Duplex Total	69.6	34.8	2023
Gerrard Total	12	6	2023
Dufferin Phase 1	5.5	4	2023
Dufferin Phase 2	15.7	12	2024
Glengrove Total	28	14	2024
Wiltshire Total	1	1	2024
Strachan Total	9	7	2024
Carlaw Total	9	7	2024
Main Total	9	7	2024
Leaside Total	3	2	2024

The planned pacing of execution is the fastest practical rate that Toronto Hydro is realistically able to achieve given available resources. By enabling monitoring and control of approximately 90 percent of the network system by 2024, this program will improve reliability for downtown customers, saving them from multiple contingency events, and contributes to the utility's system reliability objectives. Customers will also benefit from faster and less expensive connections and reduced safety and environmental risks.

The prioritization and scheduling of projects in this program are based on the proposed fiber optic installation plan shown in Figure 5. Installation of the necessary fiber backbone is a prerequisite for testing and commissioning monitoring and control equipment installed in individual vaults. Therefore, equipment installation in vaults is planned for the year following the completion of fiber installation. In addition, network units installed after 2010, including those to be replaced through the Network System Renewal program, will be equipped with the necessary relays and sensors required for monitoring and control. Network units installed prior to 2010 need to be retrofitted, which is a need that is accounted for during project prioritization.

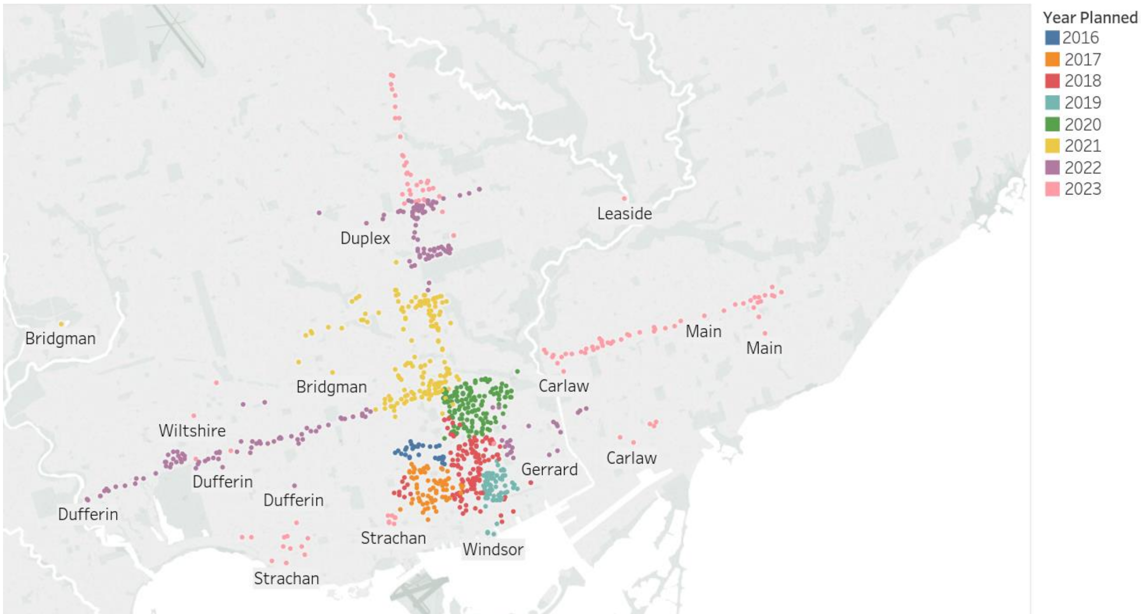


Figure 5: Fibre Optic Cable Deployment by Year and Station

Toronto Hydro chose Windsor and Cecil as the first networks to be automated for two reasons. First, their mutual proximity permits the same fibre backbone to be used for both networks. Second, these are particularly important networks based on loading and critical customers. Next, Toronto Hydro plans to branch out to other downtown stations, starting with Terauley and taking into account the City's King Street Pilot Project and related road moratoriums affecting execution at other adjacent stations. During the 2020-2024 period, Toronto Hydro plans to complete automation of the remaining portions of the downtown core prior to proceeding with the more distant network areas.

E7.3.5 Options Analysis

E7.3.5.1 Option 1: No Automation at the Remaining Network System Vaults

Under this option, the network system would remain unmonitored. Oil leaks, vault flooding, vault fires, protector failures, and protector flooding would continue to be addressed on a reactive basis, leading to potential outages for customers and potentially serious environmental consequences. Replacement units will continue to be provided with sensors; however, SCADA connection will not be implemented. With no live loading data available, Toronto Hydro will continue to rely on less accurate loading information acquired through estimates or field inspections for the purposes of planning for and responding to multiple contingency events. Therefore, this program is not recommended.

E7.3.5.2 Option 2: Network Condition Monitoring and Control at Reduced Rate

Automation of the seven of the 13 remaining networks (approximately 70 percent of network vaults) over 2020-2024 would result in reliability improvements for customers on those networks by 2024. Although this would cost approximately $20 million less than the proposed plan, the benefits of monitoring and control would be delayed to beyond 2024 for the remaining six networks (approximately 20 percent of network vaults). The Network Condition Monitoring and Control program provides good value for the money spent and not proceeding with monitoring and control of all of the remaining networks does not align with customer engagement results, which favour faster implementation of monitoring and control on the network system.[4] This option is therefore not recommended.

E7.3.5.3 Option 3 (Selected Option): Condition Monitoring and Control of 13 Networks

Automation of the 13 proposed networks means Toronto Hydro will have live access to the following for all networks in the secondary network system: vault temperature, vault water level, network unit loading, transformer oil level, transformer top oil temperature, transformer tank pressure, protector status, protector water level, and protector remote control. This option is preferred as it is expected to lead to reliability and safety improvements, including fewer and shorter customer interruptions, quicker responses to emerging hazardous situations, reduced environmental impacts, and reductions in reactive capital and operating costs. These benefits result from the ability to identify developing problems before equipment failure occurs, improved ability to operate networks under multiple contingency events, as well the ability to remotely monitor and operate equipment resulting in quicker and more cost-effective responses. This option is also consistent with customer engagement results prioritizing monitoring and control of the network system.

[4] Exhibit 1B, Tab 4, Schedule 1, Appendix A,

E7.3.6 Execution Risks & Mitigation

E7.3.6.1 Fibre Installation

Fibre optic cable is the first asset that must be installed as part of the Network Condition Monitoring and Control program. Installation of fibre under city streets poses a number of risks that may cause program delays and increase costs, including:

- Lack of existing duct capacity for the fibre optic cable;
- Road construction moratoriums and road work restrictions;
- Construction blocking access to cable chambers and vaults; and
- Leaking feeders posing hazards that prevent workers from entering cable chambers and vaults.

If a problem is only identified once construction begins, it results in reactive work, increased cost, and program delays. Toronto Hydro mitigates these risks by performing detailed field inspections during the design phase of the program and then designing solutions that avoid problem locations altogether. Alternatively, the utility can plan ahead for necessary construction work to avoid impacting the program's critical path timeline.

E7.3.6.2 Vault Equipment Installation

Certain risks can delay the installation of equipment inside network vaults and increase costs, including:

- Flooded vaults;
- Lack of suitable available space to install equipment; and
- Existing primary feeder installation interfering with the installation of transformer sensors.

Toronto Hydro mitigates all of these risks by performing a detailed field inspection during the design phase. The utility can complete corrective work on flooded vaults prior to starting construction work for this program. To address a lack of suitable available space to install equipment, such issues will be proactively identified, and the relevant project will be designed to include the necessary equipment relocation work and scheduled to avoid impacting the program's critical path timeline. Where existing primary feeder installations interfere with installation of a particular transformer sensor, Toronto Hydro may omit the sensor and adjust the Control Room SCADA display to compensate.

E7.4 Stations Expansion

E7.4.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 180.1	**2020-2024 Cost ($M):** 136.4
Segments: Copeland TS – Phase 2, Hydro One Contributions, Local Demand Response ("DR")	
Trigger Driver: Capacity Constraints	
Outcomes: Customer Service, Reliability, Public Policy, Environment, Financial	

Toronto Hydro's Stations Expansion program (the "Program") addresses medium- to long-term system capacity needs. The Program is driven by capacity constraints on the distribution system. Increased and continued densification and population growth are driving the need to relieve the loading on the distribution system and create additional capacity. If not dealt with proactively, this will impact Toronto Hydro's ability to connect customers to its distribution system. The primary focus of the work planned in the 2020-2024 period is on the downtown and south-west area of the system, where growth continues to be concentrated.

The Stations Expansion program consists of the three segments summarized below, and is a continuation of the expansion activities described in Toronto Hydro's 2015-2019 Distribution System Plan.[1]

- **Copeland TS – Phase 2**: this segment will expand the capacity of Toronto Hydro's Copeland Transformer Station ("TS"), located in the centre of Toronto's financial district. The project will provide additional capacity of 144 MVA. The additional capacity is needed to support forecasted growth and development in the City's Central Waterfront area while maintaining and enhancing system reliability and resiliency for outage-sensitive customers in the downtown core. Toronto Hydro's 2015-2019 Distribution System Plan included a high-level proposal to begin work on the Copeland TS – Phase 2 project in 2019. Toronto Hydro developed a more detailed plan in 2016 which included advancing some work into the 2017-2019 timeframe to account for expected project lead times. In total, Toronto Hydro expects the Copeland TS – Phase 2 project will cost an estimated $89 million, with $79 million of those expenditures occurring in the 2020-2024 period. The estimated in-service date is 2024.

[1] EB-2014-0116, Exhibit 2B, Section E7.9

- **Hydro One Contributions:** this segment covers Toronto Hydro's forecasted capital contributions to Hydro One for work related to:
    - Expansion of Horner TS, which will provide an additional capacity of 192 MVA in South-West Toronto to enable medium-to-long term load and customer growth as anticipated based on the Toronto Integrated Regional Resource Plan ("IRRP") process;
    - Cost-effective capacity upgrades of end-of-life ("EOL"), Hydro One-owned power transformers as anticipated based on the IRRP process;

  Toronto Hydro plans to invest an estimated $53 million in this segment in the 2020-2024 period compared to a forecasted $99 million in 2015-2019.
- **Local DR:** this segment includes cost-effective non-wires investments to manage local capacity constraints while deferring larger, traditional wires investments. Toronto Hydro is proposing targeted DR strategies to reduce peak demand by approximately 10 MW, supporting the deferral of approximately $135 million in capital investment at Cecil TS and Basin TS for 5 to 6 years. The capital budget for this Program in the 2020-2024 period consists of an estimated $4.6 million in 2023-2024 for a battery storage project in the Basin TS area. Under the Asset and Program Management program[2], Toronto Hydro plans to allocate operational expenditures associated with this segment.

The investments summarized above and in the remainder of this narrative are informed by, and fully aligned with, IRRP activities conducted in coordination with the IESO and Hydro One. The most recent planning document from this process is the Needs Assessment Report for the Toronto Region ("Needs Assessment"). A high level reconciliation of the Needs Assessment with Toronto Hydro's Stations Expansion program is found in Section E7.4.7 of this narrative.

The Stations Expansion program also responds to the need for maintained system reliability and increased grid resiliency to support Ontario public policy drivers. To this end, the Program focuses on Toronto Hydro's broad strategy of grid modernization within the context of an aging, dense urban infrastructure, aiming to support customers and load growth and both mitigating and adapting to climate change through grid resiliency and innovation.

[2] Exhibit 4A, Tab 2, Schedule 9, Section 7

In total, Toronto Hydro plans to invest an estimated $136.4 million in stations-level capacity expansion in the 2020-2024 timeframe compared to a forecasted $180.1 million in the 2015-2019 timeframe. The utility expects to add or free-up over 400 MVA in capacity on the system as a result.

E7.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Reducing the number of stations unable to connect new large customers in the downtown and Horseshoe areas by investing in 415 MVA in additional supply capacity by 2025; ○ Increasing supply capacity using DR measures; and ○ Alleviating feeder position limitations that prevent customer connections.
Reliability	• Contributes to maintaining Toronto Hydro's System Capacity Measure and system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Providing redundancy and operational flexibility by upgrading capacity at supply points to keep the number of highly loaded stations (with loads > 90 percent capacity) at a minimum for the downtown and Horseshoe areas; and ○ Managing peak loads and alleviating capacity constraints to reduce the risk of outages by maximizing the use of existing capacity through targeted DR initiatives, • Investing in climate-resilient station infrastructure and equipment, in particular at Copeland TS which has flood defenses, seismic protections (i.e. earthquake resistant), and is protected from exposure to storms.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Supporting the IRRP and the Ontario Long-Term Energy Plan ("LTEP") by meeting local needs through a mix of traditional infrastructure, energy storage, conservation and DR; ○ Enabling electrification by investing in additional capacity and operational flexibility; ○ Supporting Ontario's Conservation First Framework by investing in non-wires alternatives.

Environment	• Contributes to Toronto Hydro's environmental objectives by investing in capacity to support operational flexibility, enable electrification, and support the proliferation of distributed energy resources (DERs).
Financial	• Contributes to Toronto Hydro's financial objectives by deferring approximately $135 million in capital investment through the use of targeted DR strategies.

E7.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Capacity Constraints
Secondary Driver(s)	Reliability

The Stations Expansion program is driven by capacity constraints on the distribution system. Increased and continued densification and population growth are driving the need to relieve loading on the distribution system and create additional capacity. These conditions are only expected to intensify beyond 2024 as supported by the City of Toronto's long-term Precinct Plans[3] for both the downtown and the Horseshoe areas and by Toronto Hydro's 10-Year Station Load forecast (see Section D of the DSP). Toronto Hydro anticipates that the significant redevelopment and load growth associated with planned projects[3] in the downtown and central waterfront will result in 208 MVA of incremental load in the City's core over the 2020-2024 period or shortly thereafter. Similar to the downtown region, the Horseshoe area continues to experience concentrated load growth. The City of Toronto's "Precinct Plans" [4] for the region, including the South-West Toronto area, shows a load growth of 252 MVA, which includes all planned projects forecasted to materialize over the 2020-2024 period, or shortly thereafter. The Load Demand program[5] includes a more detailed discussion of the proposed Precinct Plans and how they factor into Toronto Hydro's capacity investment plans. Continued densification and population growth are expected to continue driving up system loading up to and beyond 2024. If not dealt with proactively, this trend will impact Toronto Hydro's ability to connect customers to the distribution system.

[3] City of Toronto, *How Does The City Grow?* (April 2017), available <https://web.toronto.ca/wp-content/uploads/2017/08/9014-How-Does-the-City-Grow-April-2017.pdf>.
[4] *Supra* note 4.
[5] Exhibit 2B, Section E5.3.

Addressing capacity constraints in the downtown core is crucial as stations primarily serve institutional, commercial, and large residential condominium customers experiencing rapid, large-scale growth, including electric transportation infrastructure (e.g. subways, streetcars). Given the importance of loads associated with essential services in all these station areas, resiliency and reliability are extremely important. The work under this Program responds to the need for resiliency and reliability in these areas by relieving highly loaded station buses and ensuring availability of feeder positions to connect new customers. This provides an overall benefit to all ratepayers by connecting new customers to their optimal supply point within the station service area and thus maintaining low connection costs. Ensuring reliable and resilient power supplies to these essential services is important to all Toronto Hydro customers, regardless of their rate class.

Toronto Hydro's 10-year Station Load forecast predicts an increase in load which will reduce capacity availability at the following stations: Carlaw, Esplanade, Windsor, Terauley, Cecil, Manby, Richview, Fairbank, Strachan, Duplex, Charles, Basin, and Horner. Most of these stations are highly loaded and have either limited or no spare feeder positions available to enable load transfers or enable additional capacity. As a result, this reduces Toronto Hydro's ability to connect customers and large DERs to the distribution system efficiently within the station service areas.

The work planned under the Stations Expansion program is aligned with system needs identified in the Needs Assessment and in the Regional Infrastructure Plan ("RIP") report.[6] Table 4, Table 5, and Table 6 below highlight the needs and how they are addressed through the Stations Expansion program.

Table 4: New Needs

New Needs	NA Report Section	Stations Expansion Narrative
End-of-Life Assets	*7.1.1*	See *Table 8*.

Table 5: Needs Identified in Previous RIP

Needs Identified in Previous RIP	NA Report Section	RIP Report Section	Stations Expansion Narrative
South-West Toronto – Station Capacity	*7.2.1*	*7.2*	Addressed with Horner expansion in 2020-2024 Stations Expansion plan.

[6] Exhibit 2B, Section B, Appendix A, B, C, D, and E

Needs Identified in Previous RIP	NA Report Section	RIP Report Section	Stations Expansion Narrative
Downtown District – Station Capacity	*7.2.2*	*7.3*	Addressed with Copeland TS - Phase 2 expansion in 2020-2024 Stations Expansion plan.

Table 6: End-of-Life Assets – Metro Toronto Region

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Narrative
Charles TS T3/T4 Transformers	*2024-2025*	EOL Transformers and other HV equipment are identified at these stations for replacement with higher rated equipment, and are discussed further in Section 7.1.1.2 of NA report	Included in 2020-2024 Stations Expansion plan.
Duplex TS: T1/T2 Transformers	*2023-2024*		Included in 2020-2024 Stations Expansion plan.
John TS: T1, T2, T3, T4, T6 Transformers and 115 kV breakers	*2024-2025*	EOL Transformers and other HV equipment are identified at these stations where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.3 of NA report.	Included in 2020-2024 Stations Expansion plan.

The Stations Expansion program also responds to the need for maintained system reliability and increased grid resiliency to support public policy drivers. To this end, the Program focuses on Toronto Hydro's broad corporate strategy of grid modernization within the context of aging, dense urban infrastructure, supporting customers and load growth, and mitigating and adapting to climate change through grid resiliency and innovation.

The system needs are addressed through three segments: Copeland TS – Phase 2, Hydro One Contributions, and Local DR, as further discussed below.

E7.4.3.1 Copeland TS – Phase 2

The Copeland TS – Phase 2 is required to address capacity constraints in the downtown core, which continues to experience a high degree of densification and growth as identified in the most recent Regional Planning Needs Assessment report (i.e. IRRP, see Table 5 and Table 32). The Copeland TS - Phase 2 project is incremental to Phase 1 and is intended to make full use of potential capacity at the Copeland TS site. This will: (i) reduce loading on highly loaded buses at surrounding stations, allowing Toronto Hydro to continue to connect customers efficiently within the station service areas; and (ii) create 40 spare feeder positions, enabling load transfers through switching operations and new customer connections. Copeland TS - Phase 2 will provide an additional 144 MVA in the downtown area by 2024. This includes the installation of two additional 72 MVA busses, three gas insulated power transformers (two load-serving and one back-up) and the installation of a transfer bus.

Based on Toronto Hydro's most recent 10-year station load forecast[7] three downtown stations will require capacity relief in the 2020-2024 period: Windsor TS, Cecil TS, and Terauley TS. Figure 1 below provides a visual overview of these stations with an indication of when the busses are projected to require capacity relief. Typically, load relief on a 13.8 kV downtown station bus is required when the forecasted peak load of the bus reaches 95 percent of the bus firm capacity.

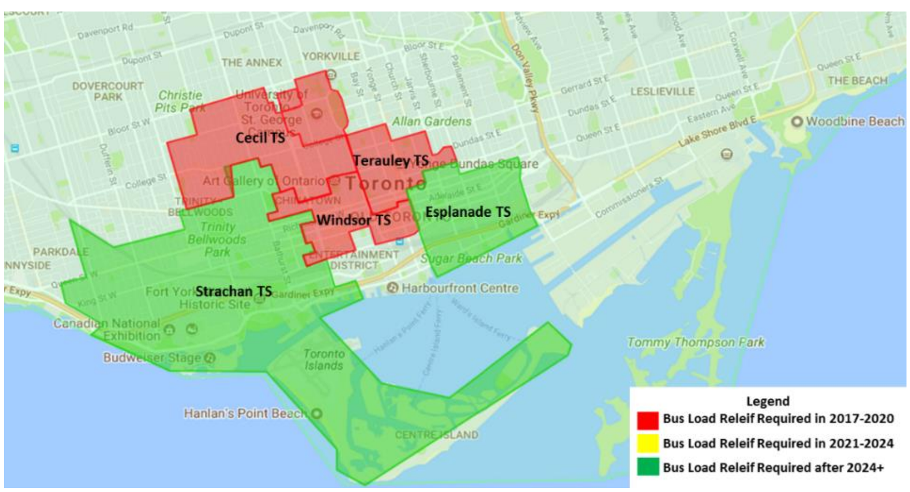


Figure 1: Geographical spread of Downtown Core Stations with a visual overview of bus load relief requirements

[7] Described in Exhibit 2B, Section D2.3 System Utilization

Continued investment in Copeland TS – Phase 2 will create forty spare feeder positions. Spare feeder positions are available unused feeders on a bus that enable: (i) the connection of new customers who cannot be connected via existing feeders and (ii) load transfers between and within stations. As seen in Table 7 below, Toronto Hydro faces a limited and decreasing number of spare feeder positions in the downtown area as evidenced by the fact that Cecil TS and Windsor TS do not have any spare positions remaining. This issue is of particular concern in the downtown core, because the design of the distribution system is such that feeder loading cannot be relieved through switching operations and can only be relieved through bus transfers (as described in more detail in Option 3 in section E7.4.5 Options Analysis).

Table 7: Downtown Core Station Load Profile (2017 vs. 2024)

Column A	Column B	Column C	Column D	Column E	Column F	Column H
Station	**Bus ID**	**2017 Bus Loading (%)**	**Spare Feeder Position – 2017**	**2020 Bus Loading (%)**	**2024 Bus Loading (%)**	**Potential # of CI[8] due to bus failure**
Cecil TS	*A1-2CE* [9]	57%	0	57%	60%	1
	A3-4CE	77%	0	79%	81%	2244
	A5-6CE	79%	0	99%	103%	3466
	A7-8CE	79%	0	83%	86%	4576
Esplanade TS	*A1-2X*	74%	0	67%	68%	758
	A1-2GD	90%	6	78%	81%	5095
	A3-4GD	83%	0	88%	90%	2898
Strachan TS	*A1-2T*	86%	0	89%	93%	5207
	A5-6T	65%	3	78%	80%	4165
	A7-8T	88%	1	88%	90%	7600
	A9-10T	78%	0	88%	90%	2160
Terauley TS	*A1-2A*	79%	1	91%	89%	772
	A3-4A	77%	1	98%	102%	982
	A5-6A	82%	7	90%	92%	1331
	A9-10A	70%	1	75%	68%	184

[8] "CI": Customers Interrupted
[9] Dedicated bus feeding University of Toronto

Column A	Column B	Column C	Column D	Column E	Column F	Column H
Station	**Bus ID**	**2017 Bus Loading (%)**	**Spare Feeder Position – 2017**	**2020 Bus Loading (%)**	**2024 Bus Loading (%)**	**Potential # of CI[8] due to bus failure**
Windsor TS	*A3-4WR* [10]	88%	0	90%	0%	5838
	A5-6WR [11]	90%	0	14%	93%	434
	A11-12WR	77%	0	77%	80%	21
	A13-14WR	95%	0	85%	88%	21
	A15-16WR	87%	0	88%	74%	468
	A17-18WR	88%	0	73%	76%	227
Copeland TS [12]	*A1-2CX*	81% [13]	1	81%	82%	--
	A3-4CX	63% [13]	3	0%	64%	--

Note: Red is ≥ 95 percent and orange is ≥ 90 percent.

Highly loaded station buses and a lack of spare feeder positions, as shown in Table 7, also limit contingency operation capabilities, making it more difficult for Toronto Hydro to restore service to customers in the event of an outage. When the supply at a station is lost, the impacted load needs to be re-distributed to nearby feeders to maintain service to at-risk customers. If the nearby feeders are also highly loaded or have no spare positions, they will not be able to pick up additional load. This will result in longer interruptions and a more difficult and costly restoration process.

The current shortage of feeder positions or bus capacity makes it difficult to connect new customers to an optimal supply point within the station service area. In this case, feeders are extended outside the boundary of the station service area, which may require the construction of additional civil infrastructure. Furthermore, load transfers between feeders could also be required to accommodate new customer connection from the nearest available feeder. All these additional factors can add considerable cost and time to the connection project. Table 7 shows the percentage bus loading, the

[10] A3-4WR will be out of service in 2024 for Switchgear replacement
[11] A5-6WR will be replaced by a new Switchgear A11-12WR by 2024
[12] Copeland TS will be in-service by Q4 2018
[13] A1-2CX bus will be loaded in 2020 and A3-4CX in 2021

number of spare feeder positions at Cecil TS, Esplanade TS, Strachan TS, Terauley TS, Windsor TS and Copeland TS as well as the number of customers that could be affected by the failure of each bus.

Therefore, by introducing an additional 144 MVA capacity into the Toronto Hydro System, Copeland TS will help relieve the heavily loaded stations (as identified in Table 7), thus allowing new customers to be connected to their service areas, which would otherwise be difficult and expensive to connect.

It is important to note that the impact of electric vehicle ("EV") deployment has not been accounted for in this forecast. Following the release of the LTEP in the fall of 2017, Toronto Hydro is working with regional planning stakeholders to develop a 25 year load forecast that includes an assessment of different EV deployment scenarios. Large-scale EV deployment may increase the peak load demand at certain stations, thus triggering the need for additional capacity.

E7.4.3.2 Hydro One Contributions

As a part of the IRRP process and Hydro One's long-term investment planning process, the Toronto Region needs are reviewed and agreed upon as a part of the Needs Assessment led by the IESO. The results of the most recent Needs Assessment highlight new emerging needs identified by Hydro One since the previous regional plan and reaffirm needs that were previously identified. These needs are summarized in Table 31, Table 32, and Table 33 in Section E7.4.7.

In response, Toronto Hydro is making capital contributions to Hydro One to carry out upgrades at Hydro One stations during the 2020-2024 period. This is done for large projects where a Toronto Hydro need requires Hydro One to perform a large capital project, such as the Horner expansion, or for projects where Toronto Hydro identifies an opportunity to enable incremental capacity upgrade in coordination with a Hydro One initiated project, such as the identified Hydro One EOL transformer upgrades. Contributing capital to Hydro One allows Toronto Hydro to alleviate capacity constraints on the distribution system by increasing bus firm capacity and increasing available load through transformer upgrades. This enables both customer connections to the system and load transfers which can reduce the risk and duration of outages. Table 8 below provides a summary of these Hydro One contribution projects included in the 2020-2024 filling:

Table 8: 2020-2024 Hydro One Contribution Projects based on the most recent Needs Assessment report

Project	Project Type
Horner Expansion	Station Capacity Expansion
Charles TS – T3/T4 Upgrade	Transformer Upgrade
Duplex TS – T1/T2 Upgrade	Transformer Upgrade
Windsor TS – T1/T2/T3/T4 Upgrades	Transformer Upgrade
Finch TS B-Y Replacement	Bus Replacement

1. Horner TS Expansion

Toronto Hydro plans to make a capital contribution to Hydro One of $34.4 million over the 2020-2024 period for a large-scale expansion project at Horner TS. The result will be an additional capacity of 192 MVA to alleviate forecasted capacity constraints at Manby TS in the South-West area of Toronto. This need has been identified in the Needs Assessment report as shown in Table 32 and as discussed in detail in the IRRP, Section 7.2.3.[14] /C

Figure 2 below shows the four stations in this area that require capacity relief in the near future: Manby TS, Horner TS, Runnymede TS, and Fairbank TS.

[14] Exhibit 2B, Section B, Appendix E

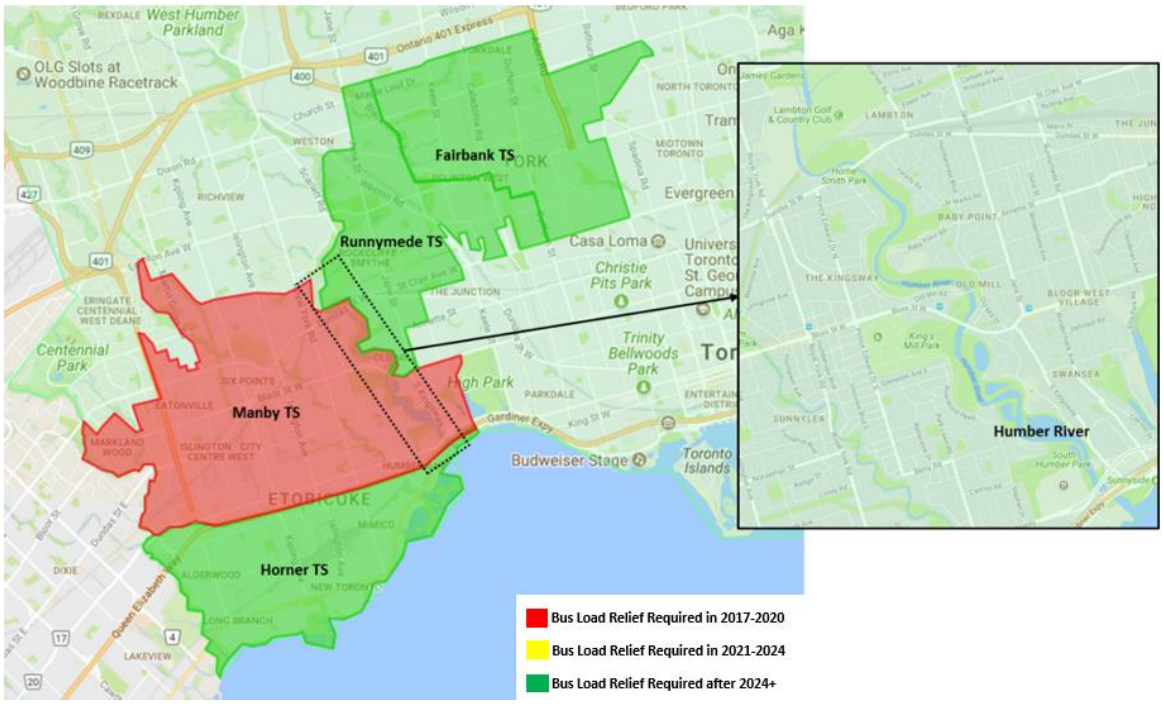


Figure 2: Geographical Spread of South-West Toronto Stations with a visual overview of bus load relief requirements

As shown in Table 9, loading on most station buses identified in Figure 2 above is 75 percent as of 2017. Typically, a 27.6 kV Horseshoe station bus requires relief when the forecasted peak load of a bus reaches 100 percent of the bus firm capacity. Loading is expected to increase at all stations by 2024 if no actions are taken (as seen in Column E). Hydro One is currently installing a new bus (J-Q) at Runnymede TS with an expected in-service date of Q4 2018. This bus will provide an additional 117 MVA capacity to the South-West Toronto area. However, because of the physical barriers posed by the Humber River (see Figure 2), the additional capacity cannot be efficiently utilized to relieve constraints at Manby TS or Horner TS.

As seen in Table 9 below, currently Manby TS and Horner TS have no spare feeder positions available, and by 2020 Manby TS is expected to reach 100 percent capacity and become overloaded. Customers with large loads (14 MVA or more) or DERs introduced into the system require dedicated feeders, which can only be provided if there are spare feeders on a bus. Even if the existing feeders on a bus have capacity, load from large customers cannot be aggregated along these feeders due to the configuration and design of the feeder protection system and the contingency plans. For example, a large customer has enough load that requires supply from two feeders. However, due to contingency setup, this customer will require 3 feeders (two on-load and one standby) so that if any of the on-load feeders fail, the standby feeder can pick up the load. The lack of spare feeder positions prevents Toronto Hydro from implementing this contingency setup for any new large customer connections.

Due to a lack of spare feeder positions, there is a high risk of connection rejection if and when Toronto Hydro receives large customer or DER connection requests in the Manby or Horner TS service areas. In that Toronto Hydro has a statutory obligation to provide access to the grid, Toronto Hydro will be forced to implement expensive load transfers, which cost at least two times more than regular load transfers, to enable the connections.

As seen in column H in Table 9, bus failures at Manby TS or Horner TS would affect an average of 3,560 and 18,312 customers respectively. Investments in this Program would alleviate the risk of bus failure therefore increasing service reliability for these customers.

Table 9: 2017 Summer Load Forecast (South-West Toronto) with no investments

Column A	Column B	Column C	Column D	Column E	Column F	Column H
Station Name	**Bus ID**	**2017 Bus Loading (%)**	**Spare Feeder Position 2017**	**2020 Bus Loading (%)**	**2024 Bus Loading (%)**	**Potential # of CI[15] due to bus failure**
Fairbank TS	*B-Q*	67%	0	64%	76%	17978
	Y-Z	89%	0	88%	91%	11471
Horner TS	*B-Y*	75%	0	80%	83%	18312
Manby TS	*B-Y*	91%	0	95%	98%	4942
	Q-Z	95%	0	103%	106%	2921
	V-F	76%	0	91%	99%	2824
Runnymede TS	*B-Y*	90%	0	61%	63%	21205
	J-Q [1]	--	0	73%	75%	--
Richview TS	*B-Y*	40%	0 [2]	43%	44%	248
	J-E	70%	0	60%	62%	2914
	Q-Z	43%	0	47%	49%	2059

Note: Red ≥ 100 percent and orange is ≥ 95 percent

To provide capacity relief at Manby TS, Toronto Hydro has performed several load transfers to Horner TS and Richview TS as summarized in Table 10 below.

15 "CI": Customers Interrupted
[1] J-Q is the new Runnymede TS bus. It is expected to be in-service by Q4 2018
[2] B-Y bus has feeders that are owned by Alectra utility

Table 10: Load transfer from Manby TS to Horner TS and Richview TS

Load Transfer	2015	2016	2017	Total
Manby TS to Richview TS (MVA)	13	8	--	**21**
Manby TS to Horner TS (MVA)	--	--	3	**3**

Toronto Hydro assessed several capacity relief alternatives, including DR and using Richview TS to pick up additional load from Manby TS. It was found that an upgrade of Hydro One's Horner TS transformation capacity is the most feasible and cost-effective option. A detailed options analysis can be found in Section E7.4.5.2. For additional details on the Richview TS option, please refer to section 7.2.3 of the IRRP report for the Central Toronto area.[16]

2. Hydro One Transformer Upgrades

Toronto Hydro is planning to contribute capital to Hydro One to upgrade three transformers during the 2020-2024 period to alleviate capacity constraints. Initiated by Hydro One's sustainment plans and included in the Needs Assessment report (see Table 32), the proposed investments will enable incremental capacity upgrades at Hydro One-owned transformer stations to enable customer connections and to mitigate capacity constraints at the same time that Hydro One is replacing EOL equipment in its stations.

Based on the RIP report[17] Charles TS, Duplex TS, and Windsor TS are expected to reach above 95 percent station capacity[18] within 15-20 years from 2020. When these stations are overloaded, Toronto Hydro will be unable to connect new customers within these service areas or to provide reliable service to its existing customers. As mentioned earlier, the downtown core stations serve primarily institutional, commercial, and large residential condominium customers, who prioritize reliability and resiliency over all other factors given the essential services they provide. For such customers, the cost of power interruptions outweighs the cost of distribution rate increases, and it is crucial to avoid interruptions by adding capacity to the system.

In response, Toronto Hydro plans to provide capital contributions to Hydro One to upgrade the transformers identified in Table 11. For each project, Toronto Hydro plans to request transformer

[16] Exhibit 2B, Section B, Appendix E
[17] Exhibit 2B, Section B, Appendix C
[18] A 13.8 kV downtown station bus load relief is required when the forecasted peak load of a bus reaches 95% of the bus firm capacity.

upgrades (from the current 75 MVA to 100 MVA). These investments are estimated to add approximately 188 MVA of capacity (see Table 11 Column C) to the system over the next 10-15 years. The geographical distribution of these transformers can be seen in Figure 3.

Table 11: Hydro One Transformer Replacement

Column A	Column B		Column C
Project	**Transformer Ratings (MVA)**		**Final Post-Replacement Capacity Additions** [19]
	Existing	**New**	
Charles TS – T3/T4 Upgrade	75	100	54 MVA
Duplex TS – T1/T2 Upgrade	75	100	54 MVA
Windsor TS – T1/T2/T3/T4 Upgrades	75	100	80 MVA
Total			**188 MVA**

Figure 3: 2020-2024 Hydro One Transformer Upgrade Projects

[19] Following a Hydro One transformer upgrade, additional investments may need to be made to realize all of the available capacity. For example, the station switchgear may need to be replaced or the transformer's pair may need to be upgraded. Toronto Hydro replaces end-of-life transformer station switchgear in the Station Renewal program (See Exhibit 2B, Section E6.6 Station Renewal – Section E6.6.3.1 sub-section 1 TS Switchgear).

Upgrading these transformers in tandem with Hydro One's renewal and sustainment plans would alleviate capacity constraints on the system and result in avoided costs of up to $20 million (as shown in Table 12) thus reducing the burden on ratepayers. This benefit is possible given the Transmission System Code cost allocation rules: when work is being undertaken by the transmitter in the normal course, the distributor is only responsible for paying the incremental cost of an equipment upgrade; on the other hand, if the work is initiated by the distributor, the rules shift much of the cost burden onto the distributor.[20] For example, Hydro One will invest $5.5 million to replace and upgrade the existing T3 and T4 transformers at Charles TS. Of the $5.5 million, $0.5 million is paid by Toronto Hydro in the form of capital contribution for requesting capacity increase of the new transformers from 75 MVA to 100 MVA. In this scenario, Toronto Hydro benefits from capacity gains due to higher transformer ratings. At the same time, it is able to avoid an additional $5 million in costs (as shown in Table 12 below) as a result of not having to pay for the entire transformer replacement cost.

Table 12: Avoided Costs by aligning with Hydro One sustainment plans ($ Millions)

Project	Cost if independent of Hydro One sustainment plans	Cost if undertaken with Hydro One sustainment plan	Avoided Cost
Charles TS – T3/T4 Upgrade	5.5	0.5	5.0
Duplex TS – T1/T2 Upgrade	5.5	0.5	5.0
Windsor TS – T1/T2/T3/T4 Upgrades	11	1.0	10.0
Total	**22.0**	**2.0**	**20.0**

Additionally, when Hydro One replaces a transformer, the incremental cost of installing a larger unit is relatively small in relation to the incremental capacity derived from the investment, resulting in considerable savings per MVA of installed capacity. Section E7.4.5.2 sub-section two outlines the typical differences between replacing a 75 MVA transformer with a like-for-like transformer and a higher rated 100 MVA transformer.

If the transformers identified in Table 11 are not upgraded and are instead replaced on a like-for-like basis (i.e. 75 MVA to 75 MVA) during the 2020-2024 period, the capacity of the existing buses connected to these transformers will be stranded (i.e. limited), as seen in Table 13 below. This will

[20] Transmission System Code, Section 6.3 - Cost Responsibility for New and Modified Connections.

result in increased capacity constraints on the system. Additionally, if the transformer upgrades are not carried out in the 2020-2024 period, Hydro One is unlikely to replace them again within the next 45 years[21] and Toronto Hydro would need to replace these busses as part of the Stations Renewal program[22] within the next 15 years due to increased loading as indicated in Appendix C (Metro Toronto Regional Load Forecast) of the RIP report.

Table 13: List of Toronto Hydro Owned Busses Connected to Hydro One Transformers

Column A	Column B	Column C	Column D	Column E	Column F	Column G	Column I
Station – Transformer	**Connected Bus**	**Existing Bus Capacity**	**2017 Bus Loading (%)**	**Spare feeder position 2017**	**2020 Bus Loading (%)**	**2024 Bus Loading (%)**	**Potential # of CI[23] due to bus failure**
Charles TS – T3/T4	*A1-2CS*	45 MVA	67%	1	73%	76%	3044
	A3-4CS	45 MVA	76%	0	89%	91%	3254
Duplex TS – T1/T2	*A1-2DX*	45 MVA	69%	0	82%	84%	5767
	A3-4DX	45 MVA	69%	0	78%	80%	1723
Windsor TS – T1/T2/T3/T4	*A5-6WR*	59 MVA	90%	0	14%	93%	434
	A3-4WR	59 MVA	88%	0	90%	0%	5838
	A13-14WR	41 MVA	95%	0	85%	88%	21
	A17-18WR	49 MVA	88%	0	73%	76%	227

Note: For Bus Loading, red represents ≥85 percent and orange ≥80 percent.

3. Finch B-Y Bus Replacement

Finch TS is a Hydro One owned station located in the Finch Avenue and Weston Road area. Hydro One intends to replace its legacy air-insulated 27.6 kV outdoor B-Y bus and rebuild the switchgear yard at Finch TS in 2024. This rebuild work will include the installation of a new 27.6 kV outdoor metalclad switchgear with twelve circuit breaker positions (or more) to replace the existing B-Y bus. The existing B-Y bus has 12 EOL bulk oil circuit breakers and Toronto Hydro owns six of them. Toronto Hydro intends to make a total capital contribution of $4.1 million to Hydro One to replace the existing six breakers on B-Y bus with six new ones on a new bus.

[21] Kinectrics "Useful Life of Assets" Report, filed in the EB-2010-0142 application (Exhibit Q1, Tab 2)
[22] Exhibit 2B, Schedule E6.5, Section E6.5.3.1 sub-section 1
[23] "CI": Customers Interrupted

Typically, Toronto Hydro would replace these obsolete oil circuit breakers with vacuum circuit breakers through its Stations Renewal program.[24] However, in this case, since Hydro One is replacing the entire B-Y bus along with all its circuit breakers, Toronto Hydro will make a capital contribution to Hydro One to transfer ownership from the existing 6 circuit breakers on the B-Y bus to six new circuit breakers on the new Hydro One-owned 27.6 kV bus.

The outdoor oil circuit breakers at Finch TS were installed in the 1960s and 1970s and are past their 45 year useful life. These legacy units show signs of moderate and accelerated deterioration, and need to be replaced to mitigate the failure risk associated with their obsolete oil-based technology. Although a fault would normally only cause a localized outage on the feeder protected by the breaker, when a TS outdoor circuit breaker fails, thousands of customers will be affected because a fault would extend the outage to all customers supplied by the station bus. If the B-Y bus at Finch TS experienced a failure, the outage could last between one to two hours and could potentially impact around 13,000 customers in the service area.

Toronto Hydro experienced an outage of this nature on August 4, 2017, when an outdoor breaker at Finch TS failed to open during a fault. Bus protection was forced to operate, interrupting power to nearly 5,000 customers. The majority of customers were restored within an hour of the initial incident; however, all of those customers were supplied by feeders that would not have suffered an outage had the outdoor breaker operated as designed.

E7.4.3.3 Local Demand Response

The Local DR segment includes conservation programs and technological solutions that encourage load curtailment and load-shifting, including targeted DR resource procurement at two stations: Cecil TS (a continuation of the current local DR program) and Basin TS. Locally targeted, customer-centric initiatives promote the adoption of existing and new DR technologies.[25] These investments enable the utility to address capacity constraints using targeted deployment of DR, expanding the planning toolbox beyond conventional wires solutions when evaluating options to address medium term capacity needs. DR strategies do not permanently replace the need for traditional wires solutions, but rather provide the utility with far more flexibility in terms of the timing of capacity upgrades and the ability to decide what parts of the station will be upgraded versus which parts can be deferred. This enables optimal deferral of investment costs, while allowing for re-allocation and optimization

[24] See Exhibit 2B, Section E6.6 Stations Renewal, Section E6.6.3.1 sub-section 2 TS Outdoor Breakers for more detail.
[25] See Exhibit 4A, Tab 2, Schedule 9 – Asset and Program Management, 7. Local Demand Response

of capital as medium-term investment options are considered. Local DR also supports the goals of the Toronto IRRP and the LTEP to meet local needs with DERs, conservation programs and DR strategies.

Local DR is most appropriate in service areas requiring non-urgent load relief to provide sufficient time to penetrate the market. Suitable candidate stations must have adequate lead-time (two to three years) for the implementation of a DR solution before a capacity constraint is expected to materialize. Toronto Hydro targets stations that exhibit physical or logistical barriers for pursuing conventional station expansion solutions, making the DR option significantly more cost-effective in the short-to-medium term. Further, DR works best at stations with load profiles that demonstrate short and infrequent system peaks. In Toronto Hydro's service area, these temporary "spikes" in customer demand typically occur during the hottest weekday afternoons in the summer when maximum cooling loads amplify the normal daily peaks that result from electrical building system and operational end-uses. Stations that serve a range of larger customers (greater than 3 MW average monthly peak demand) that have flexible operational profiles are best suited to DR solutions.

Local DR is needed to address capacity constraints that are forecast to start affecting the identified stations by as early as 2022**.** Implementing this program is expected to mitigate the risks of operating the system beyond its capacity and avoid the need to undertake complex and impractical load transfer projects to free up capacity for new customers. Failing to address capacity constraints can lead to operational and reliability risks by 2022, as shown in Table 14 below.

As can be seen in Table 14, Basin TS will reach 85 percent loading by 2020, and approach 90 percent by 2024. As such, Toronto Hydro has adequate lead-time to implement DR measures that can help defer the need for costly capital investments, while also providing sufficient buffer to allow for the implementation of wires solutions if needed. In the case of Cecil TS, which will reach 85 percent loading by 2024, there is no lead-time required as the proposal is to continue the current Local DR program, which was developed, implemented, and tested during the 2015-2019 period. Failure to implement Local DR could result in reduced reliability, costly short-term load transfer projects, reduced flexibility to schedule maintenance outages, inability to accommodate distributed generation (e.g. combined heat and power), increased risk of equipment failure, and inability to connect new loads. Operating station busses at high capacity puts the system at risk of violating design parameters, which could result in rotating blackouts and voltage reductions.

Table 14: 2016 Station Load Forecast for Selected Stations

Station/Bus	Firm Capacity (MVA)		Year								
	100%	95%	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cecil (115 kV/13.8 kV) TS (Weather corrected busses to 32°C)											
A1-2	47	45	27	27	27	27	27	27	27	28	28
A3-4	47	45	35	36	36	37	37	37	38	38	38
A5-6	72	68	53	57	61	67	71	73	73	74	74
A7-8	72	68	56	57	57	59	60	60	61	61	62
Total of all Busses	238	226	171	177	181	190	195	197	199	201	202
Surplus MVA			67	61	57	48	43	41	39	37	36
% Loading (Load/2016 Firm Cap)			72%	74%	76%	80%	82%	83%	84%	84%	85%
Basin (115 kV/13.8 kV) TS (Weather corrected busses to 32°C)											
A5-6	49	47	32	35	44	47	49	49	50	50	50
A7-8	49	47	21	27	28	32	34	36	36	36	37
Total of all Busses	98	94	53	62	72	79	83	85	86	86	87
Surplus MVA			45	36	26	19	15	13	12	12	11
% Loading (Load/2016 Firm Cap)			54%	63%	73%	81%	85%	87%	88%	88%	89%

Toronto Hydro proposes to continue Local DR at Cecil TS. That project has had considerable uptake from several large (>1 MW) customers with an interest in longer-term DR contracts (beyond the current 2019 program end date, preferably for 3-5 year terms). There are also numerous smaller commercial customers (500 kW to 1 MW) interested in DR to support customer-funded storage projects. The station load forecast (see above) shows a continued need for load reduction at Cecil TS. DR remains a more cost-effective and customer-friendly approach compared to conventional wires solutions.[26]

The next phase of the Local DR program is expected to achieve a total of 11 MVA (about 10 MW) of peak demand reduction between 2020 and 2024 at an all-in projected cost of $10.3 million (60percent operational expenditures, 40 percent capital expenditures). The operational

[26] For the cost-effectiveness analysis of DR versus wires, please see section E7.4.5.3.

expenditures will fund the cost of program administration, customer incentives, and consultant and technology fees (e.g. the cost of procuring DR software).[27] The capital expenditures will fund the cost of Toronto Hydro-owned battery storage at Basin TS.

By curtailing 10 MW of peak load, Toronto Hydro can defer capital investment that would otherwise be required in 2022-2024 or shortly thereafter to provide bus relief at these stations by five to six years. Without investment in this Local DR solution, conventional wires solutions would be required at a cost of $135 million to avoid reliability risks and meet Toronto Hydro's obligations to customers (see Section E7.4.5.3).

Both Cecil TS and Basin TS serve primarily institutional and commercial customers. The demand at Cecil TS is 43 percent institutional customers (e.g. hospitals and universities) and 25 percent commercial customers, with the remaining demand being residential. Basin TS serves 35 percent institutional customers (e.g. City of Toronto waste water treatment plants, healthcare facilities, Metrolinx/Go Transit), 30 percent commercial customers, 3 percent industrial, with the remaining being residential.

Given the criticality of loads associated with critical services, resiliency and reliability are extremely important at both stations. Local DR responds to the need for resiliency and reliability in these areas while incentivizing customers to change their behaviour and contributing to an overall benefit to all ratepayers. Keeping these essential services running smoothly is important to all Toronto Hydro customers, regardless of their rate class.

E7.4.4 Expenditure Plan

Table 15: Historical & Forecast Program Costs by Segments ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Copeland TS Expansion	20.5	19.1	22.0	7.4	7.8	8.9	29.7	38.8	1.0	--
Hydro One Contributions	2.5	15.3	37.4	22.7	21.5	10.6	10.3	10.5	10.2	11.7
Local Demand Response	--	--	0.1	0.5	3.6	--	--	--	1.2	3.4
Total	**23.0**	**34.4**	**59.4**	**30.6**	**32.8**	**19.5**	**40.0**	**49.3**	**12.5**	**15.2**

[27] Exhibit 4A, Tab 2, Schedule 9 – Asset and Program Management.

Spending in the Stations Expansion program over the 2015-2019 period is projected to be $180.1 million.

Toronto Hydro proposes to spend $136.4 million over the 2020-2024 period to add or free up 415 MVA of capacity on its system. This is $43.7 million less than what is forecasted to be spent over the 2015-2019 period. The proposed projects in the Stations Expansion program are based on Hydro One sustainment plans and the IRRP Needs Assessment report. Given the complexity and size of these individual projects, their expenditures are discrete and not conducive to smoothing over the rate period. Moreover, these projects entail extensive coordination with Hydro One and other stakeholders (such as contractors, vendors, public etc.), long lead times for ordering equipment, and logistical challenges in heavy electrical equipment delivery. Due to these challenges, the Stations Expansion program is susceptible to fluctuations in spending from year-to-year. As such, the historical and proposed spending reflect significant variations from year to year.

E7.4.4.1 Copeland TS – Phase 2

Toronto Hydro forecasts to spend $76.8 million on Copeland TS – Phase 1 and 2 over the 2015-2019 rate period, and $78.4 million during 2020-2024 rate period on completing Copeland TS - Phase 2. A breakdown of the budget is shown below in Table 16.

Table 16: 2015-2024 Budget (Actual/Bridge/Forecast): Copeland TS – Phase 1 and Phase 2 ($ Millions)

Asset Class	Actuals			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Copeland TS – Phase 1	20.5	19.1	21.5	5.6	--					
Copeland TS – Phase 2	--	--	0.5	1.8	7.8	8.9	29.7	38.8	1.0	--
Total	**20.5**	**19.1**	**22.0**	**7.4**	**7.8**	**8.9**	**29.7**	**38.8**	**1.0**	**-**

1. Copeland TS – Phase 1

Copeland TS – Phase 1 is a large and complex project of unprecedented scale for Toronto Hydro. It is a uniquely challenging project in the dense urban core of the City. The Copeland TS design places most of the equipment underground and includes a tunnel connection to Hydro One's Front Street tunnel.

Due to several unforeseen events and factors, including the effect of unusually adverse weather events, challenging site conditions, logistical challenges, and contractor performance, construction of Copeland TS – Phase 1 has encountered schedule and spending delays. Construction is expected to be completed in 2018 at a projected cost $66.7 million, which is $15.1 million higher than forecasted in the 2015-2019 rate filing for 2018. However, the overall Copeland TS – Phase 1 budget from project inception to project completion in 2018 has not materially changed. Furthermore, the timing of the expenditures proposed in the 2015-2019 CIR filing have shifted as a result of the delay to the construction schedule.

2. Copeland TS – Phase 2

Copeland TS – Phase 2 is expected to be completed by late 2023 or early 2024. Certain limited pre-construction work related to this project commenced in 2017. This project has to start in the 2017-2019 period to meet the long lead times associated with manufacturing, delivery, and assembly of power transformers and switchgear. There are three major activities to be completed in the 2017-2019 timeframe: contractor Request for Proposal (“RFP”)-related activities, design and engineering, and certain pre-construction work. These major activities are forecasted to cost $10.0 million during the 2017-2019 period.

In 2017, Toronto Hydro developed and issued contractor RFPs for competitive bids. Based on the responses from bidders, budget and schedule for Copeland TS – Phase 2 will be updated in late 2018 or early 2019. In 2018, at least two contractors are expected to be selected: a primary Engineering, Procurement, and Construction (“EPC”) contractor, an engineering consulting firm, and potentially one or more specialist firms to carry out inspections, audits, and payment verification. The selected EPC contractor is also expected to complete design and engineering work ahead of 2020 so that the major electrical equipment can be purchased following the issuance of the OEB’s decision in respect of this application. Some pre-construction work, along with development of logistical and transportation plans, acquisition of permits, and public engagement plans are also expected to be carried out in 2018 and 2019.

The expenditure plan for Copeland TS – Phase 2 was developed based on the actual costs of Copeland TS - Phase 1, plus additional considerations based on lessons learned from Copeland TS - Phase 1 (detailed in Section E7.4.6 Execution Risks & Mitigation) as well as certain unique attributes and challenges of Copeland TS - Phase 2 that were not applicable to Copeland TS - Phase 1, including:

- **Construction within an energized station:** Copeland TS - Phase 2 requires construction, testing, and commissioning of equipment in an already energized Copeland TS. In addition to safety issues related to working near live equipment, contractors must coordinate work with Toronto Hydro and Hydro One personnel working in the station. Increased logistics limitations also exist due to the presence of cable racking and HVAC and mechanical equipment.

- **Public access and stakeholder relations:** The public and neighbouring businesses will be utilizing the roof and surrounding sidewalk areas of Copeland TS while Copeland TS - Phase 2 construction is in process.
- **Roof opening**: A roof opening needs to be made to transport large equipment into the station and then be re-constructed after the work is completed.
- **Cable installation***:* Copeland TS - Phase 2 involves the installation and routing of additional High Voltage ("HV"), Medium Voltage ("MV"), and control cables in the station basement, utilizing existing cable racks and trays. Since existing cable racks and trays will already be carrying cables installed during Copeland TS - Phase 1, it would be challenging to pull cables through the limited basement space.
- **Utilization of EPC contractor**: Schedule and budget will be developed and managed by the EPC contractor.

The 2017-2024 budget for Copeland TS – Phase 2 includes the following tasks:

- Design and Pre-Construction
- Major Electrical Equipment:
- Procurement of 3 power transformers, 3 switchgears, and HV/MV/control cable
- Installation, testing and commissioning of major electrical equipment
- Cable installation, termination, testing and commissioning
- Installation of Protection and Control, and metering equipment
- Construction:
- Including civil, facilities, station services, landscaping, room finishes, and enhancements to IT, SCADA and communications systems
- Project Management and Ancillary Cost:
- Third-party review and verification, including payment verification
- Acquisition of permits, insurance, public relations, liaison and coordination with relevant stakeholders, including the City, Ministry of Labour, other authorities, and Hydro One

A summary of the Copeland TS – Phase 2 schedule and annual cost is shown below in Table 17:

Table 17: Summary Schedule and Annual Cost of Copeland TS – Phase 2

Year	Budget ($ Millions)	Work Schedule
2017	0.5	Design
2018	1.8	Design
2019	7.8	Design and Pre-Construction
2020	8.9	Pre-construction Project Management and Ancillary Cost Major Electrical Equipment
2021	29.7	Project Management and Ancillary Cost Major Electrical Equipment
2022	38.8	Project Management and Ancillary Cost Major Electrical Equipment Construction
2023	1.0	Project Management and Ancillary Cost Major Electrical Equipment Construction

E7.4.4.2 Hydro One Contribution

Toronto Hydro forecasts to spend $99.4 million on Hydro One capital contributions over the 2015-2019 rate period, and $53.3 million over the 2020-2024 rate period. The expenditures include contributions to Hydro One for stations expansions (i.e. Runnymede TS and Horner TS), transformer upgrades and related work, and bus replacements. These projects are planned based on the Needs Assessment (see Table 31, Table 32, Table 33 in Section E7.4.7).

Table 18: 2015-2024 Budget (Actual/Bridge/Forecast): Hydro One Contribution ($ Millions)

Asset Class	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Runnymede TS Expansion	0.08	13.6	36.0	5.8	--	--	--	--	--	--
Horner TS Expansion	0.05	0.3	--	15.0	19.4	10.6	7.8	8.0	8.0	--
Hydro One Transformer Upgrades and Related Work	2.3	1.4	1.4	1.9	2.1	--	0.5	0.5	0.1	2.0
Finch TS B-Y Bus Replacement	--	--	--	--	--	--	--	--	0.1	4.0
Reactive Hydro One Contribution	--	--	--	--	--	--	2.0	2.0	2.0	5.7
Total	**2.5**	**15.3**	**37.4**	**22.7**	**21.5**	**10.6**	**10.3**	**10.5**	**10.2**	**11.7**

1. 2015-2019 Expenditure Costs

Over the 2015-2019 rate period, Toronto Hydro expects to spend $99.4 million on Hydro One contributions, which is approximately $7.4 million less than forecasted. This variance is attributable to: Runnymede TS expansion cost estimate changes, South-West Toronto needs and scope changes, Hydro One transformer upgrades and related projects, and Hydro One cost reconciliation. A more detailed comparison is shown in Table 19 and further discussed below.

Table 19: Hydro One Contribution – Historical Spending Analysis ($ Millions)

Projects	2015-2019 Filed Cost	2015-2019 Actual/Forecast Cost	Variance
Horner Expansion	72.0	34.8	(37.2)
Runnymede Expansion	33.0	55.5	22.5
Hydro One Transformer Upgrades & Related Work	1.8	9.1	7.3
Total	**106.8**	**99.4**	**(7.4)**

a. *Runnymede TS Expansion Cost Estimate Changes:*

In the 2015-2019 rate application, Toronto Hydro forecasted a $33 million capital contribution to Hydro One for the Runnymede TS expansion based on high level equipment and construction costs available at the time. In Q2 2016, Hydro One made available a Class C (+50 percent/-20 percent) cost estimate of $37 million, which included an expansion to the 115-27.6 kV Runnymede TS consisting of two new 50/83 MVA transformers and the re-conductoring of the 115 kV transmission circuits (K1W, K3W, K11W and K12W), each of which is approximately 10 kilometres long between Manby TS and Wiltshire TS. In Q4 2016, Hydro One provided Toronto Hydro with a Class B estimate (+/-20 percent) of $55.5 million, noting that the original Class C estimate for the circuit re-conductoring work did not consider and include:

- Replacement of steel members (required on 90 percent of structures) in the circuit conductors;
- Construction complexities due to working in a congested corridor in the City; and
- More complex outage requirements at Manby TS, Runnymede TS, and Wiltshire TS than originally expected.

b. <u>South-West Toronto Needs/Scope Change:</u>

In the 2015-2019 rate application, Toronto Hydro proposed to construct and own a 100 MVA transformer station in the Manby TS area for $72 million. However, once the feasibility study was completed in 2014, Toronto Hydro determined that building a new station would require longer implementation time and higher cost compared to other options (see section E7.4.5.2 sub-section 1 for additional details). The preferred option of Horner TS expansion will cost $30.4 million during 2015-2019 and $34.8 million during 2020-2023. This option allows Toronto Hydro to avoid approximately $7.2 million while addressing the capacity needs in the South-West Toronto region.

As noted in section E7.4.3.2 sub-section 1 (Table 10), pending the completion of the Horner TS expansion, Toronto Hydro undertook several much needed load transfer projects to relieve capacity constraints at Manby TS. These investments resulted in increased flexibility with respect to the need date for the Horner TS expansion.

c. <u>Hydro One projects:</u>

Over the 2015-2019 period, Toronto Hydro expects to undertake several projects that were not included in the 2015-2019 DSP at a total cost of $2.3 million. These projects are driven by Hydro One sustainment plans.

- **Transformer upgrades:** $0.8 million capital contribution to Hydro One to upgrade transformers at Cecil TS, Dufferin TS, and Main TS from 75 MVA to 100 MVA. These projects were not included in the 2015-2019 DSP due to the timing of Hydro One's sustainment plans.
- **Bridgman TS cable replacement**: $0.7 million capital contribution to Hydro One in support of the replacement of Toronto Hydro-owned 13.8 kV LV cables between Bridgman TS and High Level TS to mitigate reliability issues. This work carried out by Hydro One addressed Toronto Hydro's needs by modifying the incoming circuit breakers at High Level TS to enable the connection of the new cables.
- **Bridgeman TS potential transformer and metering upgrade:** $0.8 million capital contribution to Hydro One for the replacement of EOL, legacy oil-filled potential transformers ("PTs"). To ensure the proper function of Toronto Hydro's protection and control system at Bridgman TS, Hydro One was required to perform certain modifications for Toronto Hydro.

d. Hydro One Cost Reconciliations:

Pursuant to applicable cost recovery agreements (including criteria regarding cost reconciliation review), Toronto Hydro incurred $2.3 million to reconcile past Hydro One capital contributions. Such reconciliations are typically based on actual asset or station loading and project in-service anniversaries, making the costs difficult to forecast in advance.

- **Cecil TS 10-Years True-Up:** $1.8 million in capital contributions to Hydro One for the 10-year economic evaluation period ("EEP") of the 2005 Cecil TS T3/T4 transformer upgrade. This payment accounted for the variance between the forecasted load at the time of the transformer upgrade and the actual load at the end of the EEP.
- **Richview TS 10-Years True-Up:** $0.5 million in capital contributions to Hydro One for the 10-year EEP of the 2006 installation of two feeder breaker positions at Richview TS. This payment accounted for the variance between the forecasted load at the time of the breaker installations and the actual load at the end of the EEP.

2. 2020-2024 Forecast Expenditures

As evidenced in the 2015-2019 period, given the nature of work performed under the Hydro One Contribution segment, expenditures are susceptible to large fluctuations from year-to-year. This is due to the dependency on Hydro One's sustainment plans and the complexity and size of individual projects which make the spending discrete and irregular. For 2020-2024, Toronto Hydro's proposals are based on the best available information as of 2018.

a. Horner TS Expansion

Toronto Hydro anticipates that the cost to complete the Horner TS Expansion will be $69.2 million, mostly in the form of capital contribution to Hydro One. The forecast includes $45.4 million to complete the Horner expansion work by 2020 and is based on the Class C estimate provided by Hydro One. The remainder $23.8 million is required for civil infrastructure enhancement work within Hydro One's yard to enable feeder transfers from Manby TS. Table 20 below outlines the payment breakdown to Hydro One by year.

Table 20: Horner TS Expansion Hydro One Payment Breakdown

Project	Cost ($ Millions)	Payment Year
Horner TS Expansion	0.4	2015-2016
	34.4	2018-2019
	34.4	2020-2023

b. Hydro One Transformer Upgrades

As noted in section E7.4.3.2 sub-section 2 above, Toronto Hydro plans to make capital contribution to Hydro One to upgrade certain EOL transformers from 75 MVA to 100 MVA. Table 21 below outlines the payment breakdown to Hydro One by years. Toronto Hydro forecasts that the cost to complete this work will be $3.1 million. The forecast is based on:

- **Hydro One's sustainment plans**: Total number of transformer upgrade projects during the 2020-2024 period are based on this plan which aligns with the Needs Assessment (see Table 33).
- **Actual project costs**: Unit cost of forecasted projects are based on completed and ongoing transformer upgrade projects executed between 2015 and 2018.

Table 21: Transformer Upgrades Hydro One Payment Breakdown

Hydro One Transformer Upgrades	Cost ($ Millions)	Payment Year
Charles TS – T3/T4	0.1	2018
	0.5	2021
Duplex TS – T1/T2	0.1	2019
	0.5	2022
Windsor TS – T1/T2/T3/T4	0.1	2023
	2.0	2024

c. Hydro One Bus Replacement: Finch TS B-Y Bus

As noted in section E7.4.3.2 sub-section three, Toronto Hydro plans to make capital contributions to Hydro One to replace six EOL bulk oil circuit breakers connected to Hydro One's legacy air-insulated 27.6 kV outdoor B-Y bus at Finch TS. This is part of Hydro One's Finch TS switchgear refurbishment plan where Hydro One plans to install a new bus to replace the existing B-Y bus. Toronto Hydro estimates that its cost to complete this work will be $4.1 million, all in the form of capital contribution to Hydro One. This project is at its preliminary stage and Hydro One has yet to share detailed plans regarding the installation of the new metalclad switchgear. Therefore, the forecast is based on historical Hydro One owned bus replacement work, where Toronto Hydro has contributed toward upgrades. Table 22 below outlines the payment breakdown to Hydro One by year.

Table 22: Finch TS B-Y Bus Replacement Hydro One Payment Breakdown

Project	Cost ($ Millions)	Payment Year
Finch TS: B-Y Bus Replacement	0.1	2023
	4.0	2024

d. Reactive Hydro One Contribution

As noted above, Toronto Hydro incurred an additional $4.6 million in the form of capital contribution for several Hydro One projects that were not included in the 2015-2019 DSP. To account for any anticipated but yet to be identified Hydro One projects, Toronto Hydro has allocated $11.7 million as "Reactive Hydro One Contribution" during the 2020-2024 rate period. This budget is required to support projects triggered by Hydro One sustainment plans such as cable, switchgear or transformer replacements or upgrades. For example, Hydro One currently plans to upgrade three transformers (T11, T12, and T13) at Bridgman TS from 66.6 MVA to 100 MVA in 2020. Following the upgrades, additional capital contributions may be required from Toronto Hydro (e.g. to support switchgear replacements) so as to realize all of the additional available capacity.

This forecasted amount will enable Toronto Hydro to account for any cost reconciliations, which are typically based on actual asset or station loading and project in-service anniversaries, and are difficult to forecast in advance. True-up payments may result from variances between forecasted load at the time of asset upgrade and the actual load at the end of the EEP.

This amount would also enable Toronto Hydro to account for any policy changes pending more detailed planning and coordination with Hydro One.

E7.4.4.3 Local Demand Response

Table 23: 2015-2024 Budget (Actual/Bridge/Forecast): Local Demand Response ($ Millions)

Asset Class	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Local DR Program	--	--	--	0.5	3.6	--	--	--	1.2	3.4
Total	**--**	**--**	**--**	**0.5**	**3.6**	**--**	**--**	**--**	**1.2**	**3.4**

Over the 2015-2019 period, Toronto Hydro forecasts to spend $4.1 million in the Local DR segment for the purchase and installation of a battery for Cecil TS. The battery storage costs are estimated based on market costs for utility grade equipment, and installation estimates based on utility scale projects underway in Toronto over the 2015-2018 period.

Over the 2020-2024 period, Toronto Hydro forecasts to spend $4.6 million for the battery storage project in the Basin TS area. Similarly to the Local DR at Cecil TS, the capital cost of the battery and its installation is estimated based on the same assumptions regarding market costs and comparable projects.

The bulk of the total 2020-2024 Local DR program cost (e.g. incentives, labour) is not capitalized and therefore not included in Table 23. 60 percent of the $10.3 million total program cost is operating expenditures relating to program administration, customer incentives for DR activities, marketing and legal costs, and measurement and verification costs, as detailed in the Asset and Program Management program.[28]

E7.4.5 Options Analysis

Toronto Hydro has identified and evaluated various options based on current and future needs of the system.

E7.4.5.1 Options for Copeland TS

1. **Option 1: Do Nothing**

Do nothing is not a feasible option as it does not provide the necessary load relief and feeder positions required at downtown core stations (see Table 7 Columns D and E). This option would result in most busses being heavily loaded by 2024, including eight at 90 percent or above and two at more than 100 percent capacity. Toronto Hydro anticipates the remaining spare feeder positions will also be used up by 2024, which means that it will be very difficult, and in some cases impossible, for Toronto Hydro to connect new customers, including DERs, at these stations.

[28] See Exhibit 4A, Tab 2, Schedule 9 – Asset and Program Management

2. Option 2 (Selected Option): Copeland TS – Phase 2

Incremental to Copeland TS - Phase 1, construction and procurement for the Copeland TS - Phase 2 project is proposed to commence in early 2020 (with design expected to be completed over 2017-2019), providing an additional 144 MVA capacity in the area by 2024. Copeland TS - Phase 2 includes the installation of 2 additional 72 MVA busses, 3 gas insulated power transformers (two load-serving and one back-up), and a transfer bus to allow use of the spare transformer to back-up Copeland TS and other stations through the installation of ties.

This option includes a spare transformer and a transfer bus. This would allow Toronto Hydro to fully utilize the space and infrastructure installed in Copeland TS - Phase 1, while minimizing the need and cost associated with re-entering the station (i.e. equipment delivery and redoing the landscaping). The cost associated with the installation of these assets is estimated to be $1.5 million. Additionally, the spare transformer is required given the uniqueness of the SF_6 transformers that will be installed at the station and the long lead times (over a year) to procure replacement units. The failure risk of a SF_6 transformer is very low. However, if a failure were to happen, the Copeland station load supplied by the failed transformer would be under contingency without any outage to the customer. The contingency state would exist until the load at risk can be transferred to nearby stations.

This option would also provide a significant number of feeder positions to allow for bus load rebalancing in the area, facilitate future switchgear replacements (particularly at Windsor TS), and provide additional security of supply to critical downtown customers.

Regardless of whether one or two 72 MVA busses are installed, Toronto Hydro will still require the installation of two power transformers for contingency purposes. Through the installation of the second bus, Toronto Hydro is able to utilize the stranded transformation capacity which would otherwise remain unused. Other benefits of Copeland TS – Phase 2 include the following:

- Additional support for adjacent station (Windsor TS, Esplanade TS, Terauley TS, Strachan TS, and Cecil TS) through load transfers.
- Execution of work without streetscape impact, traffic congestion, or permanent visual disturbance to the area since all civil work will be completed as part of Copeland TS - Phase 1.
- Additional capacity for the proposed developments of the West Donlands, East Waterfront and the Portland's areas.

- Minimal additional HV connection work beyond what was completed as part of Copeland TS - Phase 1.

3. Option 3: Expansion of Esplanade TS

This option would involve working with Hydro One to construct a new building on the existing Esplanade TS site, perform necessary transmission upgrades (as determined by Hydro One), install two new power transformers, install two new 72 MVA distribution busses, carry out civil work including building expansion, and complete the requisite HV connection work. More specifically:

- This project would involve construction of a new facility on Hydro One property to a downtown residential area and urban parkland, giving rise to a host of potential challenges in terms of obtaining community acceptance and municipal approval.
- This option cannot be executed in time by 2024 to facilitate load transfers , relieve heavily loaded busses and enable near-term customer connections (including DER connections) in the downtown area, due to the extensive civil construction and equipment installation as well as coordination with Hydro One that are required.
- This option is estimated to cost $90 million (see Table 24 for cost breakdown), including required contributions to Hydro One. This estimate would be subject to significant uncertainty given the project scope will include complex work on the transmission system that is yet to be determined and scoped.

Table 24: Cost Breakdown of Esplanade TS expansion ($ Millions)

Item	Cost
Building Expansion	20
Transformers x2	20
Switchgear (Contribution to Hydro One) x2	26
Service Busses x2	14
Civil egress	10
Total Cost	**90**

4. Option 4: Load Transfers

This option includes the installation of feeder ties between busses within the same or different stations and significant civil construction to enable load transfer from heavily loaded busses. For this solution to work, the load receiving bus must have sufficient capacity and feeder positions to accept the new load. Furthermore, for inter-station load transfer, it must be feasible to construct the necessary distribution infrastructure to permanently transfer the load.

Given these requisite conditions, there are various technical barriers that would make this a costly and extremely complex option for 13.8 kV downtown core stations, which include:

- Most downtown station busses are heavily loaded (as shown in Table 7) and thus unable to accept intra- or inter-station load transfer.
- As shown in Table 7, spare feeder positions are increasingly scarce at certain stations as Toronto Hydro continues connecting new customers.
- The downtown core distribution system was not designed with the capability to transfer load through switching operations. Much of the load to be transferred in downtown stations (i.e. secondary network load and large office or condo buildings) comes in discrete chunks that cannot be further divided, and requires dedicated feeder positions. The busses that have capacity may not have sufficient feeder positions available to provide the dedicated feeders needed to supply these discrete loads. For example, if Bus A is overloaded and Bus B has 10 MVA in spare capacity, and the smallest discrete chunk of load on Bus A exceeds 10 MVA, Bus B cannot be utilized to offload Bus A.

As mentioned in Section E7.4.3.1, the City of Toronto's long term Precinct Plans[29] forecast 208 MVA of incremental load over or shortly after the 2020-2024 period in the downtown core. In addition, Table 7 shows the need for spare feeder positions to enable connection of new downtown customers. This option is not a technically feasible alternative to meet these medium to long term needs.

E7.4.5.2 Options for Hydro One Contribution

1. **South-West Toronto System Need – Alternatives Evaluation**

a. <u>Option 1: Do Nothing</u>

Do nothing is not a feasible option as it does not provide the necessary load relief and feeder positions required at Manby TS.

[29] *Supra* Note 2

b. Option 2 (Selected Option): Expansion of Horner TS

This option involves the expansion of Horner TS to provide an additional 192 MVA capacity in the Manby TS and Horner TS service areas. The project scope includes the installation of two 75/100/125 MVA power transformers, four transformer breakers, one bus-tie breaker, 12 feeder breakers with up to six tie switchgears, and up to two capacitors with breakers. As Horner TS is a Hydro One-owned station, the work will be completed by Hydro One. Toronto Hydro submitted a formal Connection Application to Hydro One in 2013 to assess the cost and feasibility of this option. Further, an engineering study performed by Hydro One concluded that this option is technically feasible. The planned in-service date for Horner TS expansion is 2020. Civil infrastructure enhancement work within the Hydro One yard is planned to be completed by 2023. Further project details and benefits are set out below:

- The Manby and Horner TS service areas border Etobicoke creek and the Alectra utility service area on the west, Lake Ontario on the south and Humber River on the East. Toronto Hydro will address these distribution challenges in the detailed design and build civil infrastructure as required.
- The project will help relieve Manby TS, which is expected to reach 100 percent station capacity and become overloaded late in the 2020-2024 period.
- The project will provide additional feeder positions to enable the connection of large new customer connections, including large DER, in the Horner TS service area in the medium to long term.

c. Option 3: Load Transfer to Richview TS

This option would utilize spare capacity at Richview TS, a Hydro One owned station, to relieve the heavily loaded Manby TS, which is located approximately 8 kilometres from Richview TS feeders. This is a significant distance to run 27.6 kV distribution feeders, especially due to physical obstacles and barriers that require crossings such as railway corridors and cables cutting through treed areas. The estimated cost of this option is $77 million, which is subject to significant uncertainty due to the aforementioned challenges. Moreover, running overhead feeders along residential areas would affect the overall aesthetics of the neighbourhood. Another option would be to run underground cables; however, that will require additional civil infrastructure to be built at even greater cost. Lastly, this option will not add additional capacity at the transmission level.

d. Option 4: Build new TS near Manby TS

This option involves Toronto Hydro purchasing land near Manby TS and building a new TS. This new TS would provide at least 100 MVA in capacity to support the long-term growth of the Manby TS and Horner TS service areas. Toronto Hydro performed a feasibility study in 2014 to identify suitable sites for such a new TS and the associated cost. The study concluded that this option would entail a lengthy approval process and long lead times, and may not be implemented in time to help relieve the highly-loaded Manby TS. Moreover, the estimated cost to building a new TS near Manby TS is approximately $72 million, four percent higher than the chosen option ($69.2 million).

2. Hydro One Transformer/Bus Upgrades – Alternatives Evaluation

a. Option 1: Do nothing and Hydro One replaces its transformer/bus like-for-like.

Under this alternative, Toronto Hydro would not have to bear any costs over the forecast 2020-2024 period. When Toronto Hydro determines that additional capacity or feeder positions are required, Toronto Hydro would be responsible for the entire replacement cost of both the transformers supplying the bus and/or the bus upgrade, which is estimated at $30 million. This option is not preferable given: (i) the relatively low incremental cost of the upgrade at this time; and (ii) the likelihood of additional capacity being required in the medium to longer term.

b. Option 2 (Selected Option): Request that Hydro One replace existing transformers with a higher MVA rating unit or add new feeder positions; and contribute to the incremental cost.

The preferred option is requesting that Hydro One replace existing transformers with a higher MVA rating unit or add new feeder positions, and contributing to the incremental cost. In this case, Toronto Hydro would be responsible for the incremental cost difference for the capacity upgrade or addition of new feeder positions. Given the long-term need for additional capacity, this represents an opportunity to align Toronto Hydro plans with Hydro One plans. As a result, capacity would be increased when the other transformer paired with the upgraded transformer is upgraded as well in the future.

The total estimated cost to Toronto Hydro is $10.2 million for transformer upgrades and for replacing existing EOL breakers and adding new feeder positions, with an avoided cost of $20 million as set out in detail below (this avoided cost excludes the costs avoided for breaker replacements). Additionally, when Hydro One is replacing a transformer, the incremental cost of installing a larger unit is relatively small in relation to the incremental capacity derived from the investment, resulting in considerable savings per MVA of additional installed capacity. Table 25 below shows the typical difference between replacing a 75 MVA transformer with a like-for-like transformer versus a higher rated 100 MVA transformer.

Table 25: Cost difference between 75 MVA vs 100 MVA Transformer Installation

Job	Like-for-Like Replacement	Higher Rating Replacement	% Difference
Capacity	75 MVA	100 MVA	25%
Transformer Replacement Cost	$2.5 M	$2.8M	9%
Cost per MVA	$33,333	$27,500	(18%)

E7.4.5.3 Options for Local Demand Response

1. Option 1: Do nothing

Without Local DR, the identified stations, Cecil TS and Basin TS, could be exposed to some operational and reliability risks as early as 2022. Failure to implement Local DR could result in:

- Reduced reliability;
- Costly short-term load transfer projects;
- Reduced flexibility to schedule maintenance outages;
- Inability to accommodate distributed generation (e.g. CHP, solar); and,
- Increased risk of equipment failure, and inability to connect new loads.

Not addressing the identified station constraints and highly-loaded station busses puts the system at risk of violating design parameters, which could result in rotating blackouts and voltage reductions. Lack of spare capacity limits Toronto Hydro’s ability to perform planned maintenance and increases the likelihood of customer outages.

Further, without pursuing Local DR at Cecil TS and expanding the program to include Basin TS, Toronto Hydro would lose a valuable opportunity to build relationships with large and residential customers through this program, mitigate short- and long-term electricity rates, and cost-effectively accommodate new customer connections in the medium-term.

2. Option 2 (Selected Option): Implement Local DR Program as Proposed

Local DR includes programs and technological solutions that encourage load curtailment and load-shifting, allowing for capacity constraints to be addressed over the medium-term (i.e. 5 years) using targeted deployment of DR. Local DR enables the deferral of asset upgrades and optimization of capital allocation.

This option supports the goals of the IRRP, LTEP, the Conservation First Framework, and Ontario's greenhouse gas emissions reduction targets. It also entails partnership/relationship building to not only help resolve medium-term capacity issues but also more effectively leverage load-reduction activities already taking place by the private sector. It represents an opportunity for a win-win arrangement between the utility and its customers.

While stations expansion activities could solve the capacity issues at the identified stations, Toronto Hydro would lose the opportunity afforded by Local DR to mitigate customer rates and to cost-effectively accommodate new customer connections in the short-to-medium-term. (See sub-section five for cost-effectiveness comparison relative to wires alternative.)

3. Option 3: Conventional station capacity expansion

Foregoing Local DR in favour of additional station expansion at the identified stations is a more expensive alternative due to the need for property purchase and project design. This option is expected to cost $57 million for Cecil TS and $78 million for Basin TS. Table 26 and Table 27 set out the relevant high level cost breakdowns.

Cecil TS has no room for additional capacity due to land restrictions. Further, installing new transformers in the Cecil TS area would not increase capacity as they are limited by applicable bus ratings and the existing busses are already overloaded. A wires solution would involve Toronto Hydro acquiring a new building in the area and installing new switchgear to transfer load from Cecil TS to new busses. A wires solution at Basin TS would require significant construction to expand the building and the acquisition of new transformers, busses, and switchgear.

4. Cost Breakdown

As outlined in Table 26 and Table 27 below, the total cost of the conventional investment under this option is expected to be $135 million. Based on the 2017 10-Year Station Load forecast, this spending could be deferred to the late 2020s through local DR strategies.

Table 26: Cost Breakdown of Wires Solution at Cecil TS ($ Millions)

Item	Cost
Property and Building Acquisition	19
Switchgear	13
Transformer and Cabling	13
Civil Construction and Feeder Transfers	11
Project Management & Ancillary	1
Total	**57**

Table 27: Cost Breakdown of Wires Solution at Basin TS ($ Millions)

Item	Cost
Building Expansion	10
Transformer x2	20
Switchgear (Contribution to Hydro One) x2	26
Service Busses x 2	14
Civil Construction Work	6
Project Management & Ancillary	2
Total	**78**

5. Cost-effectiveness

To analyze the cost-effectiveness of applying Local DR at a station, Toronto Hydro used a financial model developed by ICF international for evaluating the business case for DR initiatives. The model was explicitly designed to support Ontario LDCs in making the decision to use Local DR for the purpose of distribution system asset upgrade deferral. It assesses the value of such deferral for the ratepayer, the utility, and the Province.

The model incorporates a series of cost-effectiveness tests that assess the business case and financial impact of Local DR from the perspective of all stakeholders (e.g. ratepayer, utility, Province, program participants). The choice to use this external model was based on the fact that it captures the avoided transmission and generation costs that result from the use of Local DR. The applicable tests are outlined in Table 28 below. Each test assesses the ratio of benefits to costs, and thus the higher the number, the more cost-effective the program is from the perspective of each stakeholder.

1 **Table 28: Definition of Cost-effectiveness Tests used to assess the benefit of Local DR over**
2 **conventional wires solutions**

Test	Perspective	Purpose
Total Resource Cost Test ("TRC")	All ratepayers	To assess the long-term rate impact associated with using DR measure over supply-side option. Accounts for the deferral of local distribution and transmission asset upgrades.
Program Administrator Cost Test ("PAC")	In this case, the LDC	To assess whether DR is cost-effective to administer as compared to supply-side options
Participant Cost Test ("PCT")	Ratepayers participating in Local DR	To assess whether participating in the program will yield more benefits overtime for the participating ratepayers than it will cost them, accounting for any cash incentive, bill credit or direct-install they will benefit from when they sign up in the program and/or as they stay in the program
Rate-Impact Measure Test ("RIM")	Non-participating ratepayers	To asses if rates will go up in the short term as a consequence of Local DR being preferred to supply-side options to refund incentive being handed out, program administration cost, and lost revenues; accounting for the deferral of local distribution and transmission asset upgrades
Net benefit for distribution under the RIM test ("RIM-d")	Non-participating ratepayers	To asses if the distribution portion of the rates will increase in the short term in relation to Local DR
Local Distribution Company Test ("LDCT")	LDC's shareholders	To asses if utilizing Local DR and deferring the local asset upgrades optimizes the LDC shareholder's capital allocation strategy

3 The cost-effectiveness test results for Cecil TS and Basin TS are outlined in Table 29 and Table 30.

Table 29: Cost-effectiveness Test Results for Local DR at Cecil TS

Test Results	Benefit to Cost ("B/C") Ratio	Net Present Value ("NPV") ($ Millions)
Total Resource Cost Test (TRC)	2.0	6.1
Program Administrator Cost Test (PAC)	1.6	4.5
Participant Cost Test (PCT)	2.0	2.1
Rate-Impact Measure Test (RIM)	1.5	4,1
Local Distribution Company Test (LDCT)	N/A	(5.3)

Table 30: Cost-effectiveness Test Results for Local DR at Basin TS

Test Results	Benefit to Cost ("B/C") Ratio	Net Present Value ("NPV") ($ Millions)
Total Resource Cost Test (TRC)	1.9	3.8
Program Administrator Cost Test (PAC)	1.6	2.9
Participant Cost Test (PCT)	1.9	1.2
Rate-Impact Measure Test (RIM)	1.5	2.6
Local Distribution Company Test (LDCT)	N/A	(3.6)

The results of the cost-effectiveness test show that, overall, Local DR for the purpose of asset upgrade deferral over the next 5 years is cost-effective at both Cecil TS and Basin TS. The Total Resource Cost and Rate-Impact Measure tests are both highly positive, indicating that the use of Local DR to defer asset upgrades will have the effect of lowering rates over the short- and long-term. This means that even ratepayers who are not participating in Local DR will see benefit from its implementation. The Program Administrator Cost Test shows that for both stations, the program is cost-effective in terms of its administration costs as compared to the cost of administering asset upgrades. The Participant Cost Test shows that in both cases, participating ratepayers will benefit overall from Local DR, even when accounting for any costs they may incur (e.g. equipment costs related to enabling DR capability).

Notably, for both Cecil TS and Basin TS, the LDC test yields a negative net present value, which represents the cash value that must be recovered by the LDC to remain "whole" when compared to the wires solution option. By deferring these capital investments, the creation of a new revenue stream and a new component of regulated rate of return are also deferred by Toronto Hydro.

6. Station Selection

The selection of Basin TS for implementing Local DR was based on a ranking system that assessed the following criteria:

- Adequate lead-time to implement DR solution: capacity relief must be approximately 5 years in the future (measure based on busses with above 95 percent loading);
- Difficulty of performing bus level load transfers;
- Limited ability to connect new loads;
- High potential for load growth in area; and
- No wires solution planned: If a wires solution is already planned or underway, consideration is given to the potential role for DR to support the implementation of a wires solution by providing additional flexibility.

Basin TS ranked high amongst the stations that were potential candidates for Local DR. Discussions with the IESO also indicated that providing capacity relief at Basin would also help reduce projected strain on the transmission system. Other stations that were considered include: Dufferin, Strachan, Carlaw, Windsor, Main, Manby, and Duplex. These stations were not chosen because capacity relief is required within the short term, making the use of DR measures inappropriate from a reliability perspective given the need to leave a buffer period in case wires solutions are required (i.e. if DR measures are not adequate for providing required capacity).

E7.4.6 Execution Risks & Mitigation

E7.4.6.1 Copeland TS – Phase 2

The Copeland TS – Phase 2 segment is a large undertaking and involves multiple execution risks, which include:

- Given the complex nature of these projects, a host of inherent planning challenges and risks can impact overall project cost and execution, such as the length of time required to acquire permits;
- Road moratoriums established by the City of Toronto;
- Logistical challenges in delivering electrical equipment into the downtown core; and
- Coordination with distribution planners as well as with third parties.

Toronto Hydro will communicate key lessons learned from past projects to Copeland TS - Phase 2 bidders during the RFP procurement process to mitigate project execution risks. In particular, Toronto Hydro will provide risk information associated with facility conditions and restrictions, logistical and transportation issues, unique specifications of major electrical equipment, and permitting issues.

Financial risks will be mitigated by pursuing a fixed-price, turn-key, EPC contract. A competitive bid process will result in a selection of one general contractor responsible for all the major tasks. This is expected to be completed in 2018.

Quality control risks will be mitigated via the use of reputable third party firms with extensive electrical station construction experience to carry out verification and payment review/billing certification. A consulting engineering firm will be utilized to investigate and resolve emerging site issues and ensure that construction is carried out according to specifications.

E7.4.6.2 Hydro One Contribution

The following risks are associated with the execution of Hydro One contribution projects:

- Schedule depends on Hydro One's ability to execute the work;
- Overall project cost is highly dependent on Hydro One estimates; and
- Additional tasks (such as installation of bus and feeder ties or other safeguard measures to protect Toronto Hydro assets during Hydro One asset replacement) maybe identified during detailed equipment outage planning. If an identified task is performed by Toronto Hydro, it will increase the project's cost for Toronto Hydro.

To mitigate these risks, Toronto Hydro engages in active coordination with Hydro One through bi-monthly meetings and as-required on-site meetings with relevant stakeholders to remain aligned with Hydro One's latest sustainment plans.

E7.4.6.3 Local Demand Response

The Local DR program faces certain unique challenges. However, the utility's experience with the current Local DR program will help inform and establish its future risk mitigation strategies.

Some customer types may not be well suited to DR activities. Depending on the market segments applicable in the station area, a customer mismatch may lead to lower than expected program uptake. For example, through the current Local DR program at Cecil TS, it has become apparent that some institutional customers, such as hospitals, are not ideally suited to conventional DR. Toronto Hydro is currently working with one of the largest hospitals in the area to develop a best practices guide to help encourage this sector's participation. This is expected to be a valuable tool from a customer engagement perspective in the next round of Local DR efforts.

Experience gained through the current Local DR program has enabled more effective stations selection, ensuring that the choice reflects a customer mix that is well-suited to Local DR. Basin TS has a relatively large number of industrial and institutional customers that are well-suited to a DR solution (including, for example, a City of Toronto waste treatment plant that already participates in provincial DR).

Higher-than-expected uptake could lead to budget pressures in terms of customer incentives. To manage this, it will be important to track spending closely and set caps on customer uptake. Storage projects often have upside budget risks due to the cost of exploring and installing the technology, the acquisition of land or space for the battery, and the time requirements for permitting. These budgetary risks can be managed by exploring different storage technologies in partnership with commercial customers who are interested in installing (customer-funded) storage. In the current Local DR program at Cecil TS, there has been significant interest from customers in such smaller-scale storage opportunities, which are made viable through participation in the Large DR program. Budget risk can also be managed by leveraging available external funding opportunities (e.g. the Smart Grid Fund).

Certain highly technical projects (e.g. voltage optimization, battery storage) can take longer than expected to implement. It will be important to manage this timing risk closely to mitigate project delaying risk.

E7.4.7 Regional Planning Needs

The following tables, Table 31, Table 32, and Table 33 (from the IRRP Needs Assessment Report), highlights the emerging needs that have been identified in the Toronto Region since the previous regional planning cycle, and reaffirms the near, medium, and long-term needs already identified in the previous RIP.[30] The tables below also highlight how the Stations Expansion program is expected to address these needs.

Table 31: New Needs identified in the Needs Assessment

New Needs	NA Report Section	Stations Expansion Program
End-of-Life (EOL) Assets	*7.1.1*	See *Table 8*.
East Harbor / Port Lands Area and Basin TS – Transformation Capacity	*7.1.2*	NA report identified this need by around 2025+. Therefore, no projects are included in this Program to address this need.
Load Restoration – C14L+C17L, C5E+C7E, K3W+K1W	*7.1.3*	Transmission network constraint. Not applicable to Toronto Hydro.

Table 32: Needs Identified in Previous RIP

Needs Identified in Previous RIP	NA Report Section	RIP Report Section	Stations Expansion Program
South-West Toronto – Station Capacity	*7.2.1*	*7.2*	Addressed with Horner expansion in 2020-2024 Stations Expansion plan.
Downtown District – Station Capacity	*7.2.2*	*7.3*	Addressed with Copeland TS - Phase 2 expansion in 2020-2024 Stations Expansion plan.
230 kV Richview x Manby Corridor – Line Capacity	*7.2.3*	*7.4*	Transmission network constraint. Not applicable to Toronto Hydro.
Supply Security – Breaker Failure at Manby West & East TS	*7.2.4*	*7.6*	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Leaside Autotransformer – Transformation Capacity	*7.2.5*	*7.10*	Transmission network constraint. Not applicable to Toronto Hydro.

[30] See Exhibit 2B, Section B, Appendix A, B, C, D, and E for Regional Planning Reports.

Needs Identified in Previous RIP	NA Report Section	RIP Report Section	Stations Expansion Program
Voltage Instability of 115 kV Leaside Subsystem	*7.2.5*	*Identified in Central Toronto Area IRRP report – Appendix E*	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Leaside x Wiltshire Corridor – Line Capacity	*7.2.6*	*7.10*	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Manby Autotransformers – Transformation Capacity	*4.2.7*	*7.10*	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Manby West x Riverside Junction – Line Capacity	*7.2.8*	*7.10*	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Don Fleet JCT x Esplanade TS – Line Capacity	*7.2.9*	*Identified in Central Toronto Area IRRP report – Appendix E*	Transmission network constraint. Not applicable to Toronto Hydro.

1 **Table 33: End-of-Life Assets – Metro Toronto Region**

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Fairbank TS: T1/T3, T2/T4 Transformers	*2022-2023*	EOL transformers and other HV equipment are identified at these stations for replacement with similar type equipment of the same ratings (discussed further in Section 7.1.1.1 of NA report).	Current 50/83 MVA transformer is largest 115-27.6 kV standard size.
Fairchild TS: T1/T2 Transformers	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Leslie TS: T1 Transformer	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Runnymede TS: T3/T4 Transformers	*2021-2022*		Proposed 50/83 MVA transformer is largest 115-27.6 kV standard size.
Sheppard TS: T3/T4 Transformers	*2019-2020*		Toronto Hydro determined increase in capacity to larger 75/125 MVA transformer was not required.

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Bridgman TS: T11/T12/T13 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations for replacement with higher rated equipment, and are discussed further in Section 7.1.1.2 of NA report	Included in 2015-2019 Stations Expansion plan.
Charles TS T3/T4 Transformers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.
Duplex TS: T1/T2 Transformers	*2023-2024*		Included in 2020-2024 Stations Expansion plan.
Strachan TS: T12 Transformer	*2020-2021*		Included in 2015-2019 Stations Expansion plan.
Bermondsey TS: T3/T4 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.3 of NA report.	Identified as consideration for downsizing, therefore Not Applicable to Toronto Hydro. See section 7.1.1.3 of NA report for details.
John TS: T1, T2, T3, T4, T6 Transformers and 115 kV breakers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.
Main TS: T3/T4 Transformers and 115 kV line disconnect switches	*2021-2022*		Included in 2015-2019 Stations Expansion plan.
Manby TS: T7, T9, T12 Autotransformers, T13 Step-Down Transformer and rebuild 230 kV yard	*2024-2025*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV C5E/C7E Underground Cable: Esplanade TS to Terauley TS	*2024-2025*	EOL Line section is identified for replacement with similar type equipment, and is discussed further in Section 7.1.1.4 of NA report.	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV H1L/H3L/H6LC/H8LC: Bloor Street JCT to Leaside JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV L9C/L12C: Leaside TS to Balfour JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.

E8 General Plant Investments

E8.1 Control Operations Reinforcement

E8.2 Facilities, Management, and Security

E8.3 Fleet and Equipment Services

E8.4 Information Technology and Operational Technology System

E8.1 Control Operations Reinforcement

E8.1.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): N/A	**2020-2024 Cost ($M):** 40.2
Segments: Control Operations Reinforcement	
Trigger Driver: Operational Resilience	
Outcomes: Reliability, Safety, Customer Service, Public Policy	

The Control Operations Reinforcement program (the "Program") will increase Toronto Hydro's operational resiliency and improve the utility's ability to safely operate the distribution grid by creating a fully functional dual Control Centre at its [redacted] work centre. The dual Control Centre at Toronto Hydro will be designed to withstand evolving hazards and threats, deliver reliable electricity, and support the capability to restore electricity as efficiently as possible.

Toronto Hydro's existing Control Centre is a critical infrastructure that acts as a control authority and real-time operator of the distribution system within the City of Toronto. Control Centre operations are hosted from Toronto Hydro's 500 Commissioners work centre and include the following two primary responsibilities:

1) maintain real-time control of Toronto Hydro's distribution plant through telemetry and remote operation of station breakers and field devices; and
2) coordinate all activities involving field crew workers within the "safe limits of approach" to Toronto Hydro plant that is energized above 750 Volts, as prescribed by the Ontario Electrical Safety Code and Electrical Utility Safety Rules.

Failure of Toronto Hydro's existing Control Centre can have substantial financial and economic consequences for Toronto, the largest city in Canada, the fourth largest in North America, and the economic and financial centre of the country.

The proposed dual Control Centre at [redacted] will replace the existing back-up Control Centre at Toronto Hydro's [redacted] location and will be used to operate and control Toronto Hydro's distribution grid in parallel with the primary Control Centre. [redacted]

[redacted]

The development of a dual Control Centre will allow Toronto Hydro to more effectively safeguard, manage, and operate its distribution system, minimize potential safety hazards to the public and employees, and minimize business interruption impacts on its customers, should the primary Control Centre be compromised.

As energy policy changes, bringing innovation and new technology, the evolution of the smart grid is changing the value proposition of Control Centres. Control Centres are becoming more integrated with the technology, not only from a monitoring and control of energy delivery perspective but also from an energy management perspective, elevating their role and importance. The growth of distributed generation has also given distributors some of the reliability responsibilities traditionally reserved for transmission utilities.[1] [redacted] As such, as part of the Program, Toronto Hydro intends to build its dual Control Centre with the technology required to manage this growing system requirement.

In addition, over the last five years, Toronto Hydro's operations have been disrupted by several large-scale environmental and other hazard events. These large scale environmental and hazard events are becoming increasingly more common within Toronto Hydro's service territory and across the industry.[2] For instance, in 2018 alone, Toronto Hydro has experienced four severe weather-related events that caused wide-spread damage and outages.[3] Further, in addition to more frequent and severe weather events, there continues to be an escalation of terrorist attacks on people and property, cyber terrorist attacks, as well as system attacks from increasingly sophisticated hackers. The impact of these events on the distribution system has already been experienced in Ukraine, as demonstrated by the 2015 cyber-attack on three separate distribution companies where continuity

[1] London Economics International LLC, Jurisdictional Review and Economic Case for a Dual Distribution Control Center in Toronto Hydro Territory (June 22, 2018), at p. 15.
[2] AECOM Environment, Toronto Hydro-Electrical Systems Limited Climate Change Vulnerability Assessment filed in EB-2014-0116, Toronto Hydro-Electric System Limited, Exhibit 2B, E8.8, Appendix A (Filed July 31, 2014, Updated February 6, 2015).
[3] See Table 6 for examples of recent severe weather events in Toronto.

of service was disrupted for up to 225,000 customers.[4] Canada is not immune to such threats. Public Safety Canada issued a report titled "The 2017 Public Report on The Terrorist Threat to Canada" indicating that since 2014, Canada's terrorism threat level is Medium, meaning that a violent act of terrorism could occur.[5]

Toronto Hydro has examined its existing operational capabilities in light of these emerging challenges and needs. The plans contained in this Program address the shortcomings of Toronto Hydro's current back-up Control Centre. To assess Toronto Hydro's investment in a dual Control Centre, the utility retained London Economics International ("LEI") to undertake a review of comparator utilities with fully functional dual control centres as well as an economic analysis determining whether this investment is justifiable, see Appendix A.[6] LEI found that utilities expressed similar rationales for requiring a dual control centre, including supporting resiliency, increasing reliability, and ensuring quick recovery from terrorist threats and natural disasters, for example earthquakes, storms, and floods.[7] LEI also found that the growth in distributed energy resources, as is the case in Toronto, has caused distribution utility operations to be more complex and take on some of the traditional responsibilities associated with the Bulk Electricity System, including managing interconnected generation and greater responsibility over bulk system reliability.[8] The review concludes that based on the estimated cost of an outage, the investment in a dual control centre can be economically justified if it can reduce the duration of such an outage.[9]

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[4] Electricity Information Sharing and Analysis Center, White Analysis of the Cyber Attack on the Ukrainian Power Grid (March 18, 2016) at p. 1, found at <https://www.nerc.com>.
[5] 2017 Public Report on the Terrorist Threat to Canada (December 17, 2017), found at <https://www.publicsafety.gc.ca/cnt/rsrcs/pblctns/pblc-rprt-trrrst-thrt-cnd-2017/index-en.aspx>.
[6] Supra note 1.
[7] Ibid at pp. 5-14.
[8] Ibid at p.16.
[9] Ibid at pp. 24-26.

E8.1.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Reducing the likelihood of a complete or partial stand-down of field work and the likelihood of cascading outages resulting from interruption to visibility over the distribution system; and ○ Ensuring compliance with requirements relating to system restoration planning outlined in Chapter 5, Section 11 of the Market Rules.
Safety	• Contributes to Toronto Hydro's safety objectives as measured by Total Recordable Injury Frequency ("TRIF") by: ○ Providing seamless visibility over the distribution system, thereby reducing the likelihood of worker/public injury resulting from loading issues and inadvertent energizing of equipment; ○ Ensuring efficient administration and application of the Toronto Hydro Work Protection Code; and ○ Maintaining compliance with Ontario Regulation 22/04 (Electrical Distribution Safety) through timely reporting of serious electrical incidents involving Toronto Hydro plant.
Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Ensuring continued capability to receive and respond to trouble calls from customers and/or external stakeholders; ○ Maintaining the capability to effectively manage, prioritize and resolve multiple concurrent system issues impacting customers; and ○ Providing relevant and timely outage information to customers, such as estimated outage restoration times and other situational information relating to system outages.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by consistently meeting OEB-mandated service quality targets with respect to Emergency Response (Distribution System Code, s. 7.9).

E8.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Drivers	Operational Resilience
Secondary Driver(s)	Reliability, Safety

E8.1.3.1 Program Drivers

The primary driver for the Program is Operational Resilience and the secondary drivers are Reliability and Safety. As discussed below, the Control Centre is the control authority for Toronto Hydro and is the real-time operator of Toronto Hydro's distribution system. The Control Centre executes most of the critical functions required to successfully operate the distribution system. [redacted]

[redacted]

Table 4: Minimum Space Requirements for a Control Centre – [redacted]

	500 Commissioners	[redacted]	Gap (%)
Control Room Space Requirements (ft^2)	[redacted]	[redacted]	[redacted]

In November 2017, Toronto Hydro Power System Controllers executed a pilot whereby part of the distribution grid would be controlled entirely by the [redacted], as part of an effort to simulate the loss of the primary Control Centre. Within the scope of this pilot, key systems that are required to maintain full operational control of the system were identified as follows:

[redacted]

[redacted]

[redacted]

Table 5: Summary of Technological Restrictions at [redacted] Facility

	500 Commissioners	[redacted]	Gap (%)
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			

[redacted] Orders to Operate (“OTO”) are the final output of the system operation planning process to the field staff to receive step by step instructions on real time operation of equipment from Power System Controllers. These include orders which are executed in sequence to isolate, de-energize, and ground work areas to make them safe for work, change system state, test continuity, hipot test, and restore power. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] the primary Control Centre located at Toronto Hydro's 500 Commissioners site may be vulnerable to certain hazards, such as extreme weather events. Since the primary Control Centre is located within the flood plain, the most probable and consequential hazard or threat [redacted] The flooding is most likely to cause catastrophic damage to the building and various facilities that house the primary Control Centre, [redacted]

As discussed above, Canada's current terrorism threat level is "Medium," meaning that a violent act of terrorism could occur.[10] [redacted] Electrical hazards are, to a large extent, limited through constant system oversight via Control Centre operations.[11]

[redacted]

Moreover, with the introduction of renewable and other distributed energy resources, the nature of Control Centre operations continues to evolve. The growth of distributed energy resources has led to utilities being required to manage bi-directional flow of electricity, managing more complex operations and taking on increasing responsibility that has traditionally been reserved for transmission utilities.[12] This evolution changes the manner in which the power is managed and delivered throughout the grid. With the forecasted increase of distributed generation connections, which is expected to reach 800MW by the end of 2024, Toronto Hydro requires real-time monitoring and control in order to ensure distribution system safety and the adequate management of distributed energy connections.

Lastly, as part of its report, filed at Appendix A, LEI completed a review of various utilities in North America that have distribution operations with more than one Control Centre. These facilities were fully functional and were able to take over full operational functions from the primary Control Centre. The review confirms that utilities serving a critical load in North America invest in more than one fully functioning Control Centre to support resiliency, increase reliability, and ensure quick recovery

[10] Supra note 4.
[11] See Exhibit 4A, Tab 2, Schedule 7, for a discussion of the roles and responsibilities of Power System Controllers.
[12] Supra note 1 at p. 15.

from terrorist threats and natural disasters, for example earthquakes and floods. These same justifications are driving the need for Toronto Hydro's dual Control Centre.

E8.1.3.2 Control Centre Operations & Criticality

The Control Centre's Power System Controllers coordinate and monitor the safe distribution of electricity across Toronto Hydro's service territory and support most of its crtical functions. Power System Controllers maintain real-time control of Toronto Hydro's distribution plant and coordinate all activities involving field crew workers. This real-time control includes monitoring of grid operation, system loading, and response to system or asset failures.

[redacted]

Under normal operating conditions, Power System Controllers prepare and execute OTO (switching instructions), enabling planned capital, and operation and maintenance activities for Toronto Hydro's workforce. Control Centre personnel are involved in developing necessary OTO, dispatch of crews, and conducting isolation and switching functions for each capital construction project or maintenance task that is being performed in order to enable a safe work zone. Each OTO comprises a list of switching instructions which enable operations crews to safely transfer customer load and/or establish suitable work protection over a specified range of system devices, which, in turn, allows crews to work in accordance with applicable safety legislation and protects the security of supply to Toronto Hydro's customers. Work involved in the development of OTO is extremely detailed, drawing on multiple system records in conjunction with current system state/loading and is critical to crew and public safety. Where restoration is not possible, crews work directly with the Control Centre to switch equipment in order to restore power to the extent possible prior to continuing with the root cause.

During abnormal system conditions, which are typically caused by extreme weather events, defective equipment, or heat stress to distribution assets, Power System Controllers coordinate Toronto Hydro's response to these system contingencies. During the abnormal system conditions, the restoration efforts must be undertaken immediately as these conditions might pose a significant safety hazard. The emergency activities might include quick and safe restoration of the downed conductors, failed equipment, electrical/vault fires, environmental hazards and etc. Power System Controllers and Trouble Dispatchers direct the response efforts of Toronto Hydro's Grid Response (emergency maintenance) crews during system contingencies and abnormal conditions.

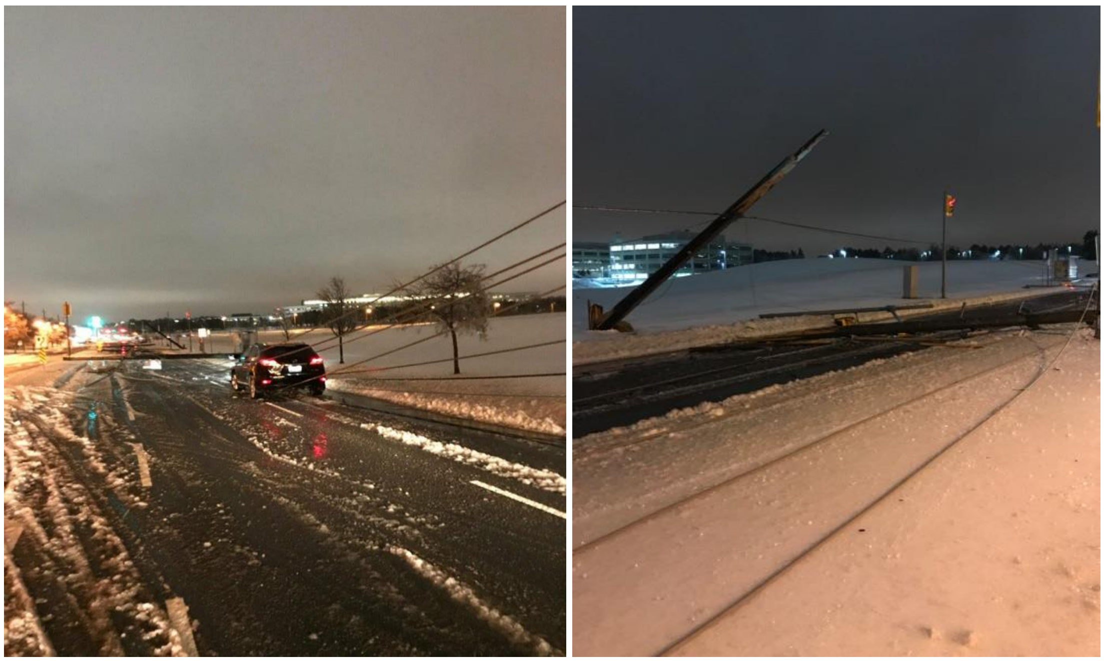

Figure 2: Damage from City of Toronto Ice Storm in April 2018

Toronto Hydro has defined a list of critical functions that are necessary for successful operation of the distribution system. A more detailed description of each these functions is provided in Appendix B. Notably, a number of these critical functions have a maximum tolerable downtime of zero hours.

The North American Electric Reliability Corporation ("NERC") have issued directives and rules concerning the "Loss of Control Room Functionality" which ensure continued reliable operation of the Bulk Electric System in the event that a Control Centre becomes inoperable.[13] NERC standards require the facility containing the Control Centre to be resilient enough to survive, to some extent, the hazards and threats it faces. With respect to criticality relative to their purpose or function, the assets that are subject to NERC requirements are similar in nature to Toronto Hydro's assets. Toronto Hydro serves the largest city in Canada and is also the Country's financial and business capital. As

[13] NERC, Reliability Standards for the Bulk Electric Systems of North America, Standard EOP-008-1 and EOP-008-2- Loss of Control Center Functionality (Updated February 15, 2018).

such, given the criticality of Toronto Hydro distribution system, NERC directives and rules are indicative of the measures that must be taken with respect to critical assets, such as the Control Centre.

E8.1.3.3 Continuity of Operations Capabilities

Control Centers_have become increasingly more sophisticated over the past 30 years from simple analogue tone-based telemetry and control based on electromechanical devices to digital electronic monitoring, data acquisition and control. Paper-based records have been replaced with geo-referenced graphical information systems and outage management systems and crew dispatch and coordination can be accomplished through tablets and crew resource management systems. Control Centers have always been considered critical infrastructure for the management of the distribution system mainly for monitoring and control of substations, transformers, and feeders. However, their purpose continues to evolve to support the new smart grid ecosystem, comprising renewable and other distributed energy resources, micro-grids, electric vehicles, and growing interest in energy storage on the system for power quality, off-peak storage, and grid resilience. As this new paradigm comes into focus, the manner in which power is managed and delivered evolves. Smart grid development requires a completely new concept of a smart grid Control Center, one which is not only critical to distribution system management, but also critical to energy management within the City, and ultimately the Bulk Electric System.

LEI, in its review, concludes that as distribution utilities evolve towards more complex operations and greater responsibility for reliability within the bulk electricity system, fully functioning dual Control Centres will become increasingly necessary.[14] See Figure 3, below, for LEI's depiction of industry trends such as distributed energy resources, smart grids, and electric vehicles that will inevitably challenge the traditional role of the distributor. The fundamental shift to managing bi-directional flow of electricity adds a layer of complexity to Control Centre operations necessitating more active involvement in forecasting intermittent generation, energy scheduling or dispatching generation to manage outages.[15]

14 Supra note 1 at p. 15.
15 Supra note 1 at p. 16.

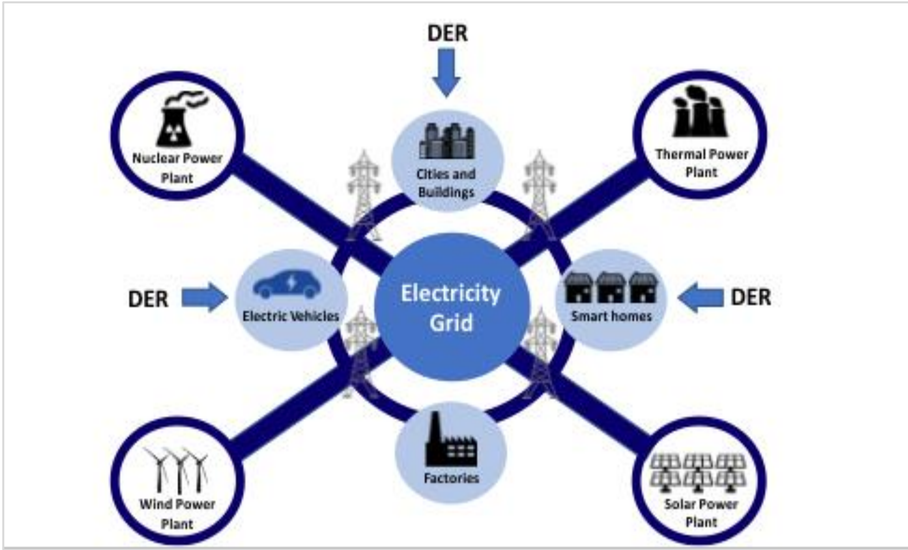

Figure 3: Distributed Energy Resources Interacting with the Electricity Grid[16]

In 2017, Toronto Hydro responded to over 8,000 inquiries from customers and developers seeking to connect generation under various programs. A wide range of proponents have submitted project applications, including many schools, housing managers, large grocery stores, condominium corporations, and department stores. As of the end of 2017, Toronto Hydro has connected over 1,780 Distributed Generators of various sizes representing approximately 225MW. Based on internal forecasts, Distributed Generation connections in Toronto are expected to increase and to reach 800 MW by the end of 2024.[17]

[redacted] As such, as part of the Program, Toronto Hydro intends to build its dual Control Centre with the technology required to manage this growing system requirement. The dual Control Centre will have the capability to monitor and control distributed energy resources. In the event that primary control is lost, it is critical to understand which sources on the system have tripped off, and which have not, both for work protection, but also for power restoration efforts. In accordance with Rule 149 of the Electrical Utility Safety Rules, Toronto Hydro must identify backfeed hazards and eliminate where possible, or control using approved temporary grounding procedures. Although modern inverters

16 Supra note 1 at p. 15.
17 See Exhibit 2B, Section E5.1.

have anti-islanding capabilities, it has been known to fail, and, therefore, do not completely eliminate the back feed hazard, as required by the Electrical Utility Safety Rules.

E8.1.3.4 Risk Exposures

1. Extreme Weather Events

Toronto Hydro evaluates its state of operational preparedness for managing large-scale events on a periodic basis. As part of the evaluation, significant weather events are reviewed along with system resilience, system and customer impacts, and organizational response. Over the last five years, Toronto Hydro experienced several incidents, and some of the more extreme examples include:

- Hurricane Sandy (2012);
- Ice Storm (2013);
- City of Toronto Flooding Event (2013);
- Manby Station Flooding (2013);
- Freezing Rain Event (2017);
- City of Toronto High-water/flooding event (2017);
- Ice Storm (2018); and
- Wind Storm (2018).

Figure 4: Damage from City of Toronto Wind Storm in May 2018

Table 6, below, provides examples of extreme weather events occurring in the first half of 2018 in the City that exceeded Toronto Hydro's standard response practices and triggered the deployment of additional planning and response resources under the utility's Disaster Preparedness Management program.[18]

Table 6: Examples of Recent Severe Weather Events in the City of Toronto

Event	Description
Wind storm (April 2018)	• Sustained 65km/h winds, with gusts approaching 90km/h. • Estimated 24,000 customers out at peak; all customers restored within 48 hours of the end of the event.
Ice storm (April 2018)	• Approximately 10-20mm of freezing rain, 20-25mm rain, sustained winds of 70km/h with gusts up to 110km/h. • Estimated 51,000 customers out at peak. • 99 percent of customers restored within first two days of response; all impacted customers restored within 5 days of the start of the event.
Wind storm (May 2018)	• High winds reported throughout service territory with gusts reaching approximately 120km/h. • Estimated 68,000 customers out at peak. • 96 percent of customers restored within 48 hours of the start of the event
Flash storm (June 2018)	• High winds reported throughout service territory with gusts reaching approximately 90-100km/h. • Estimated 16,500 customers out at peak. • 86 percent of customers restored within the first 12 hours and 97 percent of customers restored within the first 24 hours of the event's occurrence

These events, some of which had significant impacts on Toronto Hydro operations, have highlighted a need for increased emergency preparedness and operational resilience of Toronto Hydro's distribution system. Toronto Hydro's distribution system and facilities continue to be exposed to ever-increasing hazards due to the increase in severe environmental events introduced as a result of

18 See Exhibit 4A, Tab 2, Schedule 6.

climate change.[19] It has been identified that global and regional climate has changed and will continue to change within the City of Toronto, including continued increases in average and extreme maximum temperatures, increases in total annual rainfall, and increases in the intensity of rainfall events.[20]

As illustrated in Figures 5 and 6 below, the 500 Commissioners work centre, which houses the primary Control Centre, is situated along the path of the Don flood plain and is adjacent to Lake Ontario. The last known major flooding disaster – brought on by Hurricane Hazel – occurred in 1953, affecting an extensive portion of Toronto and the Greater Toronto Area ("GTA"), and in particular introducing widespread flooding at the location where the 500 Commissioners facility currently exists. In recent years, including 2013 and 2017, there have been additional flooding events within the City of Toronto, brought on by ongoing climate changes. Global climate change is expected to continue to introduce observable impacts to the environment, including changes in precipitation patterns.[21] [redacted]

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19 AECOM Environment, Toronto Hydro-Electrical Systems Limited Climate Change Vulnerability Assessment filed in EB-2014-0116, Toronto Hydro-Electric System Limited, Exhibit 2B, E8.8, Appendix A (Filed July 31, 2014, Updated February 6, 2015).
20 Ibid.
21 This is a consequences of climate change, see National Aeronautics and Space Administration (NASA), URL: https://climate.nasa.gov/effects/, 2018.

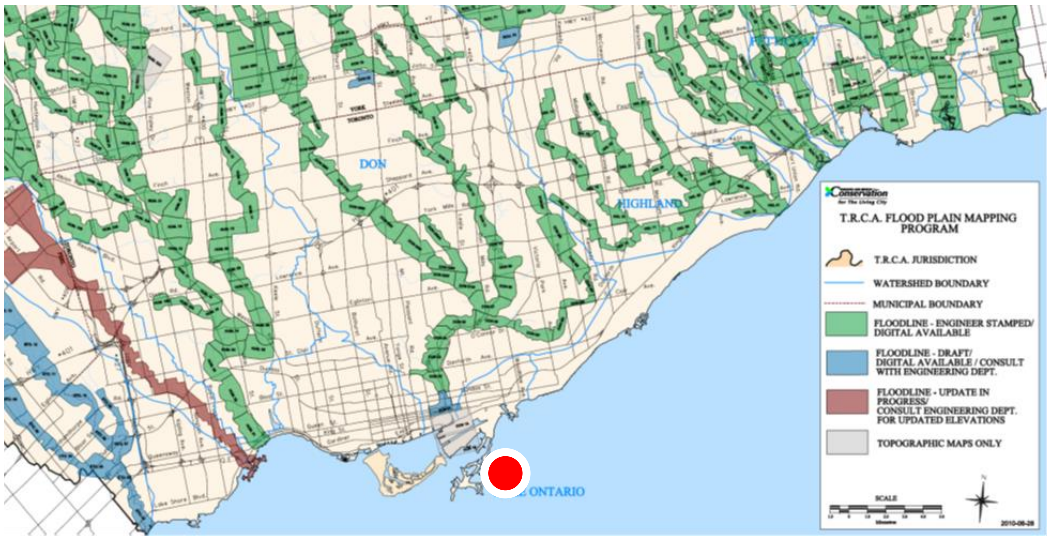

Figure 5: City of Toronto Flood Plain Mapping Program[22]

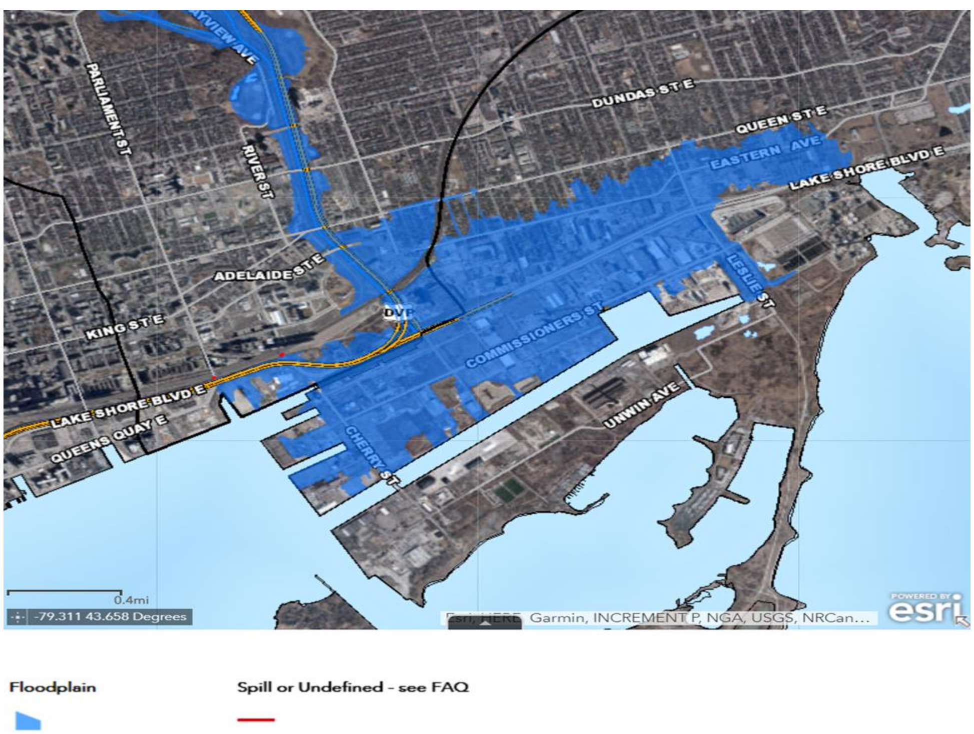

Figure 6: View of 500 Commissioners Street within path of Don Valley

22 The primary Control Centre located at 500 Commissioners is represented by red dot on the map.

Lastly, Public Safety Canada has consistently identified that severe weather poses one of the greatest threats to the Canadian electricity industry.[23] The report specifies that global warming has augmented the risk from natural hazards as it has increased the frequency and intensity of extreme weather events. Indeed, Toronto Hydro's service territory, as well as some of its facilities, have already experienced several weather-related hazard events and further exploration of post-incident reviews has underscored the need for reducing Toronto Hydro's operational risk exposures.

2. Deliberate Threats

In 2017, Public Safety Canada issued a report Canada's terrorist threat levels, in which it discussed the likelihood of a violent act of terrorism occurring in Canada, based on information and intelligence. Canada's current terrorism threat level is "Medium," meaning that a violent act of terrorism could occur, and has been at this level since October 2014."[24] In the same report, Public Safety Canada also identified the potential of cyber security terror attack on essential services, including the electric distribution grid.[25] [redacted]

[redacted] The report further outlines "…terrorist entities aspire to use cyber-tools as weapons that can cause physical harm to computer networks and systems, which would be a far more sophisticated type of cyberattack. Possessing sufficiently advanced capabilities would enable them to successfully disrupt essential services and critical infrastructure (such as the electrical grid).[26]

23 Public Safety Canada, Threats Analysis: Threats to Canada's Critical Infrastructure Report, March 12, 2003 (available at https://www.publicsafety.gc.ca/lbrr/archives/cn000034012674-eng.pdf); Public Safety Canada, National Strategy for Critical Infrastructure Report, 2009 (available at https://www.publicsafety.gc.ca/cnt/rsrcs/pblctns/srtg-crtcl-nfrstrctr/srtg-crtcl-nfrstrctr-eng.pdf)
24 Ibid at p.5.
25 Ibid.
26 Supra note 23 at p.9.

[redacted]

E8.1.4 Expenditure Plan

Toronto Hydro requires $40.2 million over the 2020-2024 plan period to construct a dual Control Centre that will be built with hazard and threat resilience in mind. The expenditure plan for the dual Control Centre is separated into four categories (non-direct construction costs, alterations & demolition, building construction and site works), which spans over a three year period between 2020 and 2022.

Table 7: Forecast Program Costs ($ Millions)

	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**
Non-direct Construction Costs	3.4	2.6	4.8	-	-
Alterations and Demolitions	-	14.1	11.8	-	-
Building	-	0.3	0.6	-	-
Site-works	0.5	0.4	1.7	-	-
Total	**3.9**	**17.4**	**18.9**	**-**	**-**

Work associated with non-direct construction costs begins in 2020 and includes feasibility cost planning, design, and permitting. Deliverables include a detailed drawing package for the dual Control Centre. Once deliverables are finalized, the building permit application process and any Preliminary Project Reviews or Site Plan approval applications with the City of Toronto will commence. A team of experienced project managers will then manage the construction of the dual Control Centre from inception to completion. The construction phases will include regular construction inspections, shop drawing reviews & approvals, payment certifications, and overall construction support. The expenditure plan will conclude in Q4 2022 with closeout document preparations, deficiency reviews, and asset testing and commissioning.

The alterations and demolition expenditure plan will occur in the early phases of construction and will include removal of existing concrete footings & structural steel in preparation for the build out of the second floor. In order to accommodate the installation of large equipment during building construction, the concrete exterior wall will be demolished and replaced with modular louvered wall system. Existing mechanical, electrical infrastructure will also be removed in preparation for new installations.

The majority of the costs in the expenditure plan are for building construction. Architectural plans will be constructed with provisions for the second floor build out, separate mechanical, electrical and IT hub rooms. These provisions will be formed by two storey masonry block walls, concrete foundations, interior wall finishes, and structural steel. Mechanical and electrical equipment will be purchased and installed once architectural components have sufficiently progressed. The mechanical equipment is comprised of HVAC systems used to heat and cool office spaces, plumbing for washroom facilities, air extraction for generator equipment, cooling capacity for IT & UPS rooms, and fire sprinkler systems. The electrical building cost expenditure is a large portion of the building construction costs due to the dual generators and dual UPSs (Uninterruptible Power Supply) that will be installed as per control centre requirements based on TIER 1 utility, TIER 2 generator, TIER 3 UPS and TIER 3 EPS and UPS distribution. As the project progresses into the final years of construction, interior finishes will be installed in the office spaces such as ceiling tiles, carpet, tiling, office furniture, audio visual equipment, and IT hardware.

The expenditure plan for site works will begin once a site plan approval has been granted for the expansion of the parking lot. This will include new asphalt, walkways, curbs, and modification to the storm water management system. Due to site conditions, a retaining wall will be constructed to allow for additional parking spots. Also included in the site works expenditure plan are new light standards and security equipment. This equipment will ensure that the parking lot is appropriately lit during dark hours and employees are safe coming to and leaving the facility.

All of the above details surrounding the expenditure plan for the dual Control Centre comes with potential additional costs due to the construction work occurring in an occupied work centre. Considerations for noise and disruption will have to be taken into account when scheduling construction work. This could result in after-hours work, fire panel bypass, fire watch, and contingencies to maintain business continuity. Contingencies for these items have been included in the construction estimate and represent $1.0 million of the expenditure plan.

E8.1.4.1 Implementation Strategy

The construction of the Control Centre will be managed by Toronto Hydro. The dual Control Centre will be constructed in three stages, as displayed below:

Table 8: Phase One Objectives

Responsibility Group	Description	Proposed Deadline
Toronto Hydro	Develop and procure contracts for construction manager, project management and contract administrator	Q3 2020
Design Team	Complete the design tender drawings	Q3 2020
Design Team	Begin obtaining City approvals in order to proceed with construction (site plan approval, permits, etc.)	Q3 2020
Toronto Hydro	Review and approve design drawing for the Control Centre	Q4 2020

Table 9: Phase Two Objectives

Responsibility Group	Description	Proposed Deadline
All	Once drawing are ready for tender, work with the team to develop project schedule and critical path	Q4 2020
Construction Manager	Tender the construction work	Ongoing
Construction Manager	Begin construction at [redacted] and ensure adherence to the project schedule.	Q4 2020
Toronto Hydro	Procure Furniture / Equipment for Office Space	Q2 2022
All	[redacted] Dual Control Centre's substantial completion	Q3 2022

Table 10: Phase Three Objectives

Responsibility Group	Description	Proposed Deadline
All	Work with team to identify and address all construction deficiencies	Q4 2022
Design Team	Create and deliver close out documentation to Toronto Hydro	Q4 2022
Toronto Hydro	"Go Live" with Control Centre	Q4 2022
Toronto Hydro	Pay all vendors and close the project	Q4 2022

E8.1.4.2 Planned Project Timeline

Table 11: Planned Project Timeline

	2020				2021				2022			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Non-Direct Construction Cost												
Interior Demolition												
Building Construction												
Site work												

E8.1.5 Options Analysis / Business Case Evaluation ("BCE")

E8.1.5.1 Option 1: Status Quo

The status quo option will entail continuing with the existing Control Centre set-up, i.e. the Control Centre located in 500 Commissioners serves as the primary Control Centre, while the facility located in [redacted] serves as the backup Control Centre. There will be no incremental spending to further safeguard the 500 Commissioners location from the threat of flooding or other catastrophic events. Under this scenario, the primary Control Centre would remain vulnerable to severe weather-related events, due to its location that is adjacent to Lake Ontario and along the path of the Don Valley flood plain. [redacted]

E8.1.5.2 Option 2: Fortification of 500 Commissioners Street Work Site

One option in mitigating some of the risks associated with the primary Control Centre would be to introduce enhanced fortification of the current 500 Commissioners facility such that the risk of catastrophic failure is reduced. As described above, the primary Control Centre at Toronto Hydro's 500 Commissioners facility is located along the path of the Don flood plain and is adjacent to Lake

Ontario. This places the facility at a significantly elevated risk of flooding, which would result in the catastrophic failure of the primary Control Centre. There are several methods available in order to safeguard office buildings and structures from potential flooding events. As described by the Federal Emergency Management Agency ("FEMA") within their study "Floodproofing for Non-Residential Structures", recommended actions for safeguarding commercial facilities such as 500 Commissioners include:[27]

- Elevating the existing structure using posts, piles, piers or walls;
- Installation of flood shields and closures; and
- Installation of floodwalls and levees.

However, elevating the current Commissioners structure would be infeasible due to the multiple levels of structure and materials utilized as part of the construction. It would be possible to install flood shields and closures around the primary control centre location, coupled with floodwalls and levees along the entire length of the Commissioners facility that faces Lake Ontario.

Using the suggested cost estimate data provided by FEMA in its Floodproofing for Non-Residential Structures study,[28] coupled with the square footage and dimensions of the 500 Commissioners facility, total costs to perform full flood-proofing of the Commissioners facility are estimated to exceed $10 million. This includes secondary costs including the extension of fibre to support the Control Centre functions, waterproofing of walls and floors, installation of subfloor drainage systems as well as backflow prevention devices and testing of flooding shield systems. These costs do not account for the loss of usable space that may be incurred due to the installation of flood shields, closures, floodwalls, and levees respectively. These costs would only contribute towards the protection of a flooding event. However, other risks (e.g. terrorist attack) and natural disaster events could also compromise the Commissioners location and would not be at all addressed by this option, leaving Toronto Hydro and its customers vulnerable to many of the same risks discussed in the option above.

Furthermore, under this scenario, the backup Control Centre at [redacted] would continue to operate in parallel with the primary control centre. [redacted]

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[27] "FEMA 102: Floodproofing for Non-Residential Structures", Federal Emergency Management Agency, 1986, available at: <https://www.fema.gov>.
[28] Ibid.

[redacted]

For these reasons, Toronto Hydro does not consider fortification of the 500 Commissioners location to be a viable option.

E8.1.5.3 Option 3: Development of a Dual Control Centre at [redacted]

The third option assessed entails the development of a dual Control Centre at [redacted] The subsequent sub-sections will individually examine each facility to assess the feasibility of developing a fully-operational dual Control Centre within.

1. **Option 3.1: Dual Control Centre at [redacted] Work Centre**

[redacted]

[redacted]

2. **Option 3.2 (Selected Option): Dual Control Centre at [redacted] Work Centre**

[redacted]

This location possesses a total of 12,000 square feet of available space to accommodate a fully-functioning dual Control Centre. SCADA and telecom facilities already exist at this location, making this location the most cost efficient for installation and set-up, when compared to other existing facilities. In addition, the facility will be able to perform all operations that can be executed by the primary Control Centre, including monitoring distributed generation and renewable connections.

By far, the greatest advantage of the [redacted] location is that it has the space and other requirements necessary to accommodate a fully functioning dual Control Centre. Employees at both Control Centres will be responsible for different areas of the City, to ensure there is no duplication in work. Since it would be operating in parallel to the primary Control Centre, under an emergency scenario, there will be virtually no impact on operations as the dual Control Centre will be able to resume all functions of the primary Control Centre.

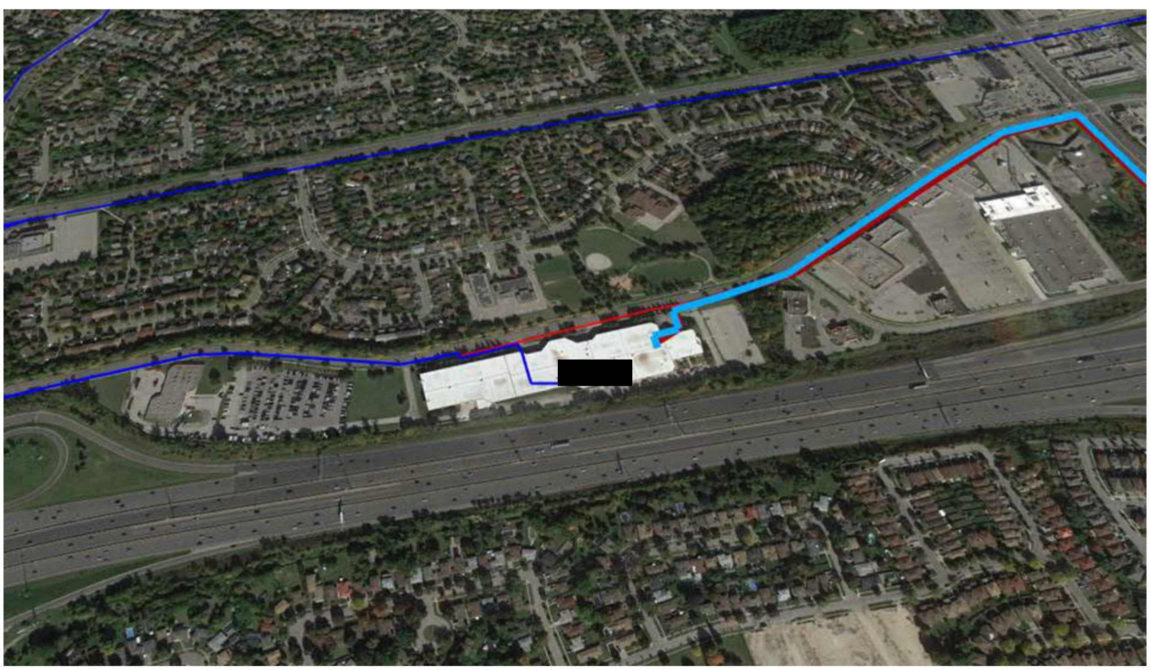


Figure 7: Fiber Cable Routing to [redacted]

3. Option 3.3: Dual Control Centre at [redacted]

It should be stated that many of the advantages associated with the [redacted] location are also associated with their [redacted] location. [redacted]

[redacted]

E8.1.5.4 Option 4: Development of a Dual Control Centre with Limited Functionalities at [redacted]

This option would involve the development of a dual Control Centre with limited functionalities (i.e. not a fully functioning Control Centre) at [redacted] This limited Control Centre would operate in a similar manner [redacted] This option would only be available at [redacted] due to the available space at this location in order to accommodate the requirements, as previously noted above.

[redacted]

[redacted]

[redacted]

While space requirements for this backup facility would be reduced by approximately 50-60 percent when compared to a fully functioning Control Centre, the funding requirements would not be reduced proportionally. This is due to the fact that certain components, such as the Uninterruptible Power Supply, data centre, electrical room, and generators must be fully built at the time of construction. These components cannot be constructed in an incremental manner, even if the Control Centre is utilized only for partial, backup purposes.

E8.1.5.5 Option 5: Development of a Dual Control Centre at a Newly Acquired or Leased Facility

The development of a dual Control Centre at a newly acquired or leased facility would allow Toronto Hydro to select an optimal location of its choice based on a host of considerations, such as risk and cost. This option would allow the utility to custom design a Control Centre to fit all its requirements rather than to design a facility to fit existing infrastructure and space. Since the new location will house all new IT-related infrastructure, it will present a lower risk of failure. In addition, existing Toronto Hydro operations would not be disrupted by construction issues (noise-related or otherwise) since no other Toronto Hydro functions would be co-located on the premises.

However, the utility will incur costs to construct fiber-optic infrastructure to enable SCADA capabilities. There will be added costs of additional support services required for the dual Control Centre at a newly acquired or leased site. For instance, IT personnel will need to be either located within the new site or travel from Toronto Hydro's existing sites to the new Control Centre in case of IT-related issues.

E8.1.5.6 Evaluation of Options

The evaluation criteria used to assess the various options available to Toronto Hydro include the following:

1) Current weather related risks associated with the proposed location (for instance, is it located within the path of a flood plain);

2) Available space within the proposed location (when compared to minimum space requirements for a fully functioning Control Centre);
3) Available technological capabilities within the proposed location (when compared to minimum technological requirements for a dual Control Centre);
4) Impact associated with a terrorist event, and whether the event would prevent the full enablement of the dual Control Centre; and
5) Total cost impact to ratepayers.

Each of the above criteria were taken into consideration when selecting the best overall option for Toronto Hydro.

Table 12, below, illustrates the results of the options analysis, comparison and final recommendations, based upon what has already been discussed for each of the options above.

Table 12: Results of Option Analysis

Criteria / Location	[redacted]	Newly Acquired or Leased Facility
Weather Risks		
Available Space		
Available Technological Capabilities		
Dual Control Centre Enablement		
Impact of Terrorism Attack		
Total Costs		

Legend
Does not meet criteria
Partially meets criteria
Meets or Exceeds Criteria

When assessing current-state risks, availability of space and technological capabilities, costs, as well as overall ability to meet the objectives of dual control centre enablement, this comparison indicates that both the development of a dual Control Centre at [redacted] and at a newly acquired or leased facility satisfies all the criteria. However, the differentiating factor between the two options is cost.

Building a dual Control Centre at Toronto Hydro's existing facility at [redacted] is the most effective solution and the primary reason for why the utility has opted to adopt this approach.

Furthermore, Toronto Hydro performed a comparative analysis of how each of the various Control Centre locations (alternatives considered), including the proposed at [redacted], are equipped to handle critical emergency functions. Appendix B presents the results of these analysis. It must be noted that all of these functions can be supported through the primary Control Centre at 500 Commissioners facility, as well as the proposed dual Control Centre at the [redacted] location. However, notable constraints exist under the current configuration where [redacted] location acts as the backup Control Centre, as described above.

E8.1.6 Execution Risks & Mitigation

The largest risk to the successful execution of the Program involves timing and costs. The expenditure plan is based on estimates of external labour, external labour and material costs over the 2020 to 2022 period. Material costs are generally subject to greater price fluctuations over time and therefore cost-overruns may transpire. However, through the expertise of experienced project management leadership, and industry experts a proactive approach will be taken to manage these costs.

In addition, there are also construction related risks associated with the Program, including:

- Unexpected construction conditions
- Occupational health and safety
- Disruption to Toronto Hydro employees at [redacted]
- Design change approvals
- Budget shortfalls
- City approval delays
- Procurement / Tender delays
- Design changes

These issues can be mitigated with proper communication, leveraging the expertise of the consultants and proper project planning, see Table 13, below. Overall, leading project management tools and practices will be utilized and the expertise of highly qualified project management leadership and industry experts will be leveraged in order to take a proactive approach to managing unknown conditions.

1 **Table 13: Phase One Risk and Mitigation Strategy**

Risk Description	Impact Level	Mitigation Strategy
City Approval Delay	*High*	Leverage the experience and expertise of the design consultants to work with the City to obtain approvals.
Procurement / Tender Delays	*Medium*	Ensure drawings are complete and involve the design team during the tender process.
Design Changes	*Medium*	Toronto Hydro to work internally to limit the amount of changes on the project after tender process.
Unexpected Construction Conditions	*High*	Leverage the expertise of the Design team to ensure that unknown construction conditions are addressed in the most efficient manner.
Occupational Health and safety	*High*	Have a metric in place that tracks safety infractions. Ensure construction manager adheres to Toronto Hydro safety standards.
Disruption to Toronto Hydro Staff at [redacted]	*High*	Ensure proper communication with Toronto Hydro employees. Work that can have high impact on Toronto Hydro employees to occur after hours.
Design Change Approval	*Medium*	Ensure proper process is in place to ensure changes are approved in a timely manner.
Budget Shortfalls	*High*	Develop a budget with some contingency and work with team to ensure value engineered savings.
Major Deficiency Discovered	*High*	Have the design team review the progress of construction regularly to ensure work is completed has per plan
Unpaid invoices	*Medium*	Ensure proper communication with all vendors to ensure they are paid in a timely manner

Jurisdictional review and economic case for a dual distribution control center in Toronto Hydro territory

prepared by London Economics International LLC

June 22nd, 2018

Distribution control centers ("DCC") support reliability, resiliency, and the ability to recover quickly from deliberate attacks and natural disasters. LEI has found that there is a precedent for utilities across North America to build fully functional backup control centers, at similar costs to those proposed by Toronto Hydro. Justifications included increasing reliability and resiliency, with certain utilities citing specific situations such as natural disasters or terrorism threats. Growth in distributed energy resources has also caused distribution utility operations to be more complex and take on some of the responsibilities traditionally required in the Bulk Electricity System, including dealing with interconnected generation and taking greater responsibility for bulk system reliability. LEI believes that the evolution of these responsibilities also support the need for Toronto Hydro's proposed dual DCC. Finally, LEI's analysis indicates that the proposed costs can be justified economically, given the significant costs of outages in the city of Toronto, and the potential for the dual control center to reduce the duration of high-impact outages.

Table of contents

London Economics International LLC
390 Bay Street, Suite 1702
Toronto, ON M5H 2Y2
www.londoneconomics.com

contact:
Ian Chow/Adam Hariri
416-643-6627
ian@londoneconomics.com

Table of figures

Figure 1. List of Acronyms

BEA	U.S. Bureau of Economic Analysis
BUCC	Backup Control Centers
CAD	Canadian Dollars
CECONY	Consolidated Edison Company of New York
DCC	Distribution Control Center
DER	Distributed Energy Resource
EIA	US Energy Information Administration
EMP	Electromagnetic Pulse
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FPL	Florida Power & Light Company
GDP	Gross Domestic Product
HECO	Hawaiian Electric
HMCC	Hardened Mobile Control Center
HVAC	Heating, Ventilation, and Air Conditioning
IESO	Independent Electricity System Operator
ISO	Independent System Operator
ISOC	Integrated System Operations Center
IT	Information Technology
LDC	Local Distribution Company
LEI	London Economics International LLC
LTEP	Long Term Energy Plan
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
PG&E	Pacific Gas and Electric
RDGI	Renewable Distributed Generation Integration
SAIDI	System Average Interruption Duration Index
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas & Electric
TCC	Transmission Control Center
THESL	Toronto Hydro Electric System Limited
TS	Transformer Station
TSX	Toronto Stock Exchange
UPS	Uninterrupted Power Supply
US	United States
USD	US Dollars
VoLL	Value of Lost Load

1 Executive Summary

1.1 Scope of services

LEI was engaged by Toronto Hydro to undertake an independent study of comparator utilities with fully functional backup control centers ("BUCCs") in other jurisdictions. The utilities were reviewed and analyzed in terms of their functionality as well as cost. LEI also considered the proposed dual control center from an economic perspective by estimating economic costs of a high-impact outage on Toronto Hydro's service territory.

1.2 Summary of findings

LEI has identified five utilities that have built fully functional BUCCs— Hydro One, Consolidated Edison, Pacific Gas & Electric, Florida Light & Power, and San Diego Gas & Electric. These utilities identify various justifications for their investment, including supporting resiliency, increasing reliability, and ensuring quick recovery from terrorist threats and natural disasters, for example earthquakes and floods. Integration of Distributed Energy Resources ("DERs") was also cited.

All reviewed BUCCs were fully functional and were able to take over operations from the primary control center. However, different utilities varied in terms of their mode of operation: the number of backups, whether they were manned or unmanned, and whether they ran in parallel or not. Toronto Hydro's current BUCC has only [redacted] of the functionalities of the primary control center; the proposed dual control center is to be fully functional and run in parallel with the primary control center.

In its study of comparator utilities, LEI found that the cost of BUCCs built in the past 5 years are aligned with the cost of Toronto Hydro's proposed dual control center. Moreover, the justifications of costs, and challenges faced by comparator utilities are comparable. Compared to the utilities reviewed, Toronto Hydro serves a uniquely important load in terms of political and economic significance, as well as a large base of customers with significant population density.

LEI also reviewed the impact of DERs on the role of the distribution utility. The growth of distributed generation has given distributors some of the reliability responsibilities traditionally reserved for transmission utilities, such as forecasting and dispatching generation. In California, Texas and Hawaii, as well as Ontario, utilities, regulators and reliability authorities have recognized the threat of high DER penetration to the reliability of the bulk transmission system. Bulk system utilities are governed by NERC safety requirements, including the requirement for backup functionality of its control center. LEI believes as distribution utilities evolve towards more complex operations with greater responsibility for reliability, fully functional backup distribution control centers will become increasingly necessary.

Finally, LEI conducted a high-level review of the economic cost of a high-impact outage on Toronto Hydro's service territory, which covers the financial and economic capital of Canada. Extraordinary events such as natural disasters or terrorist attacks could cause the inability to operate Toronto Hydro's primary control center, resulting in delayed service recovery time following an outage. LEI's analysis shows that the proposed costs for the dual control center can be justified economically, given the significant costs of outages in the city of Toronto, and the dual control center's potential to reduce the duration of these outages.

2 Role of distribution control centers

Electricity distribution control centers ("DCCs") are used to control, coordinate, and monitor the distribution of electricity. Utilities in North America are upgrading their control centers to support reliability, resiliency, and to recover more quickly from natural disasters – and in order to further increase reliability, some utilities have built fully functional BUCCs.

DCCs provide real-time management of the grid. Supervisory Control and Data Acquisition ("SCADA") systems are used to obtain data about the distribution system via sensors and operate station breakers and field devices to manage the system. From the DCC, operators are able to monitor grid operation, manage planned and unplanned outages, manage system loading, as well as determine areas to improve grid performance and reliability. Key tasks at a DCC include clearance management and developing switching orders for planned maintenance.[1] Clearance management is the process by which the DCC determines periods that equipment can be taken out of service by asset management for planned work. Operators need to consider the outage length, system conditions and other clearance requests to determine when clearance can be taken. After clearance is approved, a switching order must be developed, which involves deenergizing equipment before any work is performed for safety, as well as reconfiguring the power system to perform reliably during this period. These responsibilities are critical to enable the reliable operation of the distribution system and ensure the safety of the public and utility employees.

Given their important role, DCCs are typically set up to run on a 24/7 basis with multiple levels of redundancy. Electrically they may be supported with an uninterrupted power supply ("UPS"), battery storage and/or a backup diesel generator, while SCADA systems will have multiple communication feeds, and technology systems will be designed to withstand application or hardware failures. BUCCs are used as a type of physical redundancy, where utilities have a separate facility that can take over the responsibilities of the primary DCC, if the primary DCC is inoperable or inaccessible.

Hot vs. Cold Backup Control Centers

Redundancy in BUCCs can be applied in various ways. Cold BUCCs are secondary backups that are only called upon when the primary system experiences a significant failure. Hot backups are a method of redundancy in which both primary and secondary systems are running, so that the secondary BUCC is receiving and processing the same information so that it can assume operations quickly and smoothly.

3 Control center operations in other jurisdictions

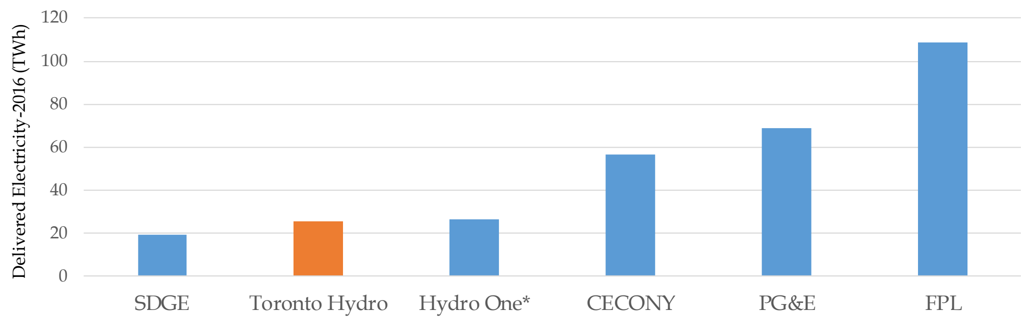
This section provides case studies of control centers in other jurisdictions, all of which are for utilities that have distribution operations. These utilities have sought to bolster their backup plans

[1] Vadari, Mani. *Electric System Operations: Evolving to the Modern Grid*. 2013.

to improve reliability and resiliency against severe weather events such as hurricanes and floods, as well as attacks including cyber-attacks.

LEI reviewed large Canadian and US utilities and identified four utilities that publicly disclose they utilize fully functional BUCCs to improve reliability in their distribution operations.[2] Hydro One has also been included, as they are developing a new 'dual primary' control center to replace their current BUCC, as discussed in its most recent distribution rate application.

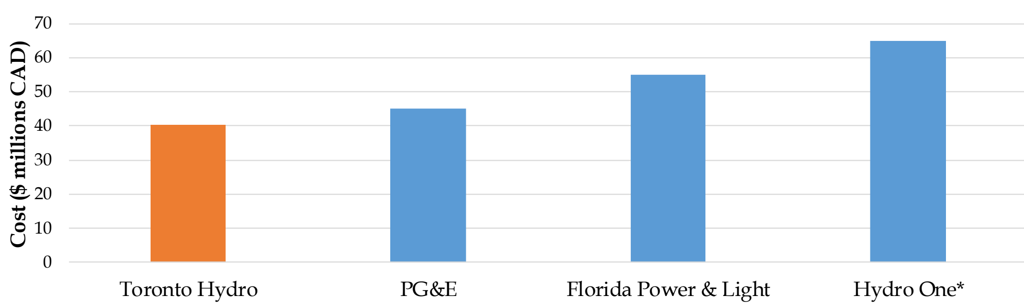
Figure 2. Electricity delivered by utilities



* Note: Electricity delivered to Hydro One distribution customers only
Source: Company reports and websites

In terms of the capabilities of the backup controls centers, all five case studies are fully functional and can completely take over operations from the primary control center. Toronto Hydro has estimated that the existing BUCC at [redacted] of the functionalities of the primary control center. Toronto Hydro's proposed dual control center at [redacted] would be fully functional, and costs are in line with (and slightly lower than) the identified utilities that had publicly available control center construction costs. A comparison of costs is shown below in Figure 3.

Figure 3. Control center construction costs



[2] LEI reviewed the 20 largest US utilities and 5 largest Canadian distribution utilities by number of customers. The excluded utilities may also use a backup control center, however were excluded from this review as no public information was found.

* Note: Budget of distribution portion of control center only, not the total cost

A comparative summary of the profiles and functionalities associated with the selected utilities is shown below in Figure 4. Toronto Hydro falls within the range of the selected utilities in terms of electricity delivered annually, as shown in Figure 2. Although certain selected utilities serve a larger load or area, Toronto Hydro serves a uniquely important load. Toronto Hydro serves the provincial capital as well as the economic and financial center of Canada; in fact, it serves the highest proportion of national economic activity out of all the identified utilities. In addition, Toronto Hydro has amongst the highest customer densities of the identified utilities and distributes approximately 19% of electricity consumed in Ontario.[3]

[3] Toronto Hydro. *About Us.* <https://www.torontohydro.com/sites/corporate/AboutUs/Pages/AboutUs.aspx>

Figure 4. Summary of identified utility distribution operations

	Metric	Toronto Hydro	Hydro One	FPL	PG&E	CECONY	SDGE
	Province/State of utility service territory	Ontario	Ontario	Florida, US	California, US	New York, US	California, US
Load Significance	**Delivered electricity (GWh, 2016)**	25,373	26,289*	108,871	68,820	45,745	19,200
Load Significance	**Number of customers ('000)**	768	1,355	4,900	5,400	3,400	1,400
Load Significance	**Service area (km^2)**	630	962,774	71,613	181,299	1,564	10,619
Load Significance	**Service area density (customers/km^2)**	1,219	1	68	30	2,174	132
Load Significance	**Population of largest city served ('000)**	2,732	<80	454	1,025	8,538	1,406
Load Significance	**Serving provincial/state capital?**	✓	-	-	-	-	-
Load Significance	**Serving national financial center?**	✓	-	-	-	✓	-
Load Significance	**% of <u>national</u> economic activity in utility's service territory****	10.0%	<6%***	3.3%	6.2%	4.0%	1.2%
Control center operations	**Qualitative Justification**	Withstand extreme weather events, climate adaptation, terror threat	Reduce financial risk, customer impacts and reputational harm	Increase reliability, reduce time required to recover from storms	Strengthen grid resiliency and reliability, particularly for natural disasters; DER integration	Withstand and rapidly recover from an EMP attack	Maintain reliability, DER related reliability concerns
Control center operations	**Mode of operation**	One backup, Proposed: dual control centre	One backup, Proposed: dual primary control centre	Two backups	Parallel Three centers co-run	Parallel Four centers co-run + mobile backup	One backup
Control center operations	**Manned/Unmanned**	Unmanned, Proposed: Manned	Manned	Unmanned	Manned	Manned	Unmanned
Control center operations	**Functionality**	[redacted] proposed: [redacted]	Equivalent	Equivalent	Equivalent	Equivalent	Equivalent
Control center operations	**Cost (Canadian $ million)******	$40 (estimated cost of the proposed dual CC)	$65 (for proposed ISOC)	$55 (for one DCC)	$45 (average cost across three control centres)	n.a.	n.a.

* A total of 36,525 GWh were delivered through Hydro One distribution lines in 2016 - this includes electricity distributed to consumers who purchased power directly from the IESO

** Economic activity in Toronto Hydro service territory measured by comparing the 2016 annual GDP for the city of Toronto to Canada as a whole, using GDP estimates available from the city of Toronto's website. Economic activities in US utility's service territory was measured using county-level Personal Income data published by the US Bureau of Economic Analysis. Economic activity in counties the US utilities serve were then summed up and compared to total national Personal Income

*** Economic activity in Hydro One's distribution service territory is very difficult to estimate. Data available on Statistics Canada's website [CANSIM Table 381-5000] from 2009 provides GDP estimates for 15 metropolitan areas in Ontario, as well an estimate for 'non-census metropolitan areas' in Ontario. Assuming all economic activity in Ontario's 'non-census metropolitan areas' falls under Hydro One service territory, then this value divided by the total Canadian GDP estimate from the same data source indicates that 5.7% of Canada's economic activity falls within Hydro One's distribution service territory

**** Costs of US control rooms converted to Canadian dollars using an exchange rate of 1.3 CAD:1 USD (as of June 1st, 2018)

Sources: FERC, EIA, BEA, US Census Bureau, Statistics Canada, City of Toronto, Company reports and websites

3.1 Hydro One

Hydro One's primary power control center was opened in 2005 and cost $118 million.[4] The control center monitors both Hydro One's distribution and transmission networks in Ontario. Named the "Ontario Grid Control Centre", it consolidated monitoring and control functions under one roof, instead of the previously isolated regional control centers.

Hydro One also maintains a BUCC in Toronto originally commissioned in 1956 and is seeking to upgrade its control center capabilities (including both distribution and transmission) under its ongoing custom Incentive Rate-setting application for 2018-2022 electricity distribution rates [EB-2017-0049]. Hydro One has stated that its current BUCC requires upgrading due to an increased risk of facility failure. Hydro One has cited the main reasons to upgrade the facility as:

(i) regulatory compliance;
(ii) financial risk;
(iii) customer impacts; and
(iv) reputational harm.[5]

Hydro One presented a number of alternative approaches to replace/upgrade the existing BUCC operations, which are summarized in Figure 5 below (along with the costs associated with the distribution portion of these alternatives).

Figure 5. Alternative BUCC replacements initially presented by Hydro One

Alternative	Description	Distribution portion of costs ($ million)
1	Maintain status quo and use offsite leased space	$39
2	Build Network Operating Division ("NOD") BUCC and Data Centre ("DC") exclusively	$52
3	Build Integrated System Operations Center ("ISOC") as BUCC and Backup IT Management Center ("BUITMC"), with back office support areas and an integrated DC	$62
4	Acquire an existing facility for BUCC and BUITMC and integrated DC	N/A
5	Build Primary NOD Control Centre, primary SOC, and BUITMC	$71
6	Build ISOC capable of "dual primary" operations ***[Recommended by Hydro One]***	$65

Note: The above values represent only the distribution portion of costs. Total cost estimates for these listed alternatives are approximately double the values shown above.
Source: Hydro One exhibit B1-2 (OEB case EB-2017-0049) from April 4, 2017, pdf page 1314-1315

Of the approaches presented, Hydro One recommended the construction of a new Integrated System Operations Center ("ISOC"). Importantly, the ISOC would eventually allow Hydro One

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[4] Hydro One. *Exhibit B1-2 from OEB case EB-2017-0049.* April 4, 2017 <http://www.rds.oeb.ca/HPECMWebDrawer/Record/569822/File/document>

[5] According to Hydro One's rate application for the 2015-2019 period

to operate a "dual primary" scenario, where both the current and new control centers can operate in parallel. Hydro One's distribution rate application is currently still ongoing.

3.2 Consolidated Edison

Consolidated Edison Company of New York ("CECONY") is a regulated utility which provides electric service to 3.4 million customers in New York City and Westchester County.[6] In addition to servicing a 604 square mile electric service territory, it also distributes natural gas and district energy steam. CECONY is divided into four different operating regions (Bronx/Westchester, Brooklyn/Queens, Manhattan, and Staten Island), each with an Electric Distribution Control Center which is responsible for coordinating switching operations and feeder processing for restoration of outages.[7] These DCCs are staffed 24/7. CECONY has highly concentrated underground distribution networks, which typically witness fewer interruptions in the face of weather events, in comparison to overhead systems common elsewhere.[8]

In recent years, CECONY has undertaken significant expense to upgrade its DCCs. A review of its reported annual capital expenditures from 2011-2016 shows total actual costs for "Electric Distribution Control Center Upgrades" of $23.7 million USD. [9,10,11,12,13,14] This work includes a project to upgrade the IT server, network, UPS infrastructure, and enhance the electrical and HVAC design of all DCCs. CECONY's justification for the project was that the DCCs are "vital to maintaining [their] ability to deliver safe and efficient services".[15] CECONY's

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[6] ConEdison. *Company History and Statistical Information.* <https://www.coned.com/en/about-us/corporate-facts>

[7] NYDPS. *ELECTRIC INFRASTRUCTURE AND OPERATIONS PANEL*. Jan 29, 2015. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B4BEE2FD7-6E49-40AE-B007-3B76085F31AC%7D>

[8] NYDPS. Office of Electric, Gas, and Water. *2016 Electric Reliability Performance Report*. June 2017. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BBBCBF3C3-1812-4EEC-9E31-6901AED885D3%7D>

[9] ConEdison. *Report on 2011 Capital Expenditures*. February 28, 2012.

[10] ConEdison. *Report on 2012 Capital Expenditures*. February 28, 2013.

[11] ConEdison. *Report on 2013 Capital Expenditures*. February 28, 2014.

[12] ConEdison. *Report on 2014 Capital Expenditures and 2015-2019 Electric Capital Forecast*. March 2, 2015.

[13] ConEdison. *Report on 2015 Capital Expenditures and 2016-2020 Electric Capital Forecast*. February 29, 2016.

[14] ConEdison. *Report on 2016 Capital Expenditures and 2017-2021 Electric Capital Forecast*. February 28, 2017.

[15] NYDPS. *Electric Infrastructure and Operations Panel*. Jan 29, 2015. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B4BEE2FD7-6E49-40AE-B007-3B76085F31AC%7D>

decision to invest in the project was to provide "a high level of availability to allow the operators, designers and engineers to make proper decisions during major distribution system events".[16] CECONY continues to invest in updating its distribution management; a multi-year outage management system integration project was initiated in 2018.[17]

In addition to multiple DCCs, CECONY is building the world's first utility Hardened Mobile Control Center ("HMCC") to enhance its ability to withstand and rapidly recover from an Electromagnetic Pulse ("EMP") attack. An EMP would potentially destroy many key control center systems and devices, leaving the utility operating with limited visibility, vulnerable to multiple contingencies, and possibly requiring reduced load and extended outages.[18] The HMCC is a modular backup system consisting of completely self-sufficient and self-contained elements that have their own power supplies. It would take over system operations in less than one day after an EMP attack, down from weeks or months. The system will be on a mobile platform consisting of three tractor trailers enclosures that can be deployed to one or several locations, that can support workstations for 16 operators in total. The contract to build the HMCC was awarded in December 2017.

As justification for the HMCC, CECONY cited growing tensions in world events and findings from a commission established by US Congress to assess threats of an EMP attack.[19] This commission concluded several potential adversaries would have the capability to attack the US with an EMP, even without a high level of sophistication, and that an "EMP is one of a small number of threats that can hold our society at risk of catastrophic consequences". CECONY describes the HMCC as a proactive and sensible approach to prepare for this threat.

3.3 Pacific Gas and Electric

Pacific Gas and Electric ("PG&E"), which serves around 5.4 million customers in California and has 140,000 miles of lines, operates three electric distribution control centers (Fresno, Rocklin, and Concord) over an entire service area exceeding 180,000 km^2. PG&E consolidated its 15 existing electric operations centers into these three centers in 2016, as part of its effort to create a "smart, more resilient grid". Each of the three centers monitor and control approximately one-third of PG&E's service region, also known as a parallel mode of operation. The centers provide the ability

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[16] ConEdison. Exhibit IIP-13. <https://legacyold.coned.com/documents/2013-rate-filings/Electric/Exhibits/076-IIP-13-ITCategory.pdf>

[17] GridBright. *ConEd Selects GridBright for Distribution Management Integration*. August 2017. <https://gridbright.com/coned-integration>

[18] Consolidated Edison. *Case 16-E-0060 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*. Feb 28, 2018 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B105D820F-4CE5-4E84-9E28-CC4F813E6158%7D>

[19] Ibid.

"to shift operations to the two other regional control centers if support is needed at one in the event of a major storm or natural disaster."[20] The centers were constructed with redundant data feeds and emergency back-up capabilities to be able enhance resiliency in the face of unforeseen events such as major storms or natural disasters.

PG&E's three DCCs cost a total of approximately $105 million USD. The first control center in Fresno opened in late 2014, at a total cost of $28.5 million USD. The second control center in Concord cost $40 million USD and was opened in August 2015. The third control center in Rocklin opened in February 2016, at a total cost of $36 million USD.[21]

According to PG&E, investment in these control centers will "strengthen resiliency of the grid, while enhancing electric reliability",[22] as well as advancing the integration of DERs into its distribution system. Smart grid technologies were also piloted and deployed alongside the control center consolidation.[23]

3.4 Florida Power & Light Company

FPL is one of the largest US electric utilities, serving approximately 4.9 million customers in Florida.[24] FPL operates three DCCs and maintains two backups near two of its control centers, and has "implemented multiple levels of resiliency and redundancy in both its transmission and distribution substations and control centers".[25] Not only is each facility equipped with redundant energy management systems, but each backup facility is geographically diverse, fully functional, and has dedicated and redundant communication links. This allows a BUCC to quickly and effectively take over if the primary control center loses functionality. The BUCCs closely replicate the main control centers and can also be accessed remotely from the nearby DCC. The BUCCs are

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20 PG&E. *PG&E Opens New $40 Million State-Of-The-Art Electric Control Center in Concord.* August 20, 2015. <https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20150820_pge_opens_new_40_million_state-of-the-art_electric_control_center_in_concord>

21 PG&E. With Opening of New Rocklin Facility, PG&E Completes Move to Industry-Leading, High-Tech Electric Distribution Control Centers. February 03, 2016. <https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20160203_with_opening_of_new_rocklin_facility_pge_completes_move_to_industry-leading_high-tech_electric_distribution_control_centers>

22 Ibid.

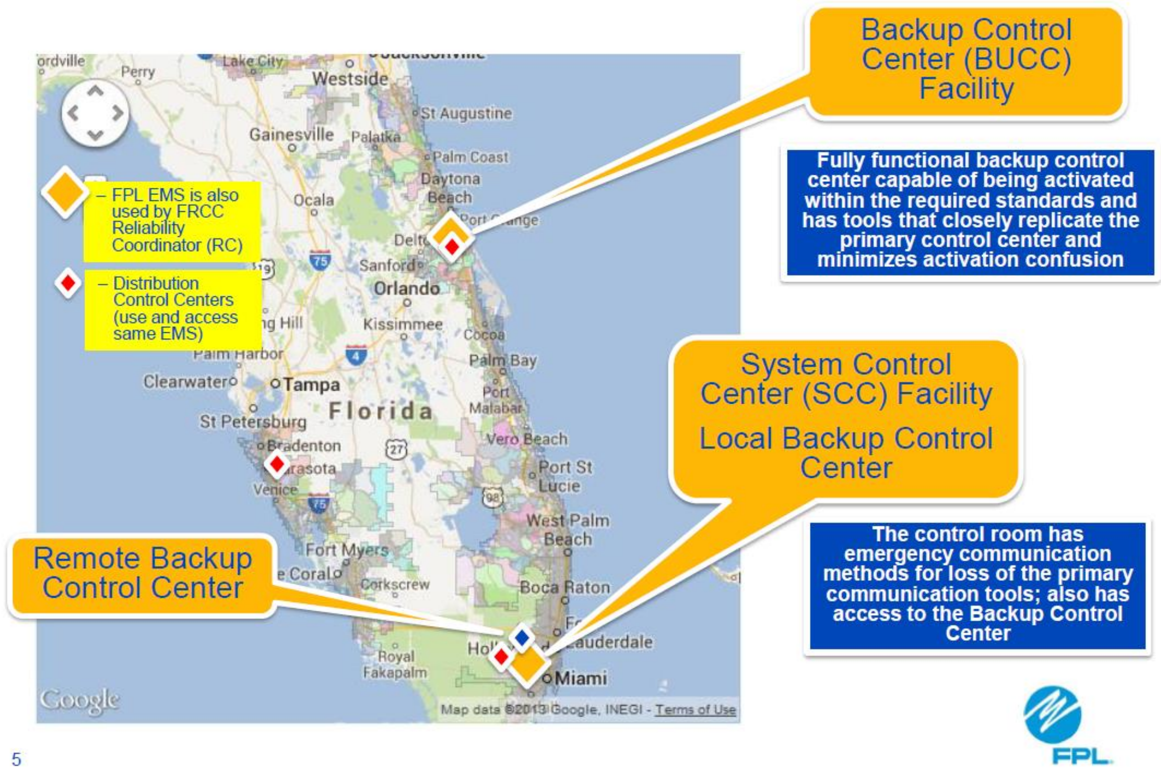
23 PG&E. *Smart Grid Annual Report – 2017.* September 29, 2017. https://www.pge.com/pge_global/common/pdfs/safety/how-the-system-works/electric-systems/smart-grid/Annual-Report-2017.pdf>

24 Florida Power & Light. *Company Profile*. <https://www.fpl.com/about/company-profile.html>

25 State of Florida Public Service Commission. *Review of Physical Security Protection of Utility Substations And Control Centers*. December 2014. P. 29 <http://www.psc.state.fl.us/Files/PDF/Publications/Reports/General/Electricgas/Physical_Security_2014.pdf>

unmanned, so they do not run in parallel,[26] and can be considered "cold" backups. These DCCs support FPL's business continuity and recovery plans, and increase reliability and reduce time required to recover from storms.

Figure 6. FPL DCC locations



Source: NERC. *NERC Monitoring and Situational Awareness Conference: Loss of Control Center Procedures and Testing Practices*. September 19, 2013

In January 2017, FPL began construction on a $42 million USD DCC in West Palm Beach. It is located next to FPL's command center, a hub opened in 2012 that coordinates overall storm response.[27] The new center will be built to withstand Category 5 hurricanes, and will consolidate the two existing distribution control centers located in Miami and Sarasota. These enhancements come as part of FPL's $2 billion USD plan to harden its infrastructure against natural disasters.

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[26] NERC. *NERC Monitoring and Situational Awareness Conference: Loss of Control Center Procedures and Testing Practices*. September 19, 2013 <https://www.nerc.com/pa/rrm/Resources/MonitoringSituationalAwarenessDL/9.%20FPL_Loss_of_CC_Testing%20-%20Ed%20Batalla.pdf>

[27] Palm Beach Post. "*FPL breaks ground on distribution center to be Cat-5 storm ready*". January 18, 2017. <https://www.palmbeachpost.com/business/fpl-breaks-ground-distribution-center-cat-storm-ready/n5kRoKXSks4jcUpGRbz9SN/>

3.5 San Diego Gas & Electric

San Diego Gas & Electric ("SDGE") is a regulated utility which provides electric service to 1.4 million customers in San Diego County and a portion of Orange County, California, over a total area of around 10,600 km^2. SDGE owns 21,000 miles of distribution lines serving 25 communities and operates transmission lines as well as two generating stations. The monitoring, operation and dispatch for the entire SDGE electric network occurs from the Mission Control facility. A project to modernize these operations in terms of data infrastructure and workstations was forecast to cost $16.3 million USD;[28] justifications included "reducing time to identify abnormal or adverse system conditions" allowing for better and faster decisions.

SDGE also has a fully-functional backup DCC located 10 miles away from its primary control center which is used to continue to maintain reliability under emergency scenarios such as loss of the primary facility or any failure of computer or communications systems.[29] The "cold" backup center has redundant connectivity allowing for operators to virtually connect to the BUCC in the case of a failure of the primary energy management system, while physically remaining in the primary control center. The BUCC is also able to handle the situation where a total failure of connectivity means operators must relocate physically to the BUCC.

Note that SDGE is one of the leading utilities in incorporating DERs – in 2016 they were the first California utility to reach their net metering cap of 617 MW (though they continue to install solar capacity through the NEM 2.0 program).[30] In their control centers, SDGE has recognized that the high penetration of DER has contributed to greater risk of safety and reliability incidents.[31] Specific challenges identified include: reverse power flow, increased voltage variability, reduced switching flexibility, and a lack of visibility of actual circuit loads, among others.[32] For their operators, these challenges have added complexity to decision making and switching requirements.

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[28] SDGE. *Direct Testimony of R. Dale Tattersall (Real Estate, Land Services and Facilities)*. October 6, 2017.

[29] SDGE. *Prepared Direct Testimony of Don Akau on Behalf of San Diego Gas & Electric Company*. Sept 25, 2015. <https://www.sdge.com/sites/default/files/FINAL%2520Akau%2520Testimony.pdf >

[30] Utility Dive. *As SDG&E edges closer to net metering cap, solar installations not expected to slow*. June 22, 2016 <https://www.utilitydive.com/news/as-sdge-edges-closer-to-net-metering-cap-solar-installations-not-expected/421312/>

[31] SDGE. *Revised San Diego Gas & Electric Company Direct Testimony of William H. Speer (Electric Distribution O&M)*. December 2017. <https://www.sdge.com/sites/default/files/SDG%2526E-15-R%2520Speer%2520Revised%2520Prepared%2520Direct%2520Testimony.pdf>

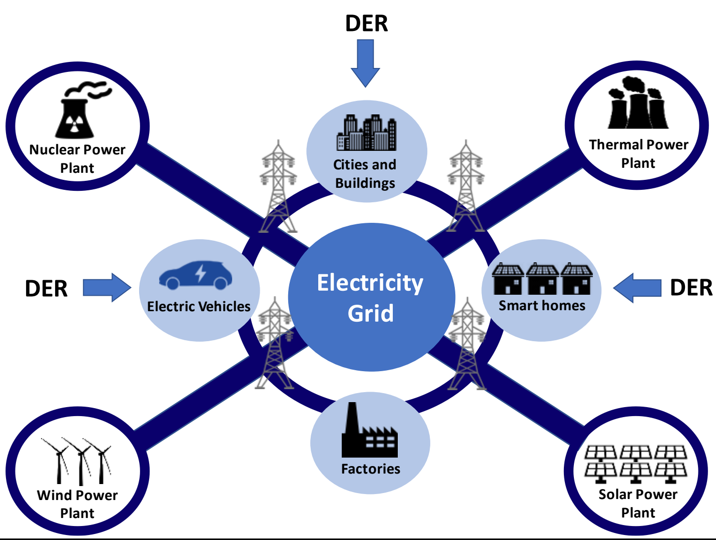
[32] Utility Dive. *How SDG&E is dealing with high penetrations of rooftop solar*. July 25, 2014 <https://www.utilitydive.com/news/how-sdge-is-dealing-with-high-penetrations-of-rooftop-solar/290227/>

4 Impact of distributed energy resources on the role of distribution utilities

The following section discusses how the growth of DER has led distribution utilities to manage more complex operations. Ontario has seen significant DER growth, which has impacted distributor operations across the province in terms of monitoring and control of energy delivery as well as energy management. The growth of distributed generation has also given distributors some of the reliability responsibilities traditionally reserved for transmission utilities. Transmission utilities are part of the bulk electricity system and thus governed by NERC safety requirements, including the requirement for backup functionality of its control center. LEI believes as distribution utilities evolve towards more complex operations and greater responsibility for reliability, fully functional BUCCs will become increasingly necessary.

4.1 Changing role of the distribution utility

Figure 7. Distributed Energy Resource interaction with the electricity grid



Electricity distribution grids are undergoing fundamental changes with the advancement of industry trends such as DERs, smart grids, and integration of electric vehicles. These trends are challenging the traditional role of the distributor and the DCCs. The traditional power grid delivered power from large scale, centralized generation, through the transmission system and the distribution system to consumers. Therefore, DCCs only handled flows of electricity in a single direction: to electricity consumers. However, small scale generation and other DERs can now be found in the distribution side of the grid, as illustrated in Figure 7. Their growth means that distributors at times need to manage bi-directional flow of electricity between the utility and consumers. This fundamental change in utility operations adds a layer of complexity to control center operations, as they try to integrate, interpret, and act on this new information.[33] This evolution has caused DCCs to take on more operations which are more typically associated with TCCs, such as forecasting intermittent generation, energy scheduling, or dispatching generation to manage outages.

4.2 Growth of Distributed Energy Resources in Ontario

The definition for DERs can vary across jurisdictions, but generally they are decentralized, often modular, distribution grid-connected power supplying devices with smaller installed capacity. They often include power generation, storage, and demand response. In certain jurisdictions they may also have specific renewable, interconnection voltage or capacity requirements. The IESO definition of DERs is introduced in the textbox below.

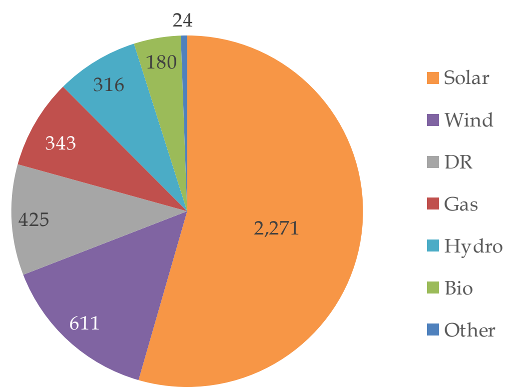
IESO definition of DERs

Distributed Energy Resources (DERs) are any electricity producing resources or controllable (dispatchable) loads connected to a distribution system that can serve electricity demand.

- DERs include, but are not limited to, generation, storage, and controllable load resources, but exclude persistent load reduction
- DERs may operate individually or be aggregated into virtual units
- DERs may connect directly to the distribution system or be integrated into a load

Source: IESO. *Grid-LDC Coordination and Interoperability Initiatives*. September 26, 2017. <http://www.ieso.ca/-/media/files/ieso/document-library/tp/2017/iesotp-20170926-6-grid-ldc-distributed-energy-resources-presentation.pdf?la=en&hash=50850B963ECB5B17141A7BB7F740444DE777F3EF>

Figure 8. Contracted and Installed DER in Ontario as of February 2017 (MW)



Source: IESO. Grid-LDC Coordination and Interoperability Initiatives. September 26, 2017.

[33] Stevens-Adams, Susan Marie, Cole, Kerstan Suzanne, Haass, Michael Joseph, Jeffers, Robert Fredric, Warrender, Christina E., Burnham, Laurie, and Forsythe, James C. *Situation awareness and automation in the electric grid control room*. United States: N. p., 2015. Web.

In Ontario, the growth of DER has been significant – as of 2017, there is 4,169 MW of contracted and installed DER capacity,[34] which is broken down in Figure 8. This includes over 2,000 MW of solar and 600 MW of wind connected to the distribution system. Solar and wind DER capacity is expected to grow to a total of over 3,000 MW by the early 2020s, and 34 MW of storage is also expected.[35] Between 2009 and 2016, Toronto Hydro has enabled approximately 81.9 MW of renewable generation, or over 1,572 interconnections.[36] Toronto's 2009 Sustainable Energy Strategy calls for an increase of 550 MW of renewable generation,[37] which is estimated to result in an additional 9,000 interconnections.[38] In the 2017 Long Term Energy Plan ("LTEP"), the Government of Ontario also refers to the future growth of DERs, including energy storage, microgrids, electric vehicles, in addition to renewable generation.[39] Although the 2017 LTEP does not explicitly state procurement targets, it has led to the development of the IESO's Renewable Distributed Generation Integration ("RDGI") Fund which will fund DER and smart-grid integration demonstration projects.[40]

The IESO has recognized impacts of DER to distributors and the broader bulk electric system. In 2017 it convened the Grid-LDC Inter-Operability Standing Committee, with the objectives of discussing issues and opportunities to coordinate management of the system.[41] Parties have discussed DER integration challenges, issues in forecasting, and data availability and sharing, with the goal of initiating pilot projects enabling greater coordination between LDCs and the IESO.[42]

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[34] IESO. *Grid-LDC Coordination and Interoperability Initiatives*. September 26, 2017. <http://www.ieso.ca/-/media/files/ieso/document-library/tp/2017/iesotp-20170926-6-grid-ldc-distributed-energy-resources-presentation.pdf?la=en&hash=50850B963ECB5B17141A7BB7F740444DE777F3EF>

[35] Ibid.

[36] Toronto Hydro. *2016 Toronto Hydro Environmental Performance Report*. 3/3/2017. <https://www.torontohydro.com/sites/electricsystem/corporateresponsibility/Documents/2016%20Toronto%20Hydro%20Environmental%20Report%20-%202017-03-09.pdf>

[37] City of Toronto. *The Power to Live Green: Toronto's Sustainable Energy Strategy*. October 19, 2009 <https://www.toronto.ca/legdocs/mmis/2009/ex/bgrd/backgroundfile-24583.pdf>

[38] Assuming 2009-2016 average rate of 52 kW per interconnection.

[39] Government of Ontario. *2017 Long-Term Energy Plan: Delivering fairness and choice*. <https://www.ontario.ca/document/2017-long-term-energy-plan>

[40] IESO. *Renewable Distributed Generation Integration (RDGI) Fund*. March 29, 2018. http://www.ieso.ca/-/media/files/ieso/document-library/engage/rdgif/rdgif-20180329-presentation.pdf?la=en

[41] IESO. *Grid-LDC Inter-Operability Standing Committee Terms of Reference*. March 2017. <http://www.ieso.ca/-/media/files/ieso/document-library/standing-committee/gli/gldc-20170327-terms-of-reference.pdf?la=en>

[42] IESO. *Where Do We Go From Here*. Feb 8, 2018. <http://www.ieso.ca/-/media/files/ieso/document-library/standing-committee/gli/gldc-20180208-planning-discussion.pdf?la=en>

4.3 Role of the Distribution System in Reliability

Potential DER impact to bulk system reliability

The bulk electricity system (including the transmission system) in the Continental US and Canada is under the regulatory authority of NERC, which develops and enforces reliability standards. NERC has studied the potential impacts to the bulk system from high levels of DER. NERC noted the operations at wholesale and retail, and transmission and distribution "may be increasingly blurred" and that additional communication and controls infrastructure will be required to handle the operational challenges associated with coordinating distribution and bulk data. Bulk system reliability impacts identified include:

- Non-dispatchable ramping/variability of certain DER
- Response to faults: lack of low voltage ride through, lack of frequency ride-through and coordination with the IEEE 1547 interconnection standards for distributed generation
- Potential system protection considerations
- Under Frequency Load Shedding (UFLS) and Under Voltage Load Shedding (UVLS) disconnecting generation and further reducing frequency and voltage support
- Visibility/controllability of DER
- Coordination of system restoration
- Scheduling/forecasting impacts on base load/cycling generation mix
- Reactive power and voltage control
- Impacts on forecast of apparent load seen by the transmission system

Source: NERC. *Potential Bulk System Reliability Impacts of Distributed Resources*. August 2011. https://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf

The growth of DERs has not only shifted the role and responsibilities of distributors and their DCCs, but the distribution system has also taken on greater importance from a bulk system reliability perspective. Traditionally, DCCs and TCCs have been managed separately and there has been minimal coordination between them. This is because the impact of the distribution system on the transmission system was previously assumed to be trivial.[43] This is generally true at lower DER penetration rates, as any impacts can be managed by bulk power system

[43] Li, Zhengshuo. *Distributed Transmission-Distribution Coordinated Energy Management Based on Generalized Master-Slave Splitting Theory*. January 24, 2018. P. 1.

resources.[44] However, a distribution system with significant DER integration can cause issues in transmission line loading, grid voltage, and system frequency,[45] and may change its operating state more often which can impact bulk system reliability.[46]

Utilities, Independent System Operators ("ISOs"), and their respective regulatory authorities also recognize issues caused by DERs. Utilities located within the Electric Reliability Council of Texas ("ERCOT") had interconnected nearly 900 MW of DERs in their service territories (at or below 60 kV) as of 2015. Although these resources do not pose an immediate concern at the transmission level, ERCOT noted several potential reliability issues for the bulk system with higher DER penetration. These include increased error in load forecasting resulting in excessive reliance on regulation and other ancillary services, and uncoordinated system restoration after a load shed event potentially causing large voltage or frequency swings. [47]

In Hawaii, over 10% of Hawaiian Electric's ("HECO") Oahu customers utilize rooftop solar. This high rate of DER penetration has resulted in distribution circuits exceeding 100% of daytime minimum load.[48] HECO implemented restrictions on PV interconnections, citing that additional PV may cause distribution circuits to become dangerous and unreliable due to overvoltage, voltage variations, and islanding issues. Impacts to the transmission system include magnifying transients, accelerating transients, degrading control measures and frequency instability.[49]

The distribution system was found to be one of the contributing factors in the Arizona-Southern California 2011 outages, where an 11-minute system disturbance in the Pacific Southwest caused cascading outages impacting an estimated 2.7 million customers.[50] A Federal Energy Regulatory Commission ("FERC")/ North American Electric Reliability Corporation ("NERC") study on this outage found that "the separate management over [transmission power subsystems] and

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[44] NERC. *Distributed Energy Resources Connection Modeling and Reliability Considerations*. February 2017. <http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

[45] Ibid.

[46] Li, Zhengshuo. *Distributed Transmission-Distribution Coordinated Energy Management Based on Generalized Master-Slave Splitting Theory*. January 24, 2018. P. 1.

[47] ERCOT. Distributed Energy Resources (DERs) Reliability Impacts and Recommended Changes. March 2017. <http://www.ercot.com/content/wcm/lists/121384/DERs_Reliability_Impacts_FINAL.pdf>

[48] Greentech Media. *How Much Solar Can HECO and Oahu's Grid Really Handle?*. February 2014. <https://www.greentechmedia.com/articles/read/how-much-solar-can-heco-and-oahus-grid-really-handle#gs.1tYivlI>

[49] HECO. *Renewables in Hawaii*. February 6, 2014. < https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_of_Trustees_Presentations-February_6_2014.pdf>

[50] FERC. *Arizona-Southern California Outages on September 8, 2011*. April 2012. <https://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf>

[distribution power subsystems] is insufficient to ensure the operational security of an integrated T-D power system".[51] The NERC Distributed Energy Resources Task Force has also highlighted the importance of data sharing and coordination between distribution and transmission utilities.[52]

These examples, as well as the IESO's Grid-LDC Inter-Operability Standing Committee that was introduced in Section 4.2, show that the operation of the distribution system is becoming more important to bulk system reliability. Bulk system utilities are required by NERC to have backup functionality for their control center. LEI believes that the case for a fully functional backup distribution control center is further supported by the evolving challenges of integrating DERs, and the importance of coordination between the distribution and transmission utility.

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51 Li, Zhengshuo. *Distributed Transmission-Distribution Coordinated Energy Management Based on Generalized Master-Slave Splitting Theory*. January 24, 2018. P. 1.

52 NERC. *Distributed Energy Resources Connection Modeling and Reliability Considerations*. Feb 2017. <https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf>

5 Economic case analysis for proposed control center

This section summarizes LEI's analysis of an economic case for the proposed dual control center, utilizing the concept of Value of Lost Load ("VoLL"). As demonstrated below, based on estimates of VoLL for Toronto, the proposed dual control center could pay for itself if it could reduce the duration of relatively short high impact outages; examples of the type and duration of such outages are presented in Figure 9. Given that the dual control center provides operational benefits beyond reducing outage durations, this suggests that the investment is economically justified.

Figure 9. Type & duration of outage event equivalent to $40.2 million dual control center cost

Extraordinary outage event	Duration of outage
System-wide outage at average 2016 peak load (3,961 MW)	**20 minutes**
System-wide outage at average 2016 load (2,913 MW)	**28 minutes**
Outage at Windsor Transformer Station (300 MW peak)	**4.5 hours**

Note: This figure summarizes analysis covered in Section 5.2.

Toronto Hydro's service area covers the city of Toronto. With a population of 2.9 million as of July 2017 and a GDP of $193 billion CAD in 2016, [53,54] Toronto is Canada's largest city; it is comparable to entire provinces in terms of population and economic activity. Toronto is also Canada's economic and financial center; the Toronto Stock Exchange ("TSX") is the 9th largest exchange in the world by market capitalization. The city's continued economic functionality is highly dependent on maintaining reliable and resilient grid operations and continuous electricity distribution by Toronto Hydro.

5.1 Value of Lost Load

LEI believes that analysis based on VoLL is an effective method to estimate the economic cost of outages in the city of Toronto. If the cost of outages can be estimated, we can determine whether a particular investment intended to avoid or reduce the duration of such outages is economically worthwhile. VoLL is a socio-economic monetary indicator of the economic consequences of a power outage; it is an indicator of the economic value of sustained electricity supply. As with any investment or consumption choice, if cost is less than value, the optimal investment has been chosen, and resources are available, the investment should be made, or the item consumed. In the case of a utility, if an investment is cost-effective and costs less to achieve than the Value of Lost Load, then the investment should be pursued.

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53 City of Toronto. <https://www.toronto.ca/city-government/data-research-maps/toronto-at-a-glance/>

54 Toronto city GDP was $168 billion in 2016 measured in 2007 Canadian dollars. This value was inflated to 2016 dollars using inflation rate for Toronto based on StatsCan data [CANSIM Table 326-0021].

What is VoLL?

VoLL—usually measured in dollars per MWh—represents an indication of society's willingness to pay for electricity service (or to avoid curtailment). It is important to recognize that VoLL will vary depending on the type of outage considered. Generally, there are three broad classes of outages that can occur on an electricity grid:

- large-scale, long-term outages in which power is interrupted across a wide area for days or possibly even weeks due to a catastrophic event that causes a system-wide blackout and requires system restart and in some cases, extensive infrastructure repairs;
- more localized outages in which electricity service is unavailable for hours at a time (e.g., as a result of distribution service event or a more localized weather event, such as a tornado or a flood); and
- targeted, short-duration outages of select customers over more discrete timeframes. Long duration, system-wide outages will likely have the highest VoLL as the indirect and induced costs of the outage increase over time (loss of wages, loss of perishable goods, etc.).

Sources: adapted from London Economics International. *Estimating the Value of Lost Load*. June 17th, 2013; Schroder and Kuckshinrichs. *Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review*. December 24th, 2015

Accurately estimating VoLL for a given region and a specific type of outage depends on multiple factors such as the type of customer affected, regional economic conditions and demographics, time and duration of outage, and other specific traits of an outage. It is important to note that VoLL is a region-specific average representing what society as a whole would be willing to pay to avoid an outage; VoLL for specific customers may be higher or lower, and VoLL in specific hours of the day will be higher or lower than the overall reported average. VoLL is not a line item on any individual customer's bill. Instead, it is used for planning purposes to determine at what point society is better off to forgo the use of electricity rather than to make an investment that contributes to additional reliability.

Four key methodologies are used in the estimation of VoLL: (i) macroeconomic analysis; (ii) a survey of stated choices; (iii) a survey of revealed preferences; and (iv) case studies. Macroeconomic analysis and surveying stated choices are more common due to the relative ease of data acquisition.[55]

[55] Surveying revealed preferences is based on actual investments made by customers that install or procure back up power, meaning that a significant portion of customers will not be surveyed. Case studies depend on data obtained from an actual outage, which is difficult to obtain for a significant portion of customers; moreover, the available case studies may not be representative of forthcoming outages, particularly in other jurisdictions.

The macroeconomic approach involves the application of an electricity intensity ratio, such as GDP/kWh, based on the assumption that a power cut would result in a proportionate drop in economic activity. On the other hand, customers' perceived values can be surveyed to ask about the cost that a customer is willing to incur to avoid a power outage—or the amount of money a customer would need to be compensated to accept a power outage. Whether it is willingness to pay or willingness to accept payment, both approaches are used to estimate the direct cost that a customer would incur as a result of an outage.

LEI previously performed for Electric Reliability Council of Texas ("ERCOT") an extensive review of VoLL calculations in different jurisdictions; the studied jurisdictions all used one of the techniques discussed above.[56] LEI's study found that average VoLL for a developed, industrial economy ranges from approximately US$9,000/MWh to US$45,000/MWh, shown in Figure 10 below.[57]

Figure 10. Summary of VoLL by jurisdiction

Region/Market	Methodology	VoLL (CAD)	VoLL (USD)
New Zealand	Survey	$42,503	$41,269
Australia - Victoria	Survey	$45,767	$44,438
Australia	Survey	$47,075	$45,708
Republic of Ireland	Macroeconomic analysis	$9,823 - $16,751	$9,538 - $16,265
US - Northeast	Macroeconomic analysis	$9,561 - $14,341	$9,283 - $13,925

Sources: "Investigation into VOLL in New Zealand", "Assessment of the Value of Customer Reliability (VCR)", "Valuing Reliability in the National Electricity Market", "An Estimate of the Value of Lost Load for Ireland", "The Economic Cost of the Blackout"
Note: USD to CAD conversion rate is 1:1.0299, based on the 2013 average annual exchange rate

IESO utilized the concept of VoLL in its 2015 Central Toronto Integrated Regional Resource Plan. As part of this 25-year plan, IESO conducted a Probabilistic Reliability Assessment to estimate the economic impact of the risk of outages,[58] using a VoLL assumption of CAD$30,000/MWh.[59,60]

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56 London Economics International. *Estimating the Value of Lost Load.* June 17, 2013. <http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf>

57 Ibid.

58 IESO. *Central Toronto Area Integrated Regional Resource Plan*. April 28, 2015. <http://www.ieso.ca/-/media/files/ieso/document-library/regional-planning/central-toronto/2015-central-toronto-irrp-report.pdf?la=en>

59 Independent Electricity System Operator. *Central Toronto Area Integrated Regional Resource Plan – Appendices.* April 28, 2015. <http://www.ieso.ca/-/media/files/ieso/document-library/regional-planning/central-toronto/2015-central-toronto-irrp-report-appendices.pdf?la=en>

60 This assumption is similar to a 2004 estimate of USD 22,600/MWh which used a survey-based methodology. (Bhavaraju, M., *Variable Resource Requirement*, PJM Stakeholder Meeting. 2004.)

As this assumption falls within LEI's previous study ranges for VoLL, LEI believes a $30,000/MWh is an appropriate VoLL assumption in Toronto Hydro's service territory.

5.2 Economic costs of an extraordinary event

Low-probability events such as terrorist attacks or extraordinary weather events can have significant system impacts – for example, flooding could cause outages and result in the inability to operate Toronto Hydro's primary control center. Note that extraordinary weather events are predicted to become more frequent due to climate change – for example, maximum daily rainfall in Toronto is expected to more than double by 2040, increasing the risk of flooding near critical components.[61] To the extent the primary control center cannot be used at the same time that significant system outages occur, Toronto Hydro's ability to restore service would be significantly delayed – the control center plays a vital role during recovery, including coordinating with field personnel, data analysis, switching, isolation, and facilitation of emergency reactive work.

The most beneficial case would be reducing the duration of a system wide outage. Toronto Hydro supplied a total of 25,588 GWh in 2016, which averages to about 2,913 MWh delivered per hour, and had an average peak load of 3,961 MW.[62] Taking Toronto Hydro's average load per hour of 2,913 MWh, and assuming a VoLL price of $30,000/MWh, the $40.2 million cost for the dual control center represents reducing the duration of a system-wide outage by 28 minutes at VoLL prices.[63] Assuming the outage occurs during an average peak load hour, the representative cost of the control center drops to reducing the duration a system-wide outage by 20 minutes. This shows that it would only take the reduction in duration of a single system-wide outage of these lengths over the lifetime of the control center investment to recover the construction costs.

To put these outage times in context, Toronto Hydro's System Average Interruption Duration Index ("SAIDI") has averaged 0.98 hours from 2012-2016, or 58.8 minutes; Figure 11 presents Toronto Hydro's historical SAIDI from 2012 to 2016.

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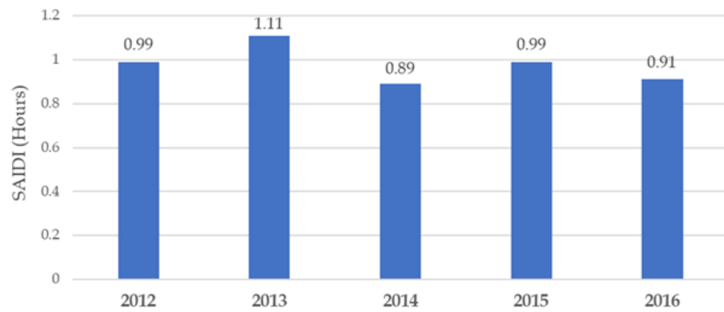
[61] City of Toronto. *TransformTO: Resilience and Adaptation to Extreme Weather.* < *https://www.toronto.ca/wp-content/uploads/2017/10/9801-TransformTO-Resilience-and-Adaption-to-Extreme-Weather-Workbook-Results-Summary-AODA-Compliant.pdf*>

[62] Data taken from the OEB's 2016 Yearbook on Electricity Distributors. Toronto Hydro's "average load per hour" estimated by dividing its 'Total kWh Supplied' from the OEB yearbook by the total number of hours in the year (8,784). Toronto Hydro's 'average peak load' taken from the OEB's yearbook (page 62, line 15). Source: Ontario Energy Board. *2016 Yearbook of Electricity Distributors*. August 17, 2017.

[63] Toronto Hydro delivered a total of 25,588 GWh in 2016, which is an average of about 49 MWh delivered per minute. At a VoLL of $30,000/MWh, each average minute of a Toronto Hydro outage would cost around $1.46 million CAD. Therefore, an outage of 28 minutes would cover the full value of the new control center ($40.2 million CAD).

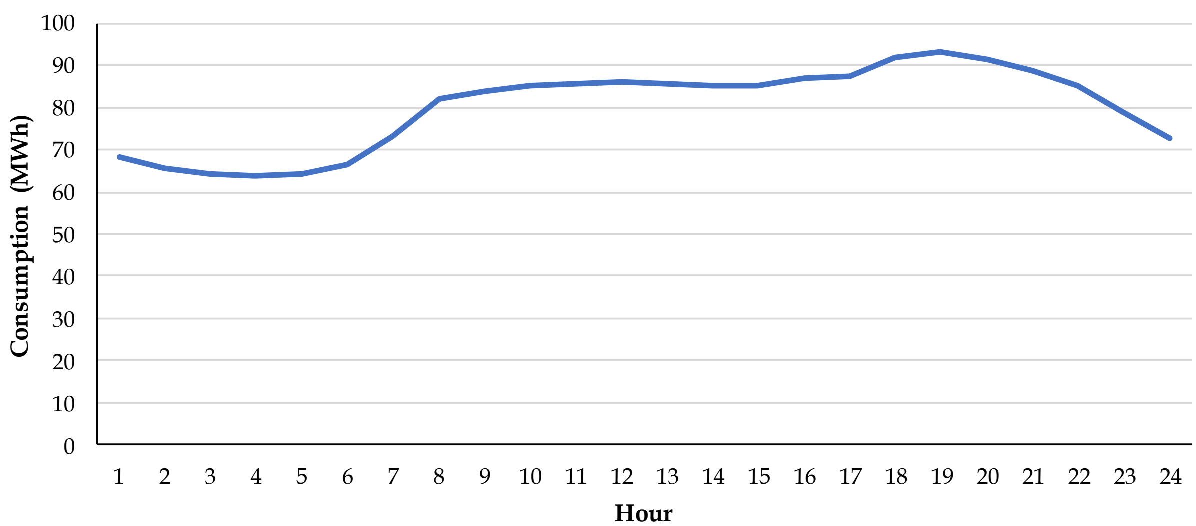
Figure 11. Toronto Hydro historical SAIDI (2012-2016)



Source: Toronto Hydro. *Scorecard - Toronto Hydro-Electric System Limited*. 9/24/2017.

More conservative cases involve the dual control center reducing the impact of losing a Transformer Station ("TS") at the same time as the primary control center, which could happen for example due to flooding which impacts both the control center and a TS. An example of the scale of TS losses occurred on January 15th, 2009, when the failure of the deluge system at the Dufferin TS caused an outage that lasted around 24 hours. Multiplying the $30,000/MWh VoLL assumption discussed previously, by an assumed customer demand profile over the 24-hour period as shown in Figure 12, the economic impact of such an outage is estimated to be $57.6 million, about 43% higher than the cost of the dual control center.

Figure 12. Assumed customer demand in Dufferin TS example

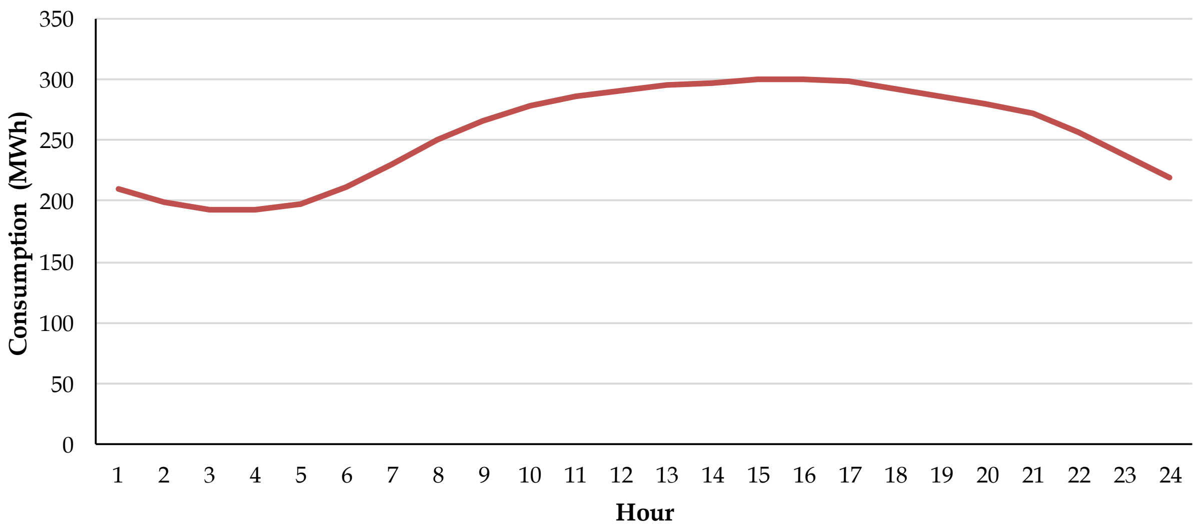


LEI estimated this demand shape in the outage location using the IESO's zonal demand for the Toronto Transmission Zone on January 15th, 2009. The outage to customers with an annual peak load of 113 MW was then fitted to the demand shape of the Toronto Transmission Zone on that day
Source: IESO 2009 zonal demand

Extended outages at larger Transformer Stations, such as the Windsor TS, are also possible and would have even greater effects including outages to Canada's economic and financial center. If a terrorist attack, fire, or flood causes the loss of the primary control center and the entire Windsor

TS, it could cause a loss of 300 MW at peak load. Assuming a VoLL of $30,000/MWh, a 300 MW peak load, and the demand profile shown in Figure 13 below, the $40.2 million cost for the control center represents in this example an outage duration of around 4.5 hours.[64]

Figure 13. Assumed customer demand in Windsor TS example



LEI estimated this demand shape in the outage location using the IESO's zonal demand for the Toronto Transmission Zone on its peak day for 2016, August 12th. The outage to customers with an annual peak load of 300 MW was then fitted to the demand shape of the Toronto Transmission Zone on that day

These examples show the potentially high economic impact of outages. LEI has estimated the loss of load possible during certain extraordinary events and using a VoLL of $30,000/MWh has estimated the economic cost of outages in the city of Toronto. The examples in this section show that relatively short duration outages would end up costing the equivalent of the $40.2 million cost of the dual control center. Therefore, if the dual control center could reduce the duration of potential outages or allow for a fully functional alternative in the event that the main control center needs to be evacuated, the avoided outage effects mean that the dual control center could essentially pay for itself.

[64] Duration reflects outage occurring at the highest demand hours (hours 13-17).

6 Concluding remarks

LEI believes there is a strong case to support a dual distribution control center for Toronto Hydro, based on the key points identified below:

- research in Section 3 shows a precedent for North American distribution utilities to build new fully functional backup distribution control centers to help alleviate reliability and resiliency concerns;
- observed construction costs for fully functional BUCCs are similar to those proposed by Toronto Hydro—see Figure 3;
- the importance of the load served by Toronto Hydro compares favourably to these examples;
- many of the justifications presented by other North American distribution utilities to add or enhance backup operations are equally applicable to Toronto Hydro—see Figure 4;
- an increase in adverse weather events, particularly maximum daily rainfall and flooding risks, further justify the need the need for a more capable alternative to the main control center in the case of a prolonged failure;
- the responsibilities of distribution utilities are evolving due to the proliferation of DERs, and with greater responsibility for reliability, alternate control centers will become increasingly necessary as discussed in Section 4; and
- from an economic perspective, the proposed cost of the dual control center can be justified given the significant costs associated with outages in the city of Toronto, and the potential for the dual control center to reduce the duration of high impact outages.

Appendix: List of Works Consulted

City of Orillia. *Hydro One Public Information Session*. September 29th, 2016.

City of Toronto. *TransformTO: Resilience and Adaptation to Extreme Weather.* September 2015.

FERC. *Arizona-Southern California Outages on September 8, 2011*. April 2012.

Hydro One Networks Inc. *Evidence, Exhibit B1-1-1. EB-2017-0049*. Received by the OEB on April 27th, 2014.

Hydro One Limited. *2017 Annual Report*. Released on February 13th, 2018.

IESO. *Central Toronto Area Integrated Regional Resource Plan – Appendices*. April 28th, 2015.

IESO. *Grid-LDC Coordination and Interoperability Initiatives*. September 26th, 2017.

IESO. *Grid-LDC Inter-Operability Standing Committee Terms of Reference*. March 2017.

IESO. *Where Do We Go From Here*. February 8th, 2018.

Li, Zhengshuo. *Distributed Transmission-Distribution Coordinated Energy Management Based on Generalized Master-Slave Splitting Theory*. January 24th, 2018. P. 1.

London Economics International. *Estimating the Value of Lost Load.* June 17th, 2013.

NERC. *Distributed Energy Resources Connection Modeling and Reliability Considerations*. February 2017.

NERC. *NERC Monitoring and Situational Awareness Conference: Loss of Control Center Procedures and Testing Practices*. September 19th, 2013.

New York Independent System Operator. *New Control Center Highlights 15th Year of Evolving Grid Operations and Markets.* January 2015.

New York Independent System Operator. *NYISO Control Center Project*. August 8th, 2011.

Ontario Energy Board. *2016 Yearbook of Electricity Distributors*. August 17th, 2017.

Ontario Energy Board. *Interrogatories. EB-2013*-0416. Exhibit I. Filed on July 4th, 2014.

Ontario Energy Board. OEB *Staff Report: Review of cost of capital for Ontario's regulated utilities*. January 14th, 2016.

Ontario Energy Board. *OEB cost of capital parameter updates for 2018 cost of service and custom Incentive-rate-setting application*. November 23rd, 2017.

PG&E. *Smart Grid Annual Report – 2017.* September 29th, 2017.

Schroder and Kuckshinrichs. *Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review*. December 24th, 2015.

State of Florida Public Service Commission. *Review of Physical Security Protection of Utility Substations And Control Centers*. December 2014. P. 29.

Stevens-Adams, Susan Marie, Cole, Kerstan Suzanne, Haass, Michael Joseph, Jeffers, Robert Fredric, Warrender, Christina E., Burnham, Laurie, and Forsythe, James C. *Situation awareness and automation in the electric grid control room*. United States: N. p., 2015.

Toronto Hydro. *Responses to Ontario Energy Board Staff Interrogatories on Issue 2.2*. [EB-2012-0064]. October 5th, 2012.

Vadari, Mani. *Electric System Operations: Evolving to the Modern Grid*. 2013.

Appendix B - List of Emergency Critical Functions

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

E8.2 Facilities Management and Security

E8.2.1. Summary

Table 1: Program Overview

2015-2019 Cost ($M): 35.3	**2020-2024 Cost ($M):** 60.4
Segments: Facilities Management and Security	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Public Policy, Environment, Safety, Financial	

Through the Facilities Management and Security Program (the "Program"), Toronto Hydro will invest in building improvements that are critical to the proper functioning of Toronto Hydro's electricity distribution system. The operation centres covered by the Program include four Toronto Hydro-owned work centres, that have unique footprints and functions, and 207 stations, the majority of which serve a critical role in the distribution of electricity.

The main objective of the Program is to maintain the infrastructure that supports critical operations of Toronto Hydro's distribution system, and to replace assets that are end of life and in poor condition. The Program addresses the following three areas:

1) **Work Centres:** includes repairs and improvements identified in detailed condition assessments of the four work centres located at 500 Commissioners Street, 14 Carlton Street, 71 Rexdale Boulevard and 715 Milner Avenue;
2) **Stations**: includes facilities-related repairs and improvements identified in detailed condition assessments for Toronto Hydro's distribution stations that are in poor condition and past useful life; and
3) **Security Improvements:** covers security enhancements necessary to protect Toronto Hydro's assets, employees and the public with up-to-date security equipment and technologies (i.e. installation of advanced Video Management System ("VMS"), upgraded card-access, and key management equipment). Toronto Hydro also plans to upgrade its Security Operations Centre ("SOC") to new security software standards to provide [redacted]

Figure 1: Examples of Toronto Hydro infrastructure that will be addressed through the Program

Maintenance investments that are part of the Program are prioritized to address critical assets that are at end of life and in poor condition. This is expected to lead to safe and reliable distribution of electricity as well as reduced lifecycle asset costs. Toronto Hydro selects candidates for repair and improvement based on detailed building asset condition assessments. The deficiencies identified as part of these assessments are classified into the following five categories:

- **Architectural***:* The volumes and functions of a building such as building foundation, roof, exterior enclosure and envelope;
- **Fire & Life Safety***:* Key components of the overall safety of the building. These ensure that the building is in compliance with the Ontario Building Code, Ontario Fire Code and other applicable regulations;
- **Mechanical & Electrical***:* The interior building systems and power distribution system required for the overall functionality of the building;

- **Civil**: Core building infrastructure including storm drainage, access ways, walk ways, windows; and
- **Plumbing**: The pipes, tanks, fittings and other apparatus required for the water supply, hot water heating, and sanitation in a building.

The Program also includes security improvement investments that will support Toronto Hydro's operations and improve physical security infrastructure. These security investments are also part of Toronto Hydro's efforts to continue alignment with the OEB's Cyber Security Framework.[1] This will be achieved by installing modern security equipment and technology, such as advanced access-control equipment and intercom devices at all of Toronto Hydro's buildings and stations. [redacted]

The Program is a continuation of the activities described in Toronto Hydro's 2015-2019 Rate Application.[2] However, in the 2015-2019 Rate Application, the funding requested for the Facilities Management and Security program covered building-related asset replacements for only 11 out of 207 stations. Since 2015, Toronto Hydro has created a robust facilities management system that records assessments and maintenance plans for all assets located in Toronto Hydro's work centres and stations. This repository system identifies the condition of all facilities-related assets (e.g. poor, fair, good) owned by Toronto Hydro, thereby ensuring that the utility efficiently performs the necessary maintenance work where required. As further described below, a number of Toronto Hydro's facilities assets are at end of life and in poor condition and will require extensive maintenance or replacement.

[1] Ontario Cyber Security Framework (December 6, 2017), available at: < https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf>.
[2] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 2B, Schedule 8.2.

E8.2.2. Program Outcomes

Table 2. Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Investing in stations and work centres' building-related improvements that are critical to the proper functioning of Toronto Hydro's electricity distribution; and ○ Mitigating the risk of damage to critical infrastructure housed within the stations (e.g. a sump pump failure could cause flooding and damage electrical equipment).
Public Policy	• Contributes to Toronto Hydro's public policy objectives by ensuring compliance with applicable regulatory and legislative requirements such as the OEB's Cyber Security Framework by: ○ leading the implementation, maintenance and continuous lifecycle management of modern commercial security systems and technology in partnership with security subject matter experts; ○ applying security management policies and procedures across all Toronto Hydro sites; and ○ Investing in physical security measures that helps safeguard private information. This is accomplished through measures that prevent unauthorized physical access to work centres.
Environment	• Contributes to Toronto Hydro's environmental objectives by: ○ Assisting with the achievement of goals outlined in Ontario's Climate Change Action Plan by reducing greenhouse gas emissions. This will be achievable through the use of new HVAC units that will consume less electricity and natural gas; and ○ Ensuring compliance with Ontario's Conservation First Framework by working towards decreasing Toronto Hydro's average electricity consumption across its buildings and work stations. This will be achieved through the use of new lighting that will consume less electricity.
Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by:

	○ Ensuring compliance with the Ontario Building Code and the Fire Code; ○ Repairing deficiencies which cause trip and fall hazards; ○ Addressing stations-related deficiencies such as absence of secondary exits, non-compliant stairs, and inaccessible doors along pathways; ○ Improving internal lighting conditions and repair external damaged lighting in work areas; and ○ Reducing the risk of unauthorized access into Toronto Hydro work centres and stations.
Financial	• Contributes to Toronto Hydro's financial objectives as measured by the total cost and efficiency measures by: ○ Utilizing detailed asset condition assessments in order to only replace those assets that are end of life and in poor condition; ○ Undertaking security enhancements at only certain work centres and stations, according to highest level of need and risk; ○ Prioritizing preventative maintenance of end of life assets that are in poor condition to mitigate against costly reactive repairs; ○ Deterring theft and vandalism through the installation of enhanced security systems; ○ Reducing utility costs at Toronto Hydro's work centres via the use of energy efficient HVAC and lighting systems; and ○ Eliminating unnecessary costs associated with the need to maintain obsolete fire systems by installing fire alarm systems that can be readily maintained using commercially available parts.

E8.2.3. Program Drivers and Need

Table 3. Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Safety and Failure Risk

The sections below provide a summary of the deficiencies inherent within work centres and stations, and the proposed work program for remediating those deficiencies.

E8.2.3.1 Aging and Deteriorating Assets

In 2016, Toronto Hydro conducted a thorough review of all assets and building systems located within all of its work centres and distribution stations. The objective of this review was to identify the infrastructure that was at greatest risk of requiring substantial repairs or replacement within the next ten years. The reviews are updated annually, based on field observations and capital work completed in the fiscal year. The assessments indicated that a number of critical building assets within Toronto Hydro's work centres and stations (e.g. foundation walls, sump pumps, roofs, fire alarm systems etc.) are in poor condition, obsolete or require substantial investments to maintain. Failure of these critical assets could have an adverse impact on the reliability of Toronto Hydro's system, as well as the safety of employees and the public. It also affects the ability to effectively respond to power interruptions or emergency situations.

Toronto Hydro used the methodology formulated in the Facilities Asset Management Strategy (the "Strategy", filed at Exhibit 2A, Section D5) to form the basis for its annual assessments. The Strategy was developed by Toronto Hydro on the basis of industry standards and knowledge sharing with subject matter experts, consultants, and service providers. Based on the Strategy, assets that receive a poor condition rating were to be addressed within one to five years. Assets that received a fair condition rating were to be closely monitored and/or maintained under a preventative maintenance program.[3] Finally, assets with a good condition rating did not require any repairs within the next one to ten years. Figure 2, below, illustrates the number of work centres and stations in need of some form of repair or remediation, both historical and forecast. A trend illustrating increasing stations-

[3] Preventive maintenance is performed under Facilities Management. For more information, refer to Exhibit 4A, Tab 2, Schedule 12.

related work to address building infrastructure (for instance, a damaged roof) that houses critical distribution equipment can be observed.

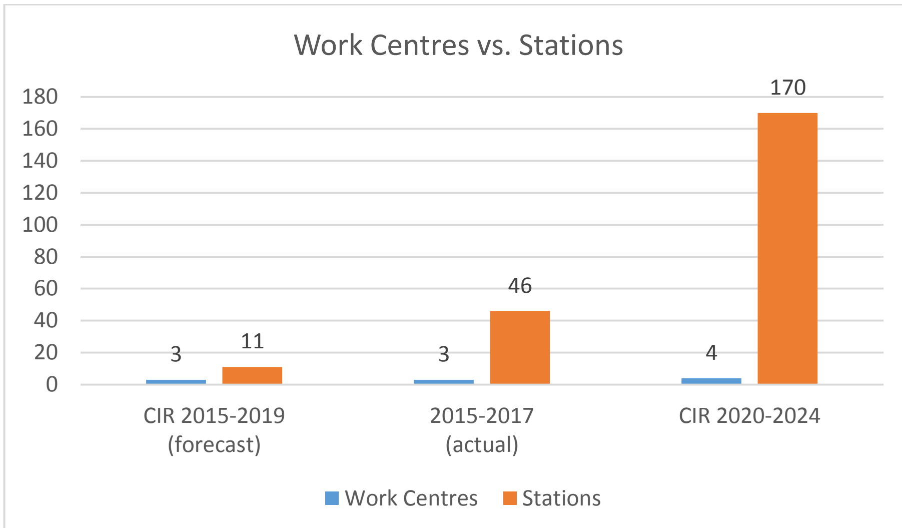


Figure 2: Forecast and Actual Program Work Volumes

Projects that are expected to be undertaken as part of the Program during the 2020-2024 plan period, along with their costs and high-level rationale are provided in Table 4, below.

Table 4: List of Program Projects Expected to be completed over the 2020-2024 Plan Period

Project Category	Cost ($M)	Rationale
Architectural repairs and remediation at work centres and stations (e.g. Trades Training Area upgrades, structural repairs, repair, or replacement of stations building envelope, etc.)	24.4	Addresses safety issues and prevents structural damage.
Fire and Life Safety (e.g. stations fire alarm system upgrades, signage and emergency lighting, etc.)	10.5	Replaces obsolete fire alarm systems and addresses safety and compliance issues.
Mechanical and Electrical (e.g. HVAC system replacement, supplementing cooling system, upgrading and replacement of lighting, sump pump replacement, etc.)	5.1	Addresses assets in poor condition, equipment overloading and capacity issues, safety concerns, and compliance with mandated requirements.

Project Category	Cost ($M)	Rationale
Civil (e.g. exterior access ways and walkways, including pavement, driveways, and parking spaces, etc.)	4.5	Addresses safety-related concerns.
Plumbing (e.g. plumbing fixtures, hot water tanks, etc.)	1.3	Addresses assets in poor condition.
Security Improvements (e.g. access control upgrades, video management system, cameras, etc.)	14.6	Addresses assets in poor condition, safety, and security concerns.

1. Architectural

Architectural systems refer to the functions of a building. Within work centres and stations, Toronto Hydro plans to address issues related to the foundation and building envelope (e.g. brick masonry walls, windows and roofs) and interior finishes (e.g. carpets, walls, ceiling tiles, baseboards, office furniture, office cubicles etc.). Examples of repair work to be undertaken under this category include the renovation of the Trades Training Area, superstructure and concrete/masonry repairs at 500 Commissioners and architectural repairs and remediation work at distribution stations.

a. Renovating the Trades Training Area at 500 Commissioners Work Centre

The Trades Training area at 500 Commissioners will be renovated to accommodate increased class sizes and to permanently remove the slip-trip-and-fall hazards, as demonstrated in Figure 3 (left picture), below. Currently, Trades Training classes are over-crowded due to the size and design of the current training area. This issue is likely to be exacerbated in the next few years due to the increase in Trades recruitment resulting from retirements.[4] In addition, the audio visual equipment is inadequate and non-functional as the wiring is breached behind the training room walls and training time is lost, reducing productivity, due to attempts to revive this equipment or to bring in the portable projectors/learning aids to continue the training.

b. Superstructure and Concrete/Masonry Repairs at 500 Commissioners Work Centre

Superstructure and concrete/masonry repairs at 500 Commissioners work centre are required for improved safety since there is extensive corrosion in and around its welded joints (see Figure 3 – right picture). The work centre at 500 Commissioners is almost 25 years old. As the building gets

[4] See Exhibit 4A, Tab 4, for a discussion of Toronto Hydro's staffing and recruitment efforts

older, corrosion affects the integrity of the structure which could lead to permanent and irreparable damage.

Figure 3: Tripping Hazard caused by AV Equipment in Trades Training Area (Left) and Rusted Loading Dock Super Structure at 500 Commissioners, Architectural Repairs and Remediation at Distribution Stations (Right)

In 2017, a third party conducted a review of five Toronto Hydro transformer stations (the "Stations Review").[5] The five stations were selected as being representative of Toronto Hydro's other stations, based on size and complexity. The result of the Stations Review revealed that remediation work was required at all five stations to bring them up to the standards mandated by the 2012 Ontario Building Code ("OBC") and the Ontario Fire Code ("OFC"). For instance, deficiencies that were noted include exits signs not being well-defined, stairs non-compliant with safety standards, and inaccessible doors along pathways that pose tripping hazards. The Stations Review concluded that remedial work should be undertaken in order to remediate safety hazards for employees and comply with the OBC and OFC.

Apart from the five stations assessed by the Stations Review, the condition assessments conducted by Toronto Hydro found that a number of other stations also require repair or replacement of their building envelope (e.g. roof, windows, masonry walls, and doors) in order to address risks of water and pest infiltration and structural damage from external elements, all of which could impact the distribution equipment located within. For example, Figure 4, below, illustrates a damaged wall at Etobicoke Neilson Drive Station, which is located directly adjacent to critical distribution grid equipment. If the wall is not repaired, water infiltration will accelerate the corrosion of the distribution grid equipment. Delaying some repairs or replacements may lead to higher operational

[5] Review conducted on Toronto Hydro's Flemingdon, Junction, Allenby, Terauley, and Mountbatten stations.

costs as frequent, repetitive patch-up work may be required to prevent failure of distribution equipment.

Figure 4: Damaged Wall at Etobicoke Neilson Drive Station

2. Fire & Life Safety

Currently, there are 20 stations with Cerberus Pyrotronics – System 3 fire alarm panels (Figure 5), installed in the early 1990s. These fire panels need to be replaced prior to failure as parts for this system are obsolete and difficult to obtain, which may result in increased wait times and additional repair costs. For instance, in May 2016, the power supply to the fire panel located at Wiltshire Station required replacement and took over a week to complete due to the lack of requisite parts. This resulted in additional costs stemming from required personnel keeping watch for fire hazards until repairs could be completed. This additional expense was more than the total cost for parts and labour combined, expenses which could have been avoided through a proactive, scheduled replacement of these outdated fire panels. To address these concerns, five of the 20 Cerberus Pyrotronics – System 3 fire panels are planned to be replaced as part of a planned replacement program during the 2020-2024 period, and their parts will be retained to be used for reactive repairs pending replacement of the 15 remaining panels as part of work programs for future years.

Figure 5: Cerberus Pyrotronics - Fire Panel at Carlaw Station

3. Mechanical and Electrical

Mechanical and electrical assets include Heating, Ventilation and Air Conditioning ("HVAC") systems, elevators, site lighting, electrical panels, building automation system, and power distribution systems in Toronto Hydro's buildings.

The proposed mechanical and electrical work includes replacing the HVAC systems at 500 Commissioners work centre, supplementing the computer room with air conditioners at 14 Carlton, upgrading the lighting at 500 Commissioners, and replacing lighting and sump pumps at certain stations.

a. Replacement of HVAC Systems at 500 Commissioners

Toronto Hydro will replace the original HVAC systems, installed in 1996, on the north side of Building B at 500 Commissioners that are past their useful life and in poor condition (see Figure 6, below). These HVAC systems frequently break down and consume an excessive amount of energy. Failure of building assets such as HVAC systems jeopardizes the functionality of vital operations due to critical equipment not being maintained at required temperatures. Furthermore, the new HVAC systems are much more efficient in regards to electricity consumption. Previously, Toronto Hydro replaced an HVAC system on the south side of the building and, as a result, electricity consumption dropped by 60 percent. Since the original HVAC systems on the north side of the building are past their useful life and in poor condition, they would need major repairs in the future.

Figure 6: Rusted HVAC units at 500 Commissioners

b. *Supplementing Air Conditioners at 14 Carlton*

The Computer Room Air Conditioners ("CRAC") at 14 Carlton's Data Centre require supplementation due to an increase in Data Centre equipment over the last five years. On extremely hot summer days, these CRAC units are showing signs of overloading and lack of capacity.

c. *Upgrading the Lighting at 500 Commissioners*

The interior lighting at 500 Commissioners must be upgraded in order to meet the requirements of the OBC, and damaged exterior lighting fixtures at the 500 Commissioners work centre need to be replaced as they pose a risk of falling on pedestrians and fleet vehicles (see Figure 7, below).

Figure 7: Blown yard light hanging by an electrical wire

In 2017, a third party conducted a review of the lighting at the 500 Commissioners work centre. The review concluded that the lighting in most of the covered parking areas, the warehouse and fleet garage does not meet the requirements set out in the OBC, as illustrated in Table 5 below, and therefore must be upgraded or replaced.

Table 5: OBC Lighting Requirements and Current Lighting Levels at 500 Commissioners

Location of Lighting at 500 Commissioners	Existing Lighting Levels	OBC-Required Lighting Levels
Building A - Warehouse	193 Lux	300 Lux
Building D - Fleet Garage	230 Lux	300 Lux
Building C-Lower Level Parking	37.4 Lux	50 Lux

d. <u>Lighting Replacement at Stations</u>

In addition to the work centres-related mechanical and electrical repairs, damaged or rusted lighting will also need to be replaced at various stations. Stations' lighting poses safety (i.e. trip-and-fall) hazards due to inadequate lighting levels and security concerns (e.g. trespassing, vandalism, and graffiti). Inadequate or damaged lighting as demonstrated in Figure 8, below, also attracts wildlife, which can lead to pest infestation and damage to distribution grid equipment.

Figure 8: Damaged Exterior Light at Etobicoke Hartsdale Station

e. <u>Sump Pump Replacement at Six Stations</u>

In 2017, a third party completed an assessment of the existing water infiltration and sump pump systems at various Toronto Hydro stations (the "Sump Pump Review"). The Sump Pump Review concluded that 15 sump pumps will need to be replaced at six stations. In addition, the Sump Pump Review also identified that several of the existing sump-pumps are of a residential-grade and not suitable for commercial use. Failure of these non-commercial grade/poor condition sump pump systems (see Figure 9 – left, below) could lead to station flooding, resulting in significant reactive repair costs and power outages for thousands of customers. For instance, in January 2018, Dupont Station was flooded due to a residential-duty sump pump failure (see Figure 9 - right, below). The sump pump was similar to the ones reviewed as part of the Sump Pump Review, and the pump has since been replaced with a commercial-duty sump pump. Toronto Hydro plans to take a proactive approach to replacing the remaining at-risk residential grade sump pumps to avoid damage to the station or grid distribution assets located within the stations.

Figure 9: Heavily Corroded Sump Pump at Toronto Main Station (Left) and Dupont Station Flood due to Sump Pump Failure in January 2018

4. Civil

Civil work refers to exterior access ways and walkways, including pavement, driveways, and parking spaces. Many surfaces at both work centres and stations are in poor condition and in urgent need of repair to prevent tripping hazards (see examples in Figure 10).

Examples of the major work proposed under this category include asphalt/concrete pavement and driveway repairs at more than 20 distribution stations, truck parking garage ramp repairs, and fleet vehicle parking repaving at the 500 Commissioners work centre.

Figure 10: Damaged Pavement at Junction Station (Left) and Damaged Concrete at 500 Commissioners Gate Entrance (Right)

5. Plumbing

Plumbing assets include fixtures, showers, drinking water units, and water heaters. Some of the major proposed work in this category includes replacement of corroded or damaged water heaters at ten stations that have both surpassed their useful life and are in poor condition. Any further delays on replacement may result in leakage or asset damage given their close proximity to grid distribution assets. In addition, the plumbing fixtures in Buildings A and D at 500 Commissioners require replacement as they are past their useful life, in poor condition, frequently break-down and consume high volumes of water.

E8.2.3.2 Security Improvements

This section sets out the work to be undertaken to improve the physical security infrastructure at Toronto Hydro.

1. Security Improvements

With extensive focus on the Smart Grid across Ontario, information technology ("IT") infrastructure is becoming increasingly critical in grid distribution equipment. Toronto Hydro's stations contain Smart Grid/Supervisor Control and Data Acquisition ("SCADA") assets in areas with the highest population density in Canada, posing heightened security risks of hacker infiltration. Utility companies are targets for security breaches because of the critical role they play in the operation of essential services (e.g. hospitals, public transit, and traffic management) and the vast databases of confidential customer information they possess.

In 2016, the OEB conducted a review of the state of cybersecurity of the (non-bulk) electrical grid and associated business systems.[6] As a result of this review, the OEB issued the Cyber Security Framework (the "Framework") which is designed to allow licensed utilities, such as Toronto Hydro to assess their inherent cyber security risk, define their benchmark objectives, and measure progress towards those objectives and report back to the OEB. To ensure mandatory compliance with the Framework, on March 15, 2018, the OEB amended its Distribution System Code to require all licensed distributors to report on the status of cyber security readiness.

To ensure continued compliance with the Framework, Toronto Hydro requires investments in physical security infrastructure. The Framework recommends a number of controls to be in place to limit access to assets and associated facilities to authorized users only.[7] Toronto Hydro plans to implement the Framework controls through a two-pronged approach: (1) [redacted] (2) [redacted] Therefore, the security improvement work performed under the Program ensures the protection of Toronto Hydro assets (i.e. employees, information, equipment, business operations and building infrastructure) through the implementation and administration of new and enhanced security standards, including:

- the implementation, maintenance and continuous lifecycle management of modern commercial security systems and technology as per standards developed by Toronto Hydro and security subject matter experts;
- the proactive monitoring and control of these systems and technology; and
- the systematic and phased application of security management policies and procedures across all Toronto Hydro sites. In the 2020-2024 plan period, two work centres, and ten stations will receive the [redacted]

[6] EB-2016-0032, OEB Letter, "Protecting Privacy of Personal Information and the Reliable Operation of the Smart Grid in Ontario (February 11, 2016), available at: < https://www.oeb.ca/industry/policy-initiatives-and-consultations/protecting-privacy-personal-information-and-reliable>.
[7] Supra note 6, Appendix E, page 5.

a. CCURE System Expansion

[redacted]

b. Video Management System

[redacted]

c. Automatic Key Management System

[redacted]

[8] Certain employees are provided with secondary roles in the case of emergencies. These roles dictate access-levels.
[9] The sites proposed to receive the Key Management System were chosen to provide the best control of issued keys for station assets.

[redacted]

[redacted]

d. ***Enhancement of the Security Operations Centre***

[redacted]

[redacted]

These improvements will help Toronto Hydro achieve the physical security and continuous monitoring controls identified in the Framework, thereby reducing the risk of an unauthorized user gaining access to physical IT equipment and secure sites.[10] For instance, the enhanced SOC will contain automatic alarm capabilities for physical security alerts in response to unidentified or unverifiable access to information technology assets, e.g. server rooms. In addition, the SOC enhancement will allow for monitoring of the Building Automation System ("BAS") to ensure that critical system alarms will be immediately communicated to the relevant employees. For instance, a high sump pit level due to sump pump failure is a critical notice and would be communicated

[10] Supra note 6, Appendix E, page 18.

immediately to the appropriate stakeholders so that it can be addressed in a prompt and efficient manner.

E8.2.4. Expenditure Plan

The historical and forecast program costs for the Program are set out in Table 6, below. The work performed under the work centres and stations categories will be completed based on priority and balancing of the workload over the 2020-2024 plan period. Specifically, for the work centre category, projects will take place primarily in 2020 and 2021 as these projects involve like-for-like replacements which do not require construction permits. For the stations category, approvals and permits will be obtained in 2020 and 2021 for projects that will take place in 2022, 2023 and 2024. These will typically be larger projects requiring extensive design, permits, and stakeholder approvals (e.g. Hydro One, City of Toronto, TTC, etc.). Overall, the largest expenditure in both the work centres and stations categories will be in the areas of Architectural and Fire & Life Safety, which accounts for 75 percent of the required capital expenditure, primarily due to the fact that more than 80 percent of Toronto Hydro's stations are over 40 years old and require significant Architectural and Fire & Life Safety renovations to maintain functional operation.

2021 will be the highest spending year in the security improvements category to ensure that the outlined security concerns are addressed as quickly as possible while also allowing for time in 2020 to plan for the required work.

Table 6. Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Work Centres	11.4	5.3	4.2	0.7	1.1	7.2	2.9	0.2	1.1	1.7
Stations	3.2	2.8	1.6	1.1	1.1	2.9	3.8	8.3	9.0	8.7
Security Improvements	0.7	0.9	0.5	0.4	0.4	1.5	5.1	3.6	2.2	2.2
Total	**15.3**	**9.0**	**6.3**	**2.2**	**2.6**	**11.6**	**11.8**	**12.1**	**12.3**	**12.6**

E8.2.4.1 Work Centre and Stations

Starting in 2016, work centres and stations building assets were assessed and received a condition rating of poor, fair or good. Assets that received a poor condition rating will be addressed within the 2020-2024 plan period. Assets in fair condition will be closely monitored and/or maintained under a preventative maintenance program. Finally, assets in good condition are not planned for any repairs in the 2020-2024 period. Toronto Hydro will only replace assets that are past their useful life and are in poor condition. This means that assets that are past their useful life but are in fair or good condition or are "run-to-fail" will defer $11.3 million in asset lifecycle costs.

The assets categorized as being in poor condition are assigned a priority rating based on the Facilities Asset Management Strategy.[11] The priority ratings are used to ensure that the Program is targeted on the most critical assets first:

- **Priority Rating 1:** Critical life safety assets (e.g. Fire & Life Safety systems, sump pumps).
- **Priority Rating 2:** Assets that provide building functionality (e.g. doors, windows, roofs).
- **Priority Rating 3:** Assets that are run-to-fail and/or low impact (e.g. baseboard heaters). These assets are to be replaced only when they fail even if they are past their useful life and are readily available for replacement as needed.
- **Priority Rating 4:** Assets that provide cost effective upgrades to existing systems and should be planned if there is an existing project going on in the area.

E8.2.4.2 Security Improvements

There is an increase in spending over the 2020-2024 plan period as compared with the 2015-2019 plan period. [redacted]

Security improvements can be broken down into four key areas: access control (including intercom and duress stations), Security Operations Centre, physical security improvements, and CCTV improvements. A breakdown of the required capital spending in each of these areas can be viewed in Figure 11, below. The majority of the security improvements funding is planned for 2021 since that is the primary year of the access-control conversion (i.e. ISL to CCURE). The remaining items will be addressed throughout the plan period.

[11] See Exhibit 2B, Section D5 for more details

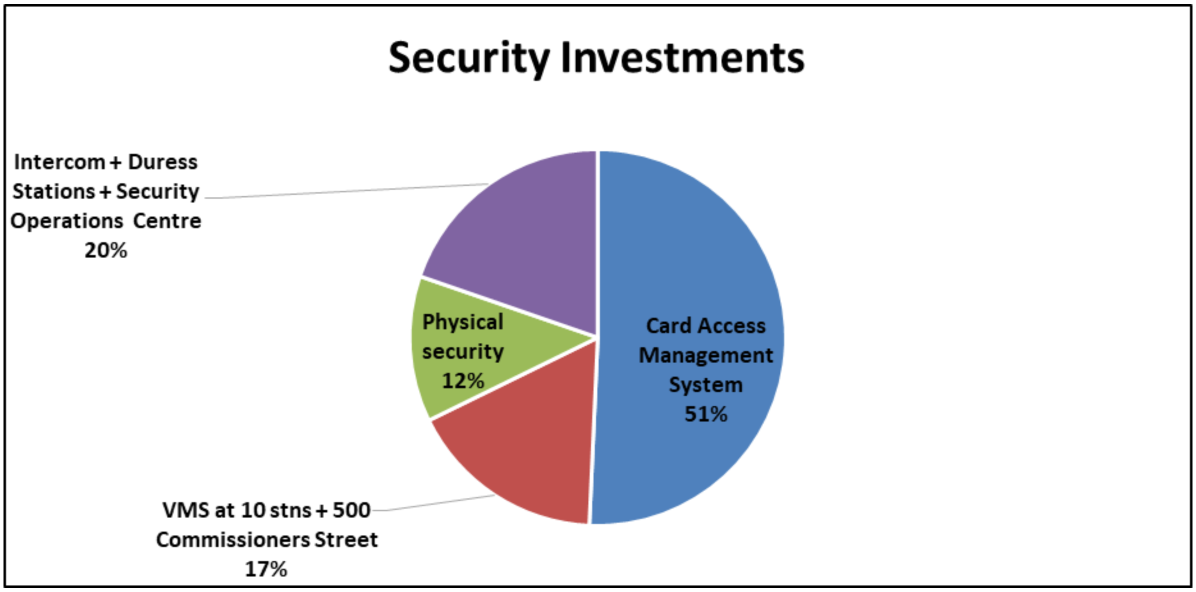


Figure 11: Security Related Investments

The Program's work sequencing will be driven by the following factors, in order of priority:

1) **Health & Safety**: Upon review, should a project be deemed a risk to the health or safety of employees or customers, it will become priority.
2) **Protecting Critical Functions and Assets:** Toronto Hydro's stations house electrical distribution equipment, which are critical to distributing electricity to customers. Toronto Hydro's work centres are critical to maintaining business continuity. Critical business functions housed within Toronto Hydro-owned facilities include Customer Care Call Centre, Control Centre, and IT Infrastructure (Data Centres).
3) **Lifecycle Costs:** Assets which incur high-operational costs will be replaced so long as their replacement is expected to provide operational savings in future years. For example, HVAC components in fair condition which breakdown frequently incur high-operational inspection and repair costs. Replacement would be considered in these cases.
4) **Cost-efficiency and Grid Management:** Remediation work in stations frequently require the assets to be fully de-energized in order for employees to work safely. Therefore, projects in this Program will be planned and executed alongside capital projects in the stations in order to minimize the number of outage requests at a station and its overall downtime.
5) **Planning and Risk Assessments**: Some of the work within the Program involves design and construction around high-voltage equipment in buildings with heritage preservation status.

Due to these complexities, these projects need to be planned accordingly, with risks identified and mitigation plans created.

E8.2.5. Options Analysis / Business Case Evaluation ("BCE")

E8.2.5.1 Option 1: Run-to-Fail Approach

Under the run-to-fail approach, Toronto Hydro would delay necessary investments in work centres and stations and would perform replacements and repairs on a reactive basis, once an asset fails. Since the majority of assets that are end of life and in poor condition are categorized as Priority 1 (critical) and Priority 2 (building functionality), this approach would significantly impact Toronto Hydro's operations should they fail. Furthermore, the OEB's Cyber Security Framework stresses the importance of physical security to support the objectives of cyber security for utilities. Some of the effects of instituting a run-to-fail strategy include:

- **Business Disruptions:** Fire alarm panels, large HVAC units and heritage station assets can only be addressed through planned replacements as they involve engineered design, analysis, long-lead material purchases, and/or custom built materials (i.e. in support of heritage preservation). This strategy will lead to business disruption as facilities-related assets support the work environment of Toronto Hydro employees and are essential to business continuity (i.e. Control Centre, Data Centre, and Grid Response). For instance, an unexpected asset failure in the main Control Centre could halt the ability of crews to work safely.
  Further, failure to improve and enhance the current security standard could increase the risk of the following: [redacted]
- **Failure of Toronto Hydro Grid Distribution Assets:** Failure of Priority 2 assets (i.e. building functionality such as roofs and windows) could directly affect grid reliability. For instance, proactively maintaining the integrity of station roof surfaces protects grid distribution equipment from water infiltration. Distribution equipment is highly susceptible to water damage and can lead to outages if compromised, directly affecting Toronto Hydro

customers. The top priority for Toronto Hydro's Key Account customers, as per the 2017 Customer Engagement Survey, is reliable power supply.

- **Asset Lifecycle Management:** Without proactive replacement, Priority 1 and 2 assets that are in poor condition will fail unexpectedly. The cost associated with unexpected failures and reactive repairs often outweighs the cost of proactive repairs due to the fact that reactive repairs generally require additional scope and premium time. For example, damage to Annabelle Station's shingles was not addressed proactively or in a timely manner and led to the necessity for mold abatement, which on its own cost 1.8 times more than the cost to replace the roof shingles.

Figure 12, below, shows the progression of asset condition if no action is taken in the 2020-2024 plan period. As more assets transition from good and fair to poor condition, there is increasing risk that lifecycle management costs will rise as well.

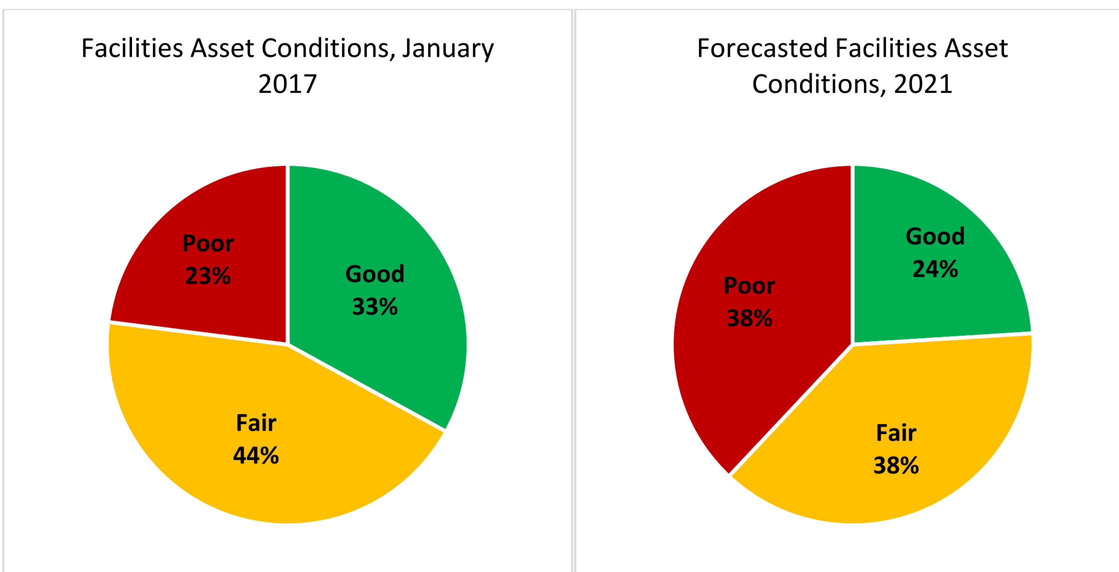


Figure 12: Progression of Asset Conditions under "Run-to-Fail" Approach

- **Safety Hazards:** There are increased safety hazards under this approach due to assets in poor condition and unexpected failure. For example, the Stations Review identified safety gaps directly contradicting requirements under the current OBC. For instance, in the event of an emergency, the exit routes are not easily identifiable and may result in entrapment. In addition, water infiltration in stations creates a risk of electrocution hazards to on-site personnel, health and safety considerations with standing water and mould, and compromises the integrity of the building. Lastly, lighting in various areas at 500 Commissioners is in poor condition and beyond useful life. Some areas do not provide minimum lighting levels required under the OBC.

[redacted]

E8.2.5.2 Option 2 (Selected Option): Preventative Maintenance and Planned Replacements of End of Life and Poor Condition Assets and Investing in Security Improvements at Certain Toronto Hydro Work Sites

This option will cost Toronto Hydro approximately $60.4 million. The benefits of implementing this option include:

- **Utilizing Capital Funds for Priority Assets:** More than 90 percent of capital funds will be spent on addressing Priority 1 (critical) and 2 (building functionality) assets.
- **Minimized Asset Lifecycle Costs:** Assets that have surpassed their useful life, but are in good or fair condition, or are run-to-fail will not be replaced. This strategy will defer $11.3 million in asset lifecycle costs.
- **Legislative Compliance:** Toronto Hydro can maintain compliance with mandated requirements by ensuring that lighting, HVAC, flooring and stairs hazards, etc. and other deficiencies are addressed.
- **Competitive Procurement Pricing:** Planned replacements will help Toronto Hydro by utilizing a competitive bids process, resulting in favorable acquisition costs for goods and services while maintaining quality of work and process integrity.

- **Stakeholder Management:** The planned replacement policy would provide sufficient time to identify and involve all stakeholders to the planned work. This would also include obtaining appropriate approvals and permits for the work involved.
- **Proactive and Responsive Security Monitoring and Control Systems:** By having a proactive approach to security systems, the physical threats to Toronto Hydro's assets can be minimized by having a real-time response to threats as they occur. This would also aid in providing recorded visual evidence.
- **Quick Response to Grid Emergencies:** The capability for emergency activation of access-levels would support automatic-access to predefined areas in work centres or stations. This is expected to result in faster response times and more efficient organizational coordination when addressing grid emergencies.

[redacted]

E8.2.5.3 Option 3: Preventative Maintenance of Assets and Replacements of All End of Life Assets and Investing in Security Improvements at all Toronto Hydro Work Sites

This option considers replacement of all assets that are end of life, irrespective of asset condition as well as replacing Video Management System hardware and software at all stations. This approach also conducts preventative maintenance on all assets, without a regard for asset function or criticality. This option will require approximately $113.5 million in funding.

Some of the main cost drivers under this option include:

- All assets at the end of life will be replaced at a cost of $53 million irrespective of asset condition;
- Emergency exits and lighting will be remediated at all stations and work centres at a cost of $38 million; and
- Security upgrades across all Toronto Hydro properties at a cost of $22.5 million.

Some of the consequences of instituting this approach include:

- **Increased Funding Request:** Funding required to implement this approach is $113.5 million and this will increase costs for ratepayers.
- **Increased Reliability of Assets**: Since all assets will be replaced at their end of life, replacement will improve their reliability and reduce the financial burden of reactive maintenance.
- **Operational Savings**: When assets require reactive maintenance less often, operational spending would decrease.
- **Optimized Working Environments:** Advanced lighting systems across all sites, HVAC retrofits, and renovations would refine controls and offer greater employee comfort.
- **Improved Security Monitoring and Control Systems:** [redacted]

E8.2.5.4 Evaluation of Options

When comparing the different options available to Toronto Hydro, the utility has chosen Option 2 as the prudent and preferred approach since it ensures continued reliability of the grid, reduces overall asset lifecycle costs, and the safety of employees and the public. It also ensures the necessary security infrastructure is in place to continue compliance with the OEB Cyber Security Framework. In addition, reactive repairs of assets under Option 1 is not cost-effective since failure would affect public and employee safety, and Toronto Hydro's business continuity. Option 3, on the other hand, does not have the same flaws and would provide a number of benefits such as decreased operational costs, optimal work environment, and an increase in reliability of assets. However, the significant cost escalation for ratepayers does not make this a viable option.

Option 2 is also the most cost-effective solution that ensures Toronto Hydro continues to maintain the level of security required to safeguard an essential service. The majority of assets planned for replacement in the 2020–2024 plan period are at the end of their useful life and in poor condition. These assets are related to critical systems and building functionality, and therefore utilizing a run-to-fail approach would not be acceptable since these critical assets are design-heavy and require engineered solutions, long lead times, and City permits.

On the other hand, proper project planning and constrained spending (i.e. the proposed approach) over the 2020-2024 plan period is expected to provide many benefits, including:

1) A balanced investment approach to align with resource capacity;
2) Minimization of business interruptions;
3) Optimization of Toronto Hydro Procurement Strategy in order to receive competitive prices for services; and
4) Sufficient time for comprehensive design, permit, and purchasing.

Lastly, applying a restrained approach under Option 2 and utilizing the Facilities Asset Management Strategy to only replace assets that are end of life and in poor condition would be the more cost-effective solution for ratepayers.

E8.2.6. Execution Risks & Mitigation

The Program is vulnerable to several risks that could affect the planning and timing of repairs and replacements. The risks include:

- Delays in obtaining the necessary approvals and permits to begin executing the work programs may delay the start or completion of projects. To mitigate against this risk, Toronto Hydro will utilize subject matter experts to work with the necessary stakeholders in order to obtain approvals and permits in a timely manner. In addition, Toronto Hydro will initiate the process as early as possible to ensure permits are obtained for the project's scheduled execution timing, mitigating delays.
- Legacy environmental conditions (e.g. asbestos or PCBs) might require further testing and analysis, which may affect project budget and execution schedule. To mitigate against this risk, Toronto Hydro will seek subject matter expertise (consultants and/or engineers) for a thorough review of actual field conditions in high-risk locations prior to developing a project plan and incorporate these findings during the procurement process to limit the cost escalation of abatement work through time and material.

E8.3 Fleet and Equipment Services

E8.3.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 19.1	**2020-2024 Cost ($M):** 42.5
Segments: Fleet and Equipment Services	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Reliability, Environment, Safety, Financial	

The Fleet and Equipment Services program (the "Program") is responsible for the procurement, maintenance, and disposal of vehicles and equipment that are needed to support Toronto Hydro's functional and operational needs. The Program's primary objective is to manage the Program's assets to the lowest overall lifecycle cost, while ensuring asset reliability and employee and public safety. Capital investments within the Program are grouped into two categories: (1) vehicles: which includes, (a) heavy duty vehicles, used as a primary tool to perform distribution work, and to transport operators and equipment; and (b) light duty vehicles, which are fully equipped for employees to inform, manage and monitor distribution work; and (2) vehicle and employee equipment (e.g. forklifts, trailers, telematics systems, boom lifts, protective gear, etc.). The Program and its constituent segments are a continuation of the activities described in the Fleet and Equipment Services program in Toronto Hydro's 2015-2019 Rate Application.[1]

Toronto Hydro relies on its fleet of vehicles to support functional needs and performance requirements associated with executing a complex and dynamic capital and maintenance program. An insufficient or unreliable fleet can negatively impact utility performance, such as reliability and employee productivity. In addition, as vehicle fleets age, they incur higher operating expenses due to increasing levels of reactive repairs. Therefore, the Program ensures that capital investments are made at a level and pace that allow asset maintenance, repair and capital costs to be minimized. An optimally timed vehicle replacement strategy also ensures that the appropriate level of vehicles are available to support system maintenance and capital investment plans.

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 2B, Schedule 8.1.

To ensure that the vehicles are replaced in a cost-effective manner, Toronto Hydro utilizes the Life Cycle Analysis ("LCA") approach to identify the capital investment candidates for future replacements and bases its decision to replace or dispose of the vehicle on the actual asset condition assessment. The LCA provides empirical justification to identify the best time to replace vehicles in terms of age, mileage or other pertinent factors. As the age of a vehicle increases, ownership costs decline and operating costs increase. As such, the optimal time to replace a vehicle is before the point where the operating costs begin to outweigh the decline in ownership costs. To assist with determining the LCA, Toronto Hydro retained a third party consultant to undertake a comprehensive study of Toronto Hydro on-road vehicle fleet and to provide recommendations regarding the optimal replacement age of the fleet vehicles. Toronto Hydro leverages the analysis to plan its future capital replacements during the 2020-2024 plan period.

Figure 1: Toronto Hydro Fleet

Although the LCA identifies the optimal age for vehicle replacements for the purposes of expenditure planning, Toronto Hydro replaces vehicles according to the results of vehicle condition assessments. Because a replacement cycle varies depending on the vehicle make, model year, equipment design, operating environment or even by how the operator uses the vehicle, some vehicles that are in poor condition or unsafe may require replacement before the criteria is met, and alternatively, some vehicles that exceed the criteria may be in good condition and not warrant replacement. As such, the vehicles forecasted for replacement in accordance with the LCA, also undergo condition assessments performed as part of the regular vehicle inspections. This forms the basis of Toronto Hydro's vehicle replacement and disposal decision-making.

Prioritization within the Program reflects the importance of the vehicle class to performing core distribution work, the lead time required to procure the asset, cost, and the level of customization required. As such, capital plans are created by first scheduling the heavy duty vehicle replacements in their recommended replacement year, followed by light duty vehicles. Equipment is scheduled on a more ad-hoc basis. It is more economical and efficient to procure vehicles in batches of approximately five to ten units, therefore asset replacements are shuffled between years within a five year plan to assist with balanced spending during the years.

Over the 2020-2024 plan period, Toronto Hydro will focus primarily on the replacement of heavy duty vehicles that are or will be due for replacement. Owing primarily to the fact that heavy duty vehicles are eight to ten times more expensive than light duty vehicles and due to the increase in foreign exchange rates that has led to an escalation in asset price, the requested Program funding over the 2020-2024 plan period is higher than the 2015-2019 period. Nevertheless, Toronto Hydro continues to implement various mitigation measures to minimize the impact of these costs. For instance, Toronto Hydro has taken steps to reduce its overall fleet size from 660 units[2] down to 588, thereby, reducing the operating costs of running a larger fleet.

In addition, the investments in Toronto Hydro vehicle fleet can produce the following benefits:

- Minimization of total vehicle costs;
- Minimization of fleet downtime due to repairs, and a corresponding increase in fleet reliability;
- Increase in vehicle efficiency, i.e. lower fuel consumption and idle reduction;
- Improvements in shop efficiency as less labour will be required to maintain new vehicles and focus can be on older vehicles;
- Reduction in environmental impacts such as reduction in greenhouse gases emitted as well as a reduction in the maintenance fluids used; and
- Increased employee and field safety as newer vehicles are equipped with new safety technology.

[2] I in EB-2014-0116, Toronto Hydro reported a fleet size of 660 units, including cars, pickups, bucket trucks, and other vehicles. See EB-2014-0116 Exhibit 2B, Section E8.1 at page 5.

E8.3.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Ensuring work crews have the necessary vehicles and equipment to perform distribution work when required; and ○ Ensuring that the fleet is in good running order and the assets are replaced before critical equipment failures arise that necessitate lengthy and costly offsite repairs.
Environment	• Contributes to Toronto Hydro's environmental objectives by aiming to reduce GHG emissions associated with fleet fuel consumption by: ○ Utilizing hybrid and electric vehicles and biofuels where possible; and ○ Implementing anti-idling technology, GPS reporting used to drive changes in driver behaviour, and the use of biofuels.[3]
Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by helping to ensure employees are working safely with minimal exposure to hazards.
Financial	• Contributes to Toronto Hydro's financial objectives as measured by the total cost and efficiency measures by: ○ Managing fleet and equipment assets to the lowest overall lifecycle cost; and ○ Mitigating fuel expense by aiming to reduce fuel consumption through a combination of utilizing hybrid and electric vehicles; idle-reduction technologies; and adhering to recommended vehicle lifespans.

[3] The use of technology to drive these results is limited by funding and classes of vehicles where the Return on Investment is justifiable.

E8.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Safety, Reliability, Business Operations Efficiency

E8.3.3.1 System Maintenance and Capital Investment Support

The trigger driver for this Program is the need to ensure that Toronto Hydro continues to have access to vehicles that support system maintenance and capital investment activities during the 2020-2024 plan period and beyond. Toronto Hydro requires access to vehicles and equipment that meet current and future functional requirements to transport employees and materials to and from job sites, to perform work onsite, and provide onsite working area and shelter. Toronto Hydro's fleet consists of many types of vehicles that are designed for multiple purposes. On the job-site vehicle uses include, but are not limited to, lifting and positioning material, storing material, preparing material for installation, acting as a planning station and serving as shelter. Fleet vehicles must be available to support these functions in a safe, reliable, and operationally efficient manner.

Heavy duty vehicles are a primary means of transporting equipment for distribution work. Light duty vehicles facilitate the engineering and management functions of distribution work. Associated equipment assets are used to perform lifting and towing, and include operator safety implements, such as network protection relays, rubber gloves, and gas monitors. Over time, these units are subject to wear and tear that impact vehicle safety, reliability, and operational efficiency. In addition, operational needs and requirements change over time in a manner that necessitates certain vehicle and equipment types, technologies and configurations that are not found in the utility's existing fleet.

If the age profile of the fleet surpasses the target age identified in the LCA, reliability of these assets may become compromised, posing risks to the timeliness and reliability of distribution work. When the average age of the fleet exceeds the target age, the vehicle-related parts and services operating costs also begin to increase significantly. It is expected that the vehicle-related operating costs will also continue to escalate as the average age of the fleet increases.

E8.3.3.2 Safety

As vehicles age, there is an increased risk of safety issues such as structural and component failure, and electrical faults, caused by a number of factors, including corrosion. Toronto Hydro vehicles are continuously used throughout the year and spend the majority of the time outdoors in direct exposure to the weather and external elements. In addition to high levels of humidity throughout the year which can cause corrosion, road salt used on city streets and highways is of particular concern as it can lead to corrosion that damages and weakens the frame of the unit over time. The frame is the main structure of a vehicle to which all running gears are fastened, and supports the entire weight of the vehicle excluding the wheels, suspension, and some steering components. Severe rust to the frame can lead to breaks while under load, e.g. during a lift operation, cable pull, or material loading. Frame weakness can also decrease the ability of the vehicle to withstand crashes, thus jeopardizing the safety of the operators and the general public.

As shown in Figure 2 and Figure 3 below, corrosion can also appear on vehicle body panels, causing them to be weak and brittle. Brittle panels are subject to breaking, leaving sharp edges or presenting a potential fall hazard if the rusting occurs on a step, handle, or vehicle floor.

Figure 2: Corrosion on Cube Van Steps

Corrosion may also occur on components that are critical to the operation of the vehicle, such as transmission and brake lines, that are often not observable between vehicle services. Rust on these components results in weak spots that have the potential to rupture and leak, and/or cause failures while in use. For example, a transmission line rupture could result in a seized transmission. If this occurs while in motion, the operator is at risk of losing control of the vehicle. Further, brake line leaks can result in brake failure, possibly leading to a loss of control.

Costly transmission replacements are a determining factor in taking a vehicle out of service as the repair costs can exceed the netbook value and market value of the vehicle.

Figure 3: Underbody Corrosion on Bucket Truck

As mentioned above, regular use of the fleet over time can lead to the failure of critical components that are not readily serviceable or observable by maintenance staff. Components such as the hydraulic hoses running through an aerial cannot be directly inspected at service intervals. As the hoses age, they become less flexible and more brittle. Hose failure results in hydraulic fluid leaks to the environment, and could also result in an inability to lower an employee operating a bucket to the ground. Rescuing an employee from an aerial bucket presents a potential risk to the employee in the bucket, other field employees who are assisting with the operation and the public.

Lastly, components designed to protect electrical circuitry can become compromised as a vehicle ages and wear down with regular use, leading to potential electrical failures. The longer a vehicle is in service, the more inevitable this failure becomes. Electrical failures could lead to the disabling of auxiliary safety lighting systems and onboard equipment which are required as field staff perform their distribution functions.

E8.3.3.3 Reliability

Unreliable or unavailable vehicles adversely impact Toronto Hydro's ability to provide acceptable levels of reliable service, and could also result in lost productivity or a disruption to construction and/or maintenance plans. As is discussed elsewhere in this Program, Toronto Hydro vehicles generally require increasing maintenance as they age. In addition, even with regular maintenance, as part of regular wear and tear activities, vehicles are more likely to fail while in use or will need to be held out of service for repairs following an inspection. Furthermore, parts availability decreases over time, and there is a risk of make and model obsolescence. As a result, there is an increased probability that the vehicle will be taken out of service for longer periods of time, while Toronto Hydro procures the requisite parts.

E8.3.3.4 Business Operations Efficiency

Toronto Hydro's utilization of a vehicle's LCA is intended to minimize the operating costs of the fleet relative to the cost of ownership. As vehicles age, ownership costs (such as purchase costs and cost of capital) decrease as operating costs (such as fuel, maintenance costs, downtime) increase. At some point in the asset's life cycle, the operating costs begin to outweigh ownership costs. The total life cycle vehicle costs are at their lowest at a point in time just before operating costs exceed ownership costs. Vehicle replacement at that point in time minimizes total vehicle costs. As vehicles age, performance such as fuel economy and lifting efficiency tend to decline while emission tends to increase. New vehicles generally entail lower maintenance costs in early years, as they tend to experience less failures requiring repairs.

E8.3.4 Expenditure Plan

Table 4: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Heavy Duty Vehicles	2.2	2.9	3.3	1.7	1.7	5.8	6.6	7.2	7.4	6.5
Light Duty Vehicles	1.3	0.8	0.3	1.5	1.5	2.7	2.2	1.2	1.2	1.1
Equipment	0.6	0.1	1.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1
Total	**4.1**	**3.7**	**4.7**	**3.3**	**3.3**	**8.6**	**8.9**	**8.5**	**8.7**	**7.8**

Toronto Hydro's expenditure and asset replacement planning begins several years in advance, primarily due to the lead time required to procure vehicles. To identify the candidates for future replacements, Toronto Hydro utilizes LCA and asset condition assessments collected during vehicles inspections. As mentioned previously, a LCA enables determination of the optimal time to replace vehicles and equipment based on age, mileage or other pertinent factors.

As vehicles age, ownership costs decrease, and operating costs increase. In this context, operating costs includes maintenance, loss in driver productivity from reduced vehicle reliability and the impact of increased fuel consumption by older vehicles. As the summation of all ownership and operating costs, life cycle costs are determined by modeling actual and anticipated ownership and operating cash flows for a particular vehicle over the life of a vehicle. The projected costs are then used to determine the replacement cycle that results in the lowest overall life cycle costs. The time window in the cycle in which this occurs is the optimal point at which to replace a vehicle. This optimal replacement point is given primarily in terms of age in years.

Figure 4: Toronto Hydro Heavy Duty Vehicles

To assist with the LCA, Toronto Hydro retained a third party consultant to undertake a review of Toronto Hydro's on-road vehicle fleet and to provide recommendations regarding the optimal replacement age of the fleet vehicles. The review identified: (i) the age at which a vehicle should be replaced; and (ii) when replacement should occur (i.e. ideally before costs rise and reliability/safety is reduced and before major capital investment is required).

Using Toronto Hydro's historical costs from 2013 to 2016, the review provided its life cycle analysis recommendations for Toronto Hydro's vehicle fleet, which are summarized in Table 6, below. The conclusions reached in the review include an increase in the lifespans of many light duty vehicles, and a decrease in the lifespans of some heavy duty vehicles.

Table 5: Life Cycle Analysis Replacement Criteria

Priority	Segment	Vehicle Type	2013 LCA (Years)	2017 LCA (Years)	Net	Considerations
1	*Heavy Duty (HD)*	Cube Van	12	12-15	↑	Heavy duty vehicle replacements are routinely evaluated on an individual basis.
1	*Heavy Duty (HD)*	Single Bucket	14	12-16	→	
1	*Heavy Duty (HD)*	Single Bucket -Van Mount	8	11	↑	
1	*Heavy Duty (HD)*	Cable Truck	16	11-14	↓	
1	*Heavy Duty (HD)*	Crane Truck	14	10-14	↓	
1	*Heavy Duty (HD)*	Dump Truck	14	8-12	↓	
1	*Heavy Duty (HD)*	Line Truck	13	13	→	
1	*Heavy Duty (HD)*	Double Bucket Truck	14	14	→	
1	*Heavy Duty (HD)*	Digger-Derrick	13	13	→	
2	*Light Duty (LD)*	Car	6	9	↑	Exceptions: Above average maintenance costs, obsolescence, and usability for the task, poor reliability, excessive downtime, and lack of parts.
2	*Light Duty (LD)*	Cargo Minivan	7	7	→	
2	*Light Duty (LD)*	Passenger Minivan	6	9	↑	
2	*Light Duty (LD)*	Full-size Van	9	10	↑	
2	*Light Duty (LD)*	Pick-Up Truck	9	9	→	
2	*Light Duty (LD)*	SUV	6	8	↑	
3	*Equipment (Eq)*	Trailers	20	20	→	Equipment replacement is on a run-to-failure and/or ad-hoc request basis.

Total life cycle costs and the optimal time for replacement will differ from vehicle to vehicle due to variability in factors such as the vehicle's make, model year, equipment design, initial cost, maintenance costs, and operator usage. Due to this variability, the optimal period is an estimation of the optimal replacement time for most units within the class. Nevertheless, an asset's condition is the final determinative factor in deciding whether or not it will be replaced.

Further, exceptions to the above recommended lifespans may arise depending on specific considerations that may necessitate vehicle replacement ahead of schedule. These considerations include, but are not limited to, average maintenance costs, obsolescence, and unsuitability for the task, poor reliability, excessive downtime and non-availability of parts or accident damage beyond repair. In addition, specialized heavy vehicle replacements are routinely evaluated on an individual basis, irrespective of the schedule. This is primarily due to the critical role heavy duty vehicles play, their costs and the longer lead times required for their procurement.

Expenditure planning for capital replacements begin several years in advance due to the lead time required to procure vehicles. The lead time for heavy duty vehicles, which are of the highest priority and costliest type, is the longest at 1.5-2 years. This is due to the high degree of complexity and specialization required to be responsive to utility functions, as well as the involvement of multiple vendors.

E8.3.4.1 Heavy and Light Duty Vehicles

The number of light and heavy duty vehicles Toronto Hydro is proposing to replace in the current plan period is virtually identical to what was proposed in the 2015-2019 plan period (260 vehicles versus 261 vehicles, respectively).[4] However, in the 2015-2019 period, Toronto Hydro required funding for 62 heavy duty and 199 light duty vehicles. In the current 2020-2024 plan period, Toronto Hydro requires funding for 101 heavy duty and 159 light duty vehicles. In other words, in the 2020-2024 period, Toronto Hydro requires 63 percent more heavy duty vehicles.

For the 2015-2019 period, Toronto Hydro requested funding of $16.9 million for fleet vehicles, $11 million on heavy duty and $5.9 million on light duty vehicles. In the current plan period, Toronto Hydro plans to invest $32.8 million on heavy duty, and $8.2 million on light duty vehicles. Heavy duty vehicles are typically five to ten times more costly than light duty vehicles. As can be seen in Tables 6 and 7, below, an average bucket truck (a heavy duty vehicle) costs $350,000-$450,000, whereas a pick-up or SUV (a light duty vehicle) will cost $35,000-$45,000. In addition, heavy duty vehicles have

[4] EB-2014-0116, Toronto Hydro-Electric System Limited Application (Filed July 31, 2014), Exhibit 2B, Section E8.1, p. 9.

been more significantly impacted by exchange rate fluctuations given that some of the customization requirements are sourced from the U.S.

Table 6: Replacement Costs[5] For Heavy Duty Vehicles for the 2020 to 2024 Period ($ Millions)

Description	2020		2021		2022		2023		2024		Total Cost
	No.	Cost	No.	Cost	No.	Cost	No.	Cost	No.	Cost	
Cube Van	4	0.5	2	0.3	5	0.7	0	0	7	1.0	**2.5**
Van With Aerial Device	3	0.3	0	0	3	0.4	0	0	0	0	**0.7**
Line Truck	2	0.3	0	0	0	0	1	0.1	0	0	**0.4**
Single Bucket Truck	7	2.6	10	3.8	6	2.4	5	1.9	4	1.6	**12.3**
Double Bucket Truck	3	1.3	2	0.9	7	3.1	5	2.3	6	2.7	**10.2**
Cable Truck	0	0	2	1.0	0	0	0	0	0	0	**1.0**
Small Crane Truck	0	0	1	0.3	1	0.3	2	0.5	0	0	**1.0**
Large Crane Truck	0	0	0	0	0	0	1	0.5	0	0	**0.5**
Small Derrick Truck	1	0.4	1	0.4	1	0.4	1	0.4	0	0	**1.6**
Large Derrick Truck	1	0.4	0	0	0	0	2	0.9	1	0.4	**1.7**
Dump Truck	0	0	0	0	0	0	3	0.7	3	0.8	**1.5**
Total	**21**	**5.8**	**18**	**6.6**	**23**	**7.2**	**20**	**7.4**	**21**	**6.5**	**33.5**

Table 7: Replacement Costs[6] For Light Duty Vehicles for the 2020 to 2024 Period ($ Millions)

Description	2020		2021		2022		2023		2024		Total Cost
	No.	Cost	No.	Cost	No.	Cost	No.	Cost	No.	Cost	
Sports Utility Vehicle	25	1.1	0	0	0	0	0	0	0	0	**1.1**
Pick-Up Truck	15	0.8	15	0.7	15	0.9	15	0.9	13	0.8	**4.1**
Minivan - Passenger	3	0.1	0	0	0	0	0	0	0	0	**0.1**
Minivan - Cargo	3	0.1	17	0.8	0	0	0	0	0	0	**1.0**
Full Size Van - Cargo	10	0.5	12	0.6	5	0.3	5	0.3	6	0.3	**2.0**
Total	**56**	**2.7**	**44**	**2.2**	**20**	**1.2**	**20**	**1.2**	**19**	**1.1**	**8.3**

[5] These costs are inclusive of all up-fitting necessary for the job, such as storage bins, partitions, racking, lighting, additional power supply; and any other aftermarket additions required in a particular light duty vehicle.
[6] Ibid.

As vehicles age, they incur higher operating expenses due to increasing levels of reactive repairs. Therefore, if the recommended replacements are not completed during the 2020-2024 period, operating costs for repairs will increase with the escalating average age of the fleet.

E8.3.4.2 Equipment

On-vehicle equipment includes anti-idling technology, GPS units, and laptop mounts installed in vehicles and equipment such as trailers and lifts (scissor lift, forklift, boom lift, vehicle lift). Toronto Hydro currently has 52 trailers and 45 lifts, ranging in age from one to 30 years (average age for both is 12 years). Replacement of this equipment is done on a reactive, or 'run-to-fail' model for the following reasons:

- Equipment generally has long lifespans;
- The variability in frequency of use makes it difficult to forecast replacement based on age or usage;
- Equipment procurement requires short lead times;
- There is little to no customization of equipment required so procurement is prompt;
- There is low safety risk of critical equipment failure; and
- There are similar units available for immediate use if a unit fails critically.

Table 8, below, shows the forecasted costs associated with replacement of equipment on a reactive basis. Equipment is assessed at every preventative maintenance review within a six month period and respective replacement is determined based on unit condition and performance.

Table 8: Equipment Replacement Costs For 2020 To 2024 Period ($ Millions)

	2020	2021	2022	2023	2024	Total
Equipment	0.1	0.1	0.2	0.1	0.1	0.6
Total	**0.1**	**0.1**	**0.2**	**0.1**	**0.1**	**0.6**

Telematics and anti-idling systems helps the Program monitor and continuously improve idling, utilization, driver safety, and diagnostic maintenance. The anti-idle system manages, monitors and provides real-time data to the user on battery voltage, coolant, temperature, idling, anti-theft mode, and engine start/stop. It also provides exceptions reporting on driver behaviour that helps reduce speeding and harsh braking. The use of telematics GPS hardware and software provides benefits in a number of areas, including: real-time tracking of vehicle locations and maintenance indicators[7]; customer complaints investigations and claims (by enabling access to historical tracking of the entire fleet and history of vehicle location); speed profile (notification of speeding based on local speed limit and set data); zone management (home zones based on location of vehicles parked when not in use); and zone creation based on work centre locations to track and optimize arrival and departure of vehicles. Most newly purchased heavy duty diesel vehicles are now equipped with GRIP anti-idling technology to aid in the reduction of idling which will increase lifespan (as it is directly related to the wear and tear of the engines) and decrease GHG emissions. These systems are included in the specifications which the vendors must comply with for purposes of the purchase contract.

Other onboard equipment includes laptop mount kits, for ruggedized laptops used in the field, equipped with pedestal, docking station and wiring needed to power laptops. These mounts are installed in most vehicles (light and heavy duty) to facilitate ergonomically safe use of laptops for onsite crew inspections, site visits and other situations without the need to drive back to the work centre and file paperwork. Ergonomic features (such as dock tilt, spring loaded, telescopic and adjustable base) along with a risk assessment help enhance user safety and performance over time.

Figure 5, below, shows views of a steel lap mount installed in an underground cube van which include a pedestal bolted to the base of the cab along with a docking station, battery protector, and antenna.

Figure 5: Lap Top Mount Installed In Cube Van

[7] For example, engine light on, fuel tank, battery voltage, tire air, GPS not reporting/working, unplugged devices, idling, zoning, trip history, PTO (power off take-off) used for CVOR units (commercial vehicle operation registration).

Prioritization within the Program reflects the importance of the vehicle class to performing core distribution work, the lead time required to procure the asset, the level of customization and/or specialization required, and the cost. Capital plans are created by first scheduling the heavy duty vehicle replacements in their recommended replacement year, followed by light duty vehicles. Asset condition assessment is used to prioritize the replacement of vehicles. Equipment is scheduled on a more ad-hoc basis.

It is more economical and efficient to procure vehicles in batches of approximately five to ten vehicles, therefore asset replacements are shuffled between years within a five-year plan to assist with balanced spending during the year. Replacing in batches and leveling spending in a given year makes it easier for the administration and maintenance teams to ensure work is balanced throughout the lifecycle of the vehicle. The parameters or factors affecting prioritization in long-term capital planning are shown in Table 9, below, by vehicle class.

Table 9: Factors Influencing Capital Planning By Asset Class

	Functional Criticality	Procurement Time	Average Cost/Unit ($M)	Degree of Customization
Heavy Duty Vehicles	High	18-24 months	$0.26	High
Light Duty Vehicles	Medium	6-12 months	$0.04	Medium
Equipment	Low	3-6 months	$0.01	Low

E8.3.5 Options Analysis / Business Case Evaluation ("BCE")

Toronto Hydro considered three options for investments in the Program over the current plan period: (i) run to failure; (ii) managed fleet replacement (the proposed approach); and (iii) replacement of all assets as per the results of the LCA.

E8.3.5.1 Option 1: Run-to-Fail Approach

In the run-to-fail approach, a vehicle would only be replaced once it has completely failed and can no longer perform its intended function. To provide an estimate of the cost impact of this option, Toronto Hydro assumes the average age of the fleet continues to increase by one year for each calendar year. In other words, all fleet assets that are currently owned are assumed to remain in the fleet without turnover. Using Toronto Hydro's current data from 2012-2017, which connects the average age of the fleet with the total vehicle-related parts and services costs, a projection of future vehicle-related costs is forecasted. As shown in Figure 6, below, by year 2024 the average fleet age would be approximately 13.2 years and the corresponding vehicle operating costs would be approximately $11.8 million. This represents a 121 percent increase in operating costs compared to 2017 ($11.8 million versus $5.3 million) – this is more than double the current vehicle related maintenance and repair costs. These cost increases over and above 2017 levels include fuel, parts, labour for maintenance that could have been mitigated with a newer vehicle.

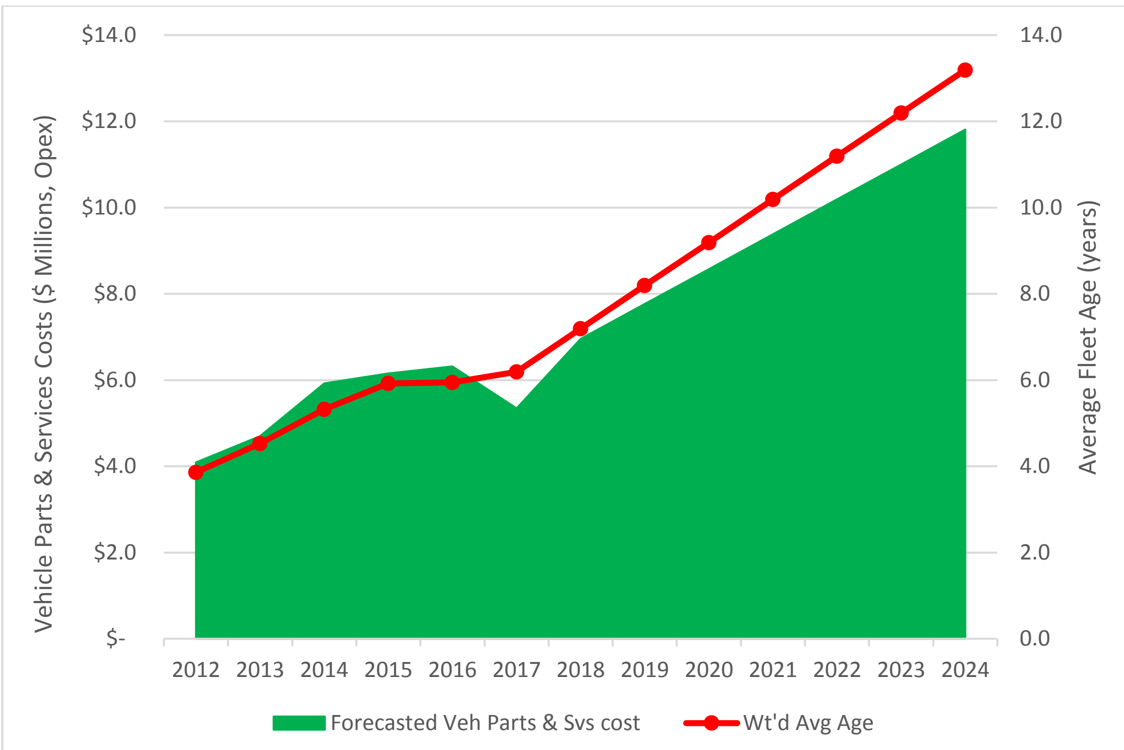


Figure 6: Run-to-Fail Approach - Vehicle OPEX Costs

This option would have the following consequences:

- Unit field failures will likely increase as vehicles age – these field failures will adversely affect field crew productivity and, in some cases, result in Toronto Hydro's inability to conduct system maintenance and capital investment as planned. This will lead to higher labour and support costs (such as permits, penalties for late work completion, additional fuel on account of more frequent trips to and from a work location, etc.).
- The severity of failures is likely to increase, and these failures could potentially become more catastrophic, leading to safety risks, injuries, damage to property or equipment and

environmental spills. For example, hydraulic hoses are more prone to failure over time. A catastrophic hydraulic line failure could, at minimum, result in an employee becoming trapped in a bucket, as well as result in a significant hydraulic fluid spill on to a roadway.

- Running a vehicle to failure would mean that the replacement date is somewhat unpredictable. This would mean being without a specific type of critical fleet vehicle for several months before a replacement is available, given the lead time of a vehicle is between three and 24 months. Distribution work would not be able to be carried out reliably if vehicles are not readily available and in a state of good repair.
- Toronto Hydro operating costs for repairs are likely to increase as parts fail and are replaced. As a vehicle ages, parts will likely become less available, resulting in increasing costs with respect to their purchase. Furthermore, to keep pace with increasing failures, it may be necessary for Toronto Hydro to increase the frequency of preventative maintenance tasks, as well as the number of mechanics it employs and/or the additional external resources it relies on.
- Toronto Hydro may have to increase its vehicle count to maintain similar vehicle availability levels to deliver equivalent service levels to customers. This is because as vehicles age, out of service time will likely also increase due to increasing repair challenges that result from an aging fleet (such as rusted bolts and more significant repairs). To ensure that vehicles are available for use, Toronto Hydro would likely require the use of 'spare' vehicles should the main service vehicles become unavailable on account of maintenance or repairs. In addition, Toronto Hydro may have to rent new equipment for vehicles at a significant cost.
- Replacement for vehicles that have reached total failure require a lead times of up to 24 months for purchase and delivery of specialized vehicles. During this time, Toronto Hydro's ability to perform system maintenance and capital investment may be impaired and/or delayed if alternate vehicles cannot be sourced internally, or via a temporary path such as renting or leasing.

E8.3.5.2 Option 2 (Selected Option): Managed Fleet Replacement

The managed fleet replacement is the proposed approach under the Program. Under this option, Toronto Hydro would undertake a like-for-like replacement of vehicles in line with the fleet replacement considerations outlined in the Expenditure Plan. Utilizing this option, Toronto Hydro is able to bring the average fleet age within +/- 0.5 years of the target average age of five years during the 2020 to 2024 period. By using this approach, Toronto Hydro is able to ensure vehicle-related operating costs do not escalate as a result of equipment failure and other more costly repairs while also having greater assurance that vehicles operate predictably and safely.

This approach will have the following consequences:

- By utilizing this option, Toronto Hydro ensures that replacement of vehicles according to the applicable criteria will optimize the total cost of vehicle ownership on average over time, which translates into savings for ratepayers.
- The managed approach will improve overall vehicle reliability, translating to less downtime, fewer vehicle failures, and resulting in improved field crew productivity;
- Increase in fleet vehicle and equipment performance;
- Improved overall safety of fleet vehicles due to new/improved safety systems; and
- Improved fuel efficiency leading to reduced GHG emissions and fuel costs.

E8.3.5.3 Option 3: Replacement of all Assets According to the Life Cycle Analysis

This option entails replacing all vehicle types according to the exact replacement ages provided for in the LCA review and replacing all trailers over 20 years of age, without taking into account asset condition assessments gathered during routine inspections. Trailers are usually replaced reactively once failure or breakdown occurs. This option would require $56.5 million in funding over the 2020-2024 period.

This option will have the following consequences:

- Pre-emptive mitigation of age-related safety risks and corresponding escalation of repair costs;
- Ensuring adequate availability of similar vehicles to maintain reliability during weather and other emergency events;
- Ensuring adequate availability of vehicles due to an increase in the use of external repair services, which causes vehicles to be out of service for longer durations;
- The overall funding required to implement this option is $14 million more than needed under the managed fleet approach, Option 2, above;
- The number of vehicles to be replaced would also vary greatly year to year, creating logistical challenges with in-servicing and disposing of decommissioned vehicles. In contrast, in Toronto Hydro's proposed approach, the LCA is used as a tool to forecast which assets will

become due for replacement and condition assessments determine exactly which vehicles need to be replaced; and

- Less reliance on condition based assessments. As explained above, there could be an instance when a vehicle that has not met its replacement criteria will need to be replaced due to its poor or unsafe condition. Alternatively, there could be a vehicle that has exceeded its replacement criteria but may be in good condition and, as such may not warrant replacement.

E8.3.5.4 Evaluation of Options

Toronto Hydro has opted to proceed with Option 2, the managed fleet replacement approach, as it is the most cost-effective solution to manage Toronto Hydro's vehicle fleet to the lowest overall lifecycle cost, while ensuring asset reliability and employee and public safety.

Replacing vehicle fleet on a run to failure basis (Option 1) will not only adversely affect field crew productivity and inability to conduct planned system maintenance and capital investment, but it will also more than double the current vehicle related maintenance and repair costs. In addition, Toronto Hydro could have chosen to replace its vehicle fleet according to the exact replacement ages provided for in the LCA review, as per Option 3, without taking into consideration the asset condition. Option 3 would increase vehicle reliability and provide assurance of vehicle availability more so than the other two options. However, Option 3, among other things, would require more capital funding over the 2020-2024 plan period and would not be the most cost-effective solution.

The managed fleet replacement approach ensures that capital investments are made at a level and pace that minimizes asset maintenance, repair, and capital costs. An optimally timed vehicle replacement strategy also ensures that the appropriate level of vehicles are available to support system maintenance and capital investment plans. As such, Option 2 provides maximum value for ratepayers.

E8.3.6 Execution Risks & Mitigation

There are two primary execution risks inherent in the Program. The first is the fluctuating exchange rate between Canadian and American currency. Most heavy duty and specialized vehicle manufacturers are located in the United States. The weakening of the Canadian dollar in recent years increased the cost of cab and chassis for bucket trucks, line trucks and other specialized trucks, as well as lift equipment and parts. The value of the Canadian dollar has dropped since 2012. As a mitigation strategy, Toronto Hydro has secured multi-year tenders with limitations on cost increases per year (1.8 percent maximum). In addition, where possible, Canadian supplies are chosen since total costs per unit are approximately 10-15 percent less when compared to vendors based in the United States.

Vehicle lead time is another critical execution risk. Once the vehicle specifications have been drafted, and the procurement process has been completed, vendors must be awarded the bid and a purchase order must be issued with sufficient time for the vehicle to be delivered in the current plan year. While unit order size and relationship with the vendor can sometimes reduce product lead time, many variables such as the manufacturer's inventory of the requested vehicle, vendor time availability to perform up-fits/customizations, and specification complexity, are not controlled by the successful bidder. For instance, the successful bidder may only perform the up-fit portion of the delivery in-house, and may order all other parts of the unit specified in the tender from another vendor. The lead-time risk can be mitigated by awarding plan submissions well in advance of the calendar year of purchase. In order to do so, Toronto Hydro will need to ensure that vehicle reviews, specifications, and request for proposal/quotation are largely completed in the first half of the prior calendar year. Multi-year contracts for bucket truck tenders is another strategy utilized to lock in pricing of a completed unit and guarantee truck deliveries and forecasted in-servicing of new bucket trucks.

E8.4 Information Technology and Operational Technology Systems

E8.4.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 231.2	**2020-2024 Cost ($M):** 281.4
Segments: IT Hardware, IT Software, and Communication Infrastructure	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Customer Service, Public Policy, and Financial	

The Information Technology and Operational Technology[1] Systems ("IT/OT") program (the "Program") proposes to invest in hardware, software, and communication assets that provide critical support to Toronto Hydro's customer and business-facing services. Toronto Hydro relies on IT/OT systems to execute capital and operational programs, including customer-facing and operationally-critical functions. The investments proposed in this Program were developed in accordance with Toronto Hydro's IT Asset Management Strategy,[2] which mitigates risks to reliability, cybersecurity, and the utility's business operations.

The Program's objective is to provide reliable technology solutions and services to support Toronto Hydro's business functions, including effective and reliable service to customers, safe and efficient management, and operation of the distribution system, compliance with legal and regulatory requirements, and sustainment of the utility's long-term financial viability.

The Program consists of the following three segments:

- **IT Hardware**: includes the core back end infrastructure assets (e.g. servers, local area networks and data storage/centres) and endpoint assets (e.g. desktop computers, laptops, printers, smart phones, and tablets) that support Toronto Hydro's day-to-day operations and core systems;
- **IT Software**: includes software applications that provide process improvements to a range of customer-facing and business functions; and,

[1] Operational Technology refers to hardware and software that detect or cause a change through the direct monitoring and/or control of physical devices, processes, and events in the enterprise (https://www.gartner.com/it-glossary/operational-technology-ot/).
[2] Provided at Exhibit 2B, Section D5.

- **Communication Infrastructure**: includes assets that enable the monitoring and control of distribution communication infrastructure, including fibre-optic assets and wireless Supervisory Control and Data Acquisition ("SCADA") infrastructure.

E8.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Improving the customer experience of interacting with the utility through digital platform; and ○ Supporting accurate and timely communication with customers during prolonged power outages.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Maintaining the availability of modern, reliable and secure enterprise-wide IT/OT systems that support efficient distribution system management; ○ Supporting outage restoration efforts by ensuring that system operators have the necessary IT/OT tools to promptly identify incidents, develop effective resolution plans and communicate with operational teams; and ○ Enhancing IT/OT systems to enable remote equipment monitoring and operations capabilities.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Providing the technological infrastructure framework required to achieve conservation and demand management targets, enable grid-modernization, and support energy storage and distributed energy resources; and ○ Ensuring the effectiveness and availability of IT/OT systems that are required to support the utility's implementation of new policy initiatives and compliance with regulatory requirements, including those arising out of the OEB's Cyber Security Framework.

Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by: ○ Enabling the constant monitoring of substation and field assets; and ○ Maintaining the effectiveness and availability of IT/OT Systems that support the utility's safety performance (such as Intelex, Learning Management System, SCADA, Automated Vehicle Locator, Field Mobility System, Radio, and Network Management System).
Financial	• Contributes to Toronto Hydro's financial objectives by ensuring that the Tier 1 IT systems are available and reliable in support of efficient and accurate financial reporting.

E8.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Cyber Security Risks, Regulatory Compliance, and Functional Obsolescence

The Program supports Toronto Hydro's core operations and business processes, and enables the safe and efficient execution of the utility's capital and operational programs. The utility relies on its IT/OT systems to manage and operate the electricity distribution system, satisfy its obligations to customers, and comply with existing and emerging regulatory requirements.

E8.4.3.1 IT Hardware

Toronto Hydro's IT hardware must be renewed on a regular basis to ensure that systems that support customer-facing services, core distribution operations and other important processes continue to function reliably with a low risk of failure. Toronto Hydro employs many software applications to automate processes and efficiently execute required tasks such as preparing customers' bills and dispatching crews to respond to outages. These applications run on IT hardware, the building blocks of the overall IT System that must be reliable to ensure that the software applications it houses remain available.

IT hardware infrastructure assets support a number of customer service functions. Currently, approximately 224,420[3] customers use the online electronic billing function and approximately 282,000[4] customers have accounts that provide key self-serve functions, such as management of account details, customer moves, payment options, and landlord information. Hardware assets also support a number of customer interfacing applications and processes delivered via telephony through the Toronto Hydro Call Centre. If the hardware assets supporting these functions were to fail, customers would be unable to access these systems, and could experience significant delays in completing routine transactions. This would impact customer service satisfaction and likely lead to increased volume of calls and complaints to Toronto Hydro's Call Centre.

Hardware assets support systems that are used to manage field crews and respond to outages, and thus are critical to the utility's ability to meet operational outcomes, including reliability. By providing distribution grid management employees real-time access to crew availability, geographic outage location and crew location, these systems enable Toronto Hydro to efficiently and effectively deploy crews to restore power to customers in a timely fashion. In the event of core backend infrastructure failure, the functionality of these applications would be impaired, and as a result, Toronto Hydro's outage response time would be negatively affected.

IT hardware also underpins the utility's environmental, health, and safety processes across its work centres and job sites. Such processes range from completion of site conditions and safety forms, review of Material Safety Data Sheets, safety and environmental audits, and incident and claims investigations. In the event of an IT hardware or software failure, employees may not have access to the information required to make informed decisions about environmental and health and safety issues that may be serious and time-sensitive, thus potentially compromising work safety or contributing to inadvertent breaches of applicable compliance requirements.

IT hardware investments are planned and implemented with regard to both current and future utility needs and operational requirements in order to enable Toronto Hydro to execute its plans and programs securely and efficiently in pursuit of its short- and long-term objectives. IT hardware standards are regularly reviewed, assessed, and implemented based on the utility's requirements from operational, regulatory and customer service perspectives. This requires Toronto Hydro to continuously invest in its IT hardware assets.

[3] As at the end of 2017.
[4] Ibid.

IT hardware assets are classified as either Endpoint Assets or Core Backend Infrastructure Assets. Endpoint Assets are the assets that the end-user interfaces with to execute, process, complete and review business tasks and operations. These include computing assets (e.g. desktops, laptops, and tablets) that support the execution of business processes, data transactions and analysis, as well as printing assets (e.g. printers, plotters, and photocopiers) that translate electronic documents like engineering drawings and contracts onto paper. Both are relied upon extensively by Toronto Hydro's IT users to execute daily work across the utility.

Core Backend Infrastructure Assets are responsible for the computation, storage, and communication necessary to support IT systems. Servers manage access to centralized resources and services in the network and security appliances secure the network from unwanted traffic. Storage assets enable the secure retention of digital data such as customer information, and include disk and flash arrays, which store records for access by servers. Communication assets facilitate the exchange of data within and between the core backend assets and the endpoint assets, so that users can access information from a central IT system. Network and telephony assets enable computers, services, and storage devices to exchange data and manage communication services.

Figure 1 depicts the typical structure and dependency of IT hardware assets.

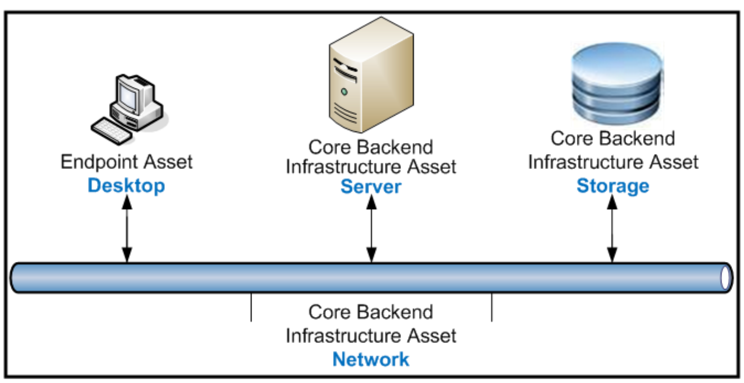


Figure 1: Typical Endpoint Asset to Core Infrastructure Relationships

Toronto Hydro currently manages its renewal of over 2,000 endpoint assets and over 1,500 core backend infrastructure assets using a structured IT Asset Management approach, which can be found in Exhibit 2B, Section D5. Toronto Hydro's IT Asset Management Strategy is aligned with industry best practices, vendor lifecycle recommendations, and Toronto Hydro empirical data.

The lifespans of hardware assets range from four to seven years, which are considered to be within industry norms. At the end of its lifecycle, hardware assets' risk of failure increases significantly, potentially impacting core business processes.

To determine the refresh cycle for existing hardware, Toronto Hydro maintains an inventory of hardware assets that includes technical details and lifecycle information such as date of implementation and end of vendor support. This approach ensures that IT hardware assets are available to support the effective and efficient execution of the utility's operations.

Adhering to this approach, approximately 90 percent of Toronto Hydro's core backend infrastructure, and 100 percent of its endpoints assets will need to be replaced during 2020 to 2024. These include data and voice network routers, switches and appliances, storage network switches, storage arrays, data backup appliances, file storage appliances, UNIX and Windows servers, security, and monitoring appliances, and uninterruptable power supplies.

E8.4.3.2 IT Software

Investment in IT software is required to:

- ensure that current applications can continue to operate reliably and with minimal risk exposure to cyber threats;
- make targeted and prudent IT enhancements to current functionality in response to core business needs or risks; and,
- respond to evolving regulatory or compliance obligations.

IT software is omnipresent in the modern utility. Toronto Hydro relies upon, and must maintain, various IT software systems to efficiently manage core operations and business processes and to execute planned programs relating to Distribution Grid Infrastructure Design and Construction, Distribution Grid Operations, Customer Billing and Service and Corporate Services.

Without these systems, a utility of Toronto Hydro's size and complexity would encounter significant challenges in operating its electricity distribution system, delivering capital programs and satisfying obligations to customers and other parties with which it interacts. Moreover, in the absence of incremental funding to build additional capabilities, the utility could be forced to bypass opportunities to improve productivity or innovate service offerings to meet customers' evolving needs and preferences.

Software applications deliver tangible value to customers directly through customer-facing IT services, and indirectly through the improved performance (or avoided risks) of business-facing platforms and solutions. To maintain a reliable and productive suite of IT Software, Toronto Hydro makes three types of investments:

- Software Upgrades
- Software Enhancements
- Regulatory Compliance

1. Software Upgrades

Over the 2020 to 2024 period, Toronto Hydro plans to upgrade all of its software applications. These upgrades will ensure that Toronto Hydro's software systems receive support from vendors, keep pace with technology changes, remain integrated with other relevant software systems, and are protected against cyber security threats.

When IT systems are beyond the period of extended vendor support, the vendor and the marketplace do not guarantee availability of qualified resources and expertise needed to resolve any potential issues. As a result, the failure of these systems may result in prolonged restoration, which can significantly affect the utility's operations and its ability to execute planned work programs and deliver service to customers.

In addition, legacy IT systems no longer receive security patches and performance upgrades or fixes, rendering the applications more vulnerable to cyber-attacks. Every month, Toronto Hydro's IT security team successfully blocks as many as 20 million internet-based attacks. These attacks attempt to tamper with normal IT system operations, gain unauthorized access to confidential information, or cause a machine or network resource to be unavailable to its intended authorized users.

A successful cyber-attack on the Customer Information System ("CIS"), for example, would compromise customer usage and billing data, including confidential customer information. Stolen customer data can be used in fraud and identity theft, as was the case in the January 2018 cyber-attack on Metrolinx by hackers.[5] This event highlights the real risk and consequences of cyber intrusions and the ongoing need for Toronto Hydro to regularly upgrade its software and hardware

[5] Toronto Star, Metrolinx Targeted by North Korean Cyber Attack (January 23, 2018), available at <https://www.thestar.com/news/gta/2018/01/23/metrolinx-targeted-by-north-korean-cyberattack.html>.

in order to protect its systems from external attacks.[6] Similarly, a leak of Toronto Hydro's sensitive operational information could lead to and assist in malicious attempts to jeopardize day-to-day operations and, in extreme cases, the successful exploitation of a system vulnerability that can cause mass outages across the grid.

The ongoing use of applications past end of useful life leads to retention and maintenance of standalone underlying components that lag vendor support lifecycles. This exposes the IT systems to security and failure risks from the underlying components.

Toronto Hydro must address these risks by upgrading its applications to maintain compatibility with underlying infrastructure.

Table 4 below sets out all major IT systems (known as "Tier 1" systems) and their underlying infrastructure that will reach their end of life in the 2020 to 2024 period and must be upgraded. Tier 1 applications support utility-wide processes, are functionally integrated with other applications, and are supported by a host of databases, middleware, storage and network devices. In a disaster scenario, Toronto Hydro requires that a Tier 1 system be recovered in four hours or less.

Table 4: Toronto Hydro's Tier 1 IT Systems

Tier 1 System Name	Expected System Age at end of 2024	System Lifecycle (in years)
Warehouse Management System	6	4 to 5
Geospatial Information System	6	4 to 5
Supervisory Control and Data Acquisition System	7	4 to 5
Distribution Network Management System	6	4 to 5
Outage Management System	6	4 to 5
Operational Data Store	5	4
Meter Management System	6	3
Customer Information System	13	5 to 7
Enterprise Resource Planning System	6[7]	5 to 10

[6] In March 2018, the United States Computer Emergency Readiness Team issued an alert on Russian government actors targeting U.S. Government entities and organizations in the energy section. See https://www.us-cert.gov/ncas/alerts/TA18-074A.

[7] The version of SAP used for Toronto Hydro's ERP was three years old at the time of implementation in 2018, and will be out of support in 2025. The lead time required to implement an ERP requires more than 12 months of active preparation

The Enterprise Resource Planning ("ERP") and CIS upgrades are the most significant upgrades based on size and complexity, and are discussed in greater detail in the Expenditure Plan. Both are fundamental to the utility's ongoing operations. Without full vendor support, any disruption caused by a system failure is likely to take longer to resolve resulting in additional costs and delays to correct the failure. For the ERP, this could disrupt Toronto Hydro's financial processes and the ability to report accurate information in line with regulatory requirements.

Toronto Hydro's CIS currently processes approximately $18 million per day in electricity costs. Billing delays due to CIS issues can give rise to major customer and financial impacts, and would put at risk Toronto Hydro's ability to meet OEB-established metric on billing accuracy. The current legacy system entails increased security risks because it no longer receive security patches from the vendor. This is an especially serious issue as security breaches can compromise confidential customer information, such as customer bank accounts and Social Insurance Numbers.

Functional obsolescence is an additional consideration driving the need to invest in software upgrades. Finding skilled resources to ensure ongoing support optimization for legacy systems is and will become more challenging. This was previously a challenge with respect to Toronto Hydro's legacy ERP System Ellipse, as outlined in Toronto Hydro's 2015 CIR application (Exhibit 2B, E8.6), and is now a particular concern for the CIS system.

Over time, Toronto Hydro customized its CIS, often in response to new regulatory requirements. Integrating such customizations into the architecture of the utility's overall IT infrastructure has become increasingly complex and time consuming. In the interim, Toronto Hydro is managing this risk by incurring additional IT operating costs and additional testing of modifications to the system. However, these costs are expected to continue escalating as customizations become more complex and costly to implement, test, and maintain.

Toronto Hydro's other Tier 1 applications also require upgrades to mitigate reliability and cybersecurity risks. Control room operators and dispatchers rely extensively on the Outage and Distribution Management System and Mobile Network Management System to access real-time outage data and to view the location and status of field crews. Upgrading these systems ensures Toronto Hydro's continued ability to respond to outages in a safe, timely, and efficient manner. In addition, system enhancements and analytics in relation to these applications can provide Toronto

with a System Integrator. The timing of the expenditure to upgrade the ERP prior to losing support therefore falls within the 2020 to 2024 period.

Hydro with critical information about managing resources and restoring power to customers in emergency events.

Engineers, designers, and field crews depend on IT systems such as the Geospatial Information System ("GIS") and the Distribution Network Analytical Tool to access important information about assets across the distribution system, and to develop asset replacement plans, determine project detail estimates and review the conditions of assets prior to physical intervention.

Toronto Hydro's construction project teams and outage response teams rely on IT solutions to execute work plans and respond to outages. The inventory management system facilitates this function by managing asset inventory levels across multiple warehouse locations, and enabling the delivery of materials at job sites and key locations across the system. A failure of this system could lead to errors in materials information that could affect asset costing information, or even worse, jeopardize the safety of employees using these materials. Delays in the delivery of materials to project sites could also hamper the utility's ability to respond to outages and execute planned work in a timely and efficient manner.

In addition, Toronto Hydro is proposing to upgrade its suite of Tier 2 IT software applications, which support targeted processes and have little or no integration with other enterprise applications. Compared to Tier 1 applications, Tier 2 applications generally have lower maintenance costs and support a smaller user base. As such, both the risks and corresponding investment costs associated with Tier 2 software upgrades are lower. Examples of such applications are the data analytics software application, power quality application, and the fuel data system. Lifecycles developed in accordance with Toronto Hydro's IT Asset Management Strategy are five years or less for these applications. Accordingly, all Tier 2 systems will require one or more upgrades during the 2020 to 2024 period.

2. Software Enhancements

Over the 2020 to 2024 period, Toronto Hydro plans to undertake software enhancement projects in alignment with its IT Asset Management Strategy, located at Exhibit 2B, Section D5. Whereas software upgrades are typically triggered by emerging reliability or cybersecurity risks, software enhancements are driven by risks to a particular customer-facing or business process. A specific type of risk driven by compliance requirements is discussed more thoroughly in the following section.

Toronto Hydro expects increasing demands to continue from customers and internal clients. External facing enhancements, such as initiatives related to the web portal and customer billing, aim to ensure customers can access information and interact with Toronto Hydro securely and efficiently, such as by expanding payment options to include credit card processing. Data analytics expansions could enable the development of descriptive and predictive analysis data models to assist in areas such as long-term strategy and planning, generation and capacity planning, asset maintenance planning, outage prediction, system planning, and power quality and reliability planning.

Just as software enhancements address a range of emerging business risks, they can be implemented using a variety of different IT approaches. Previously independent systems can be integrated to mitigate the risk of data errors stemming from manual work-around processes. Incremental reporting capability can be built to fills gaps in management processes and decision making. Adding functionality or new software tools can add capabilities that meet emerging customer needs and preferences or mitigate cost pressures.

Toronto Hydro employs a rigorous and comprehensive methodology, as described in the IT Asset Management Strategy (Exhibit 2B, Section D5). Projects undergo a stringent review process and are operationalized through a strictly governed implementation process, summarized below.

- **Evaluate**: The utility validates the proposed initiative and works with the relevant business unit(s) to determine the project scope, business requirements, current state business processes, future state business processes, the options to achieve the future state, and the preferred approach, costs, and benefits.
- **Align**: Toronto Hydro reviews the proposed project to help ensure the following:
    - Governance, due-diligence, rationale, and accuracy of the project costs and benefits;
    - Strategic alignment with Toronto Hydro’s objectives (e.g. value for money);
    - Alignment with Toronto Hydro’s risk profile (e.g. cyber security); and
    - Alignment with existing technology investments and standards.
- **Prioritize**: Toronto Hydro prioritizes the project based on a combination of factors, including project dependencies, costs, benefits, strategic alignment, and risk assessment.
- **Execute**: Project execution typically consists of the following steps:
    - Gathering more detailed user and technical requirements;
    - Mapping the relevant business processes;
    - Developing and/or procuring the application as needed;

- Provisioning the infrastructure to host the application;
- Configuring the application to meet business requirements;
- Testing the application for compatibility with Toronto Hydro's infrastructure;
- Engaging users to test that the application meets their business and functional requirements;
- Training users on the features and functionality of the application; and
- Implementing the application across the appropriate departments.

3. Regulatory Compliance

Each year, Toronto Hydro must make changes to its business processes in order to comply with emerging regulatory requirements and be responsive to public policy priorities. Among the many drivers of new policy, requirements are accessibility obligations and requirements of Measurement Canada, the OEB, the IESO, the Ontario Securities Commission, and the Ministry of Labour. Failing to meet regulatory compliance obligations exposes Toronto Hydro to financial risk, in the form of penalties, and reputational harm.

In 2015 to 2017, Toronto Hydro implemented a number of software changes to respond to evolving regulatory compliance matters, including the cessation of the Ontario Clean Energy Benefit, the implementation of the Ontario Electricity Savings Program and the Ontario Rebate for Electricity Consumers, and the move to monthly billing. For more on monthly billing, please see Exhibit 9, Tab 1, Schedule 1.

Toronto Hydro anticipates this policy-driven investment to continue in the 2020 to 2024 period. To minimize risk and optimize benefits realization, Toronto Hydro follows the same four-step "Evaluate-Align-Prioritize-Execute" process used to govern the development of Software Enhancements.

E8.4.3.3 Communication Infrastructure

Toronto Hydro has four discrete communication infrastructure needs in the 2020 to 2024 period. Communications infrastructure is relied upon by core utility operations to maintain and operate the distribution system in a safe and reliable manner. The proposed investments address functional obsolescence in Toronto Hydro's current communications infrastructure footprint, address safety and reliability risks, and support the monitoring and control of future smart grid technologies.

Over the 2020-2024 period, Toronto plans to undertake the following types of work in this segment:

- Distribution system communication technology upgrade;
- Distribution system fibre-optic plant replacement and expansion;
- Wireless SCADA infrastructure upgrade; and
- Underground radio expansion.

1. Communication Technology Upgrade: SONET migration and decommissioning

Toronto Hydro relies on SONET communication technology at substations on the 13.8 kV system for SCADA communication to operate remote terminal units ("RTU"), which provide automated control of station assets such as circuit breakers. SONET is a legacy communication technology, developed in the 1980s. It is no longer supported by the manufacturer and has limited capacity to support increased automation at additional substations. If not replaced, SONET would become more expensive to maintain and limit Toronto Hydro's ability to leverage communications-based innovations to improve performance. The modern replacement for SONET is the routed IP network, supported by Multi-Protocol Label Switching ("MPLS") technology.

2. Fibre-Optic Plant Replacement and Expansion

Currently, approximately 300 kilometres of fibre-optic cable connect various in-field communication technologies to Toronto Hydro's Control Centre. For example, SCADA equipment that can be remotely operated from the Control Centre relies on fibre-optic cable to convey instructions. During 2015 to 2019, Toronto Hydro deployed approximately 70 kilometres of fibre-optic cable to remediate reliability concerns with the current plant and to expand SCADA capabilities to more locations. Toronto Hydro needs to install approximately 10 kilometres of additional fibre-optic cable to target areas of fibre, that are failing more frequently.

3. Wireless SCADA Infrastructure Upgrade

Wireless SCADA infrastructure is required to enable SCADA monitoring and control functionality for field assets where it is more cost effective than fibre-optic plant, such as smaller municipal station RTUs and pole-top distribution grid assets. Wireless SCADA infrastructure is a critical service responsible for monitoring and control of distribution grid assets, and failure to maintain adequately supported telecommunications infrastructure in this space could negatively impact service restoration times, crew safety and operational efficiency.

In 2015, Toronto Hydro operated five different legacy wireless SCADA technologies, which it proposed to address as part of the 2015 to 2019 Distribution System Communication Infrastructure ("DSCI") Program (see 2015 CIR Application, Exhibit 2B, E6.22). During the course of the upgrade, the underlying GE SD9 technology reached end of life and became functionally obsolete, meaning that it would no longer be vendor-supported and thus be prone to longer outages that impede restoration efforts. Toronto Hydro plans to replace GE SD9 with GE Orbit, the current technology that is supported by the vendor.

4. Underground Radio Expansion

This initiative is intended to address gaps in Toronto Hydro's radio coverage at certain underground vaults that are located well below ground level (i.e. parking level 2, "P2", or lower). Based on operational experience, current radio technology has connectivity challenges at specific locations, which create safety and operational concerns. To mitigate these risks, Toronto Hydro intends to procure and deploy powered wall-mounted units with wireless Bluetooth microphones, which pair to standard radio units so they can be used in locations where they otherwise could not receive a signal.

E8.4.4 Expenditure Plan

Table 5: Historical & Forecast Program Costs ($ Millions)

Segments	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
IT Hardware	7.5	9.3	10.1	7.8	7.8	11.5	10.3	11.6	14.0	14.5
IT Software	14.8	21.7	40.3	50.8	19.7	41.0	43.0	35.8	40.5	48.2
Communication Infrastructure	6.1	17.6	4.9	6.0	6.9	2.2	2.4	2.1	2.1	2.1
Total	**28.4**	**48.6**	**55.4**	**64.6**	**34.4**	**54.8**	**55.7**	**49.5**	**56.6**	**64.8**

Over the 2020 to 2024 period, Toronto Hydro forecasts spending $281.4 million across the three IT/OT Program segments. This represents an increase of $50.2 million (or approximately 22 percent) compared to 2015 to 2019 spending, which is inclusive of the following programs from Toronto Hydro's 2015 Distribution System Plan:

- E8.4 (IT Hardware)
- E8.5 (IT Software)

- E8.6 (Enterprise Resource Planning Program)
- E8.7 (Voice Radio System Upgrade Program)
- E6.22 (Distribution System Communication Infrastructure)

In addition, capital expenditures discussed in the Monthly Billing DVA in this application (see Exhibit 9, Tab 1, Schedule 1) map to the IT software segment.

IT/OT systems perform vital functions that are central to the safe and reliable operation of the distribution system and effective interaction between the utility and customers. The level of proposed spending is required to (i) refresh IT hardware systems at the end of their useful life, including data centre assets that were last upgraded just prior to the 2015 to 2019 period; (ii) upgrade Toronto Hydro's IT software applications that require remediation during the period, including the ERP and CIS, and make targeted investments to provide software enhancements that address business risks or compliance matters; and (iii) address specific OT system needs to mitigate risks such as functional obsolescence.

A number of controls and practices are in place to ensure that IT expenditures are prudently incurred and deliver value to customers either directly, through improved customer service, or indirectly from the performance or cost improvements enabled by certain investments. IT/OT expenditures are subject to Toronto Hydro's procurement policy, which can be found in Exhibit 4A, Tab 3, Schedule 1. For IT software investment, this applies to both the application itself and the system integration support services that are required to implement the solution efficiently and cost-effectively. Where feasible, Toronto Hydro makes efforts to time the procurement process during periods of the year when it is more likely to obtain discounts, such as year-end. Toronto Hydro also seeks to leverage existing vendors of record lists at the municipal or provincial level in order to leverage any potential volume discount that would allow the utility to obtain IT products at lower price points.

An independent benchmarking study performed by Gartner Consulting (see Appendix A) concluded that Toronto Hydro's total IT expenditures per user in both 2017 and 2020 benchmark competitively against industry peers.[8] Gartner also concluded that in both years that the distribution of Toronto Hydro's IT investments "by cost category, investment category and functional area are all comparable to the peer group, with some variation but no significant issues identified."[9]

[8] Gartner Consulting (2018), *IT Budget Assessment Final Report* found in Exhibit 2B, Section E8.4, Appendix A. pg. 1.
[9] Ibid.

Gartner further assesses Toronto Hydro's spending in a Run-Grow-Transform paradigm,[10] defined as:

- **Run**: "an indicator of how much of the IT resource is consumed and focused on the continuing operation of the business."
- **Grow**: "an indicator of how much of the IT resource is consumed and focused on developing and enhancing IT systems in support of business growth (typically organic growth) or improvement."
- **Transform**: "an indicator of how much of the IT resource is consumed and focused on implementing technology systems that enable the enterprise to enact new business models."

In both 2017 and 2020, Toronto Hydro IT investments are primarily directed at maintaining current business capabilities ("run") with the remainder directed at expanding existing business capabilities or driving new ones ("grow" and "transform" respectively).[11] The resulting split among the three categories is comparable to the peer group average, with slightly more focus on the "run" category. Toronto Hydro interprets this result as confirmation that its IT expenditures are appropriately balanced.

E8.4.4.1 IT Hardware

The table below outlines the approximate volume of hardware assets that Toronto Hydro plans to upgrade or replace during the 2020-2024 plan period.

Table 6: Hardware Volumes

Asset Category	IT Hardware	2015-2019 Actuals/Bridge		2020-2024 Plan	
		Capacity /Units	Total Cost ($M)	Capacity/ Units	Total Cost ($M)
Core Backend Infrastructure Assets (Capacity)	*Unix Virtual Servers*	440	33.4	560	50.8
	Linux x86 Virtual Servers	250		350	
	Windows Virtual Servers	1460		2660	
Endpoint Assets (Units)	*Personal Computing Devices*	2310	9.1	2310	11.1
	Printers & Plotters	180		180	

[10] Ibid, pg. 6
[11] Ibid, pg. 16

IT hardware cost estimates are derived by forecasting the number of hardware assets that are past their useful life and that are needed for incremental needs over the 2020 to 2024 period.

Toronto Hydro's IT Asset Management Strategy (Exhibit 2B, Section D5) details the utility's approach to replacing IT hardware assets. The timing and pacing of investment in each asset sub-type is driven by the asset lifecycle defined in the applicable standard, which are based on factors such as the criticality of the infrastructure, industry best practice, and vendor specifications. These standards are designed to extract the maximum value from hardware assets and minimize the negative impact of potential asset failures.

Toronto Hydro also considers forecast capacity requirements to ensure it has the necessary IT hardware to support general business growth and associated increased data storage and data processing requirements. The forecasts are based on the analysis of the following factors:

- Historical trends of current assets capacity versus utilization by existing IT systems;
- Asset resource requirements to support system enhancements and new initiatives; and
- New operational requirements that necessitate increased hardware resources.

Based on this approach, Toronto Hydro will require $61.9 million to replace its IT hardware with upgraded assets. Of Toronto Hydro's current assets, approximately 90 percent of existing core backend infrastructure (e.g. network, storage, and server assets) are forecast to require replacement in order to address reliability risks associated with those assets and provide the incremental capacity needed to support Toronto Hydro's IT footprint. The utility anticipates that all endpoint assets will need to be replaced between 2020 and 2024, at a pace that will address an approximately equal number of assets each year.

The main drivers of variance in spending are attributable to the timing of the asset lifecycles within the 2020 to 2024 period. During 2015 to 2019, only 50 percent of Toronto Hydro's core backend infrastructure assets needed to be replaced, whereas this is expected to rise to 90 percent during 2020 to 2024. The largest contributing factor is Toronto Hydro's two data centres, which were last renewed in 2014 and are scheduled for replacement during the next rate period. This scheduled refresh accounts for a majority (approximately $12 million) of the variance in spending between the two periods.

E8.4.4.2 IT Software

1. Software Upgrades

Over the 2020 to 2024 period, Toronto Hydro plans to spend $208.5 million on IT software upgrades, enhancements and regulatory compliance initiatives.

As discussed in the driver's section, Toronto Hydro plans to upgrade its Tier 1 software applications. Table 7, below, outlines the historical and forecast spending for the Tier 1 software applications.

Table 7: Tier 1 IT Systems Upgrades Costs ($ Millions)

IT Systems	2015 - 2019 Actual & Bridge	2020 - 2024 Plan
ERP	62.8	46.3
CIS	10.0	38.5
Tier 1 Systems excluding CIS & ERP	**36.7**	**40.2**
Tier 1 Systems Total	**109.5**	**125.0**

a. Enterprise Resource Planning

Compared to the 2015 to 2019 period, Toronto Hydro is proposing to decrease its spend in relation to the ERP system. As discussed in the 2015-2019 DSP (Exhibit 2B, E8.6), the utility detailed its need to replace the legacy system, Ellipse, in favour of a modern application to address significant reliability and cybersecurity risks. Through a competitive process, Toronto Hydro procured an independent System Integrator services provider for SAP implementation. In addition, the approved ERP program entailed the consolidation of 30 other legacy systems into the new ERP to streamline the effort required to administer and support those functions over the long run and minimize business risks.

In the 2020 to 2024 period, the scope of Toronto Hydro's planned investment in its ERP is reduced and paced more consistently across the five years. Toronto Hydro plans to upgrade its ERP database and application, referred to as ECC, to the current version of SAP's system, referred to as HANA. This upgrade is required because SAP will no longer provide vendor support to the ECC version by 2025. Without the proposed upgrade, this core IT system would be exposed to unacceptable reliability and cybersecurity risks, as detailed in Section E8.4.3. In addition to this upgrade, Toronto Hydro expects to implement ongoing security patches while vendor support is still available and incur data archiving and decommissioning costs from previous legacy programs.

The most opportune time to upgrade to HANA is expected to be later in the 2020 to 2024 window. By that time, SAP is more likely to have developed patches to address defects and performance issues that decrease system reliability and increase integration costs for early adopters. A more complex upgrade to HANA that would include more real-time analytics and logistics, and other required upgrades, was considered as part of the options analysis but ultimately determined to be sub-optimal. Please see the next section for a more detailed discussion.

In addition to the upgrade to the HANA platform, Toronto Hydro is proposing to make incremental improvements to the capability of its ERP system. These enhancements would build functionality within the ERP to address business risks (i.e. by minimizing manual processes or standalone systems) and/or mitigate cost pressures. Twelve different enhancements are proposed for the 2020 to 2024 period, addressing core processes such as regulatory compliance, timekeeping, health and safety functionality, and asset analytics.

Over the 2020 to 2024 period, Toronto Hydro also plans to integrate the ERP with other core IT systems. Integration enhancements would allow for the seamless exchange of information between systems, helping to mitigate the risks inherent to manual efforts that are otherwise necessary, or to improve reporting capabilities to assist decision making. The four applications planned for integration are the Document Management System, Customer Care & Billing (CIS), NMS/Oracle MWP, and GIS.

Toronto Hydro is proposing to stagger these investments over the course of the rate period in order to generate incremental benefits for IT operations. Sequencing the expenditures in this way will increase the likelihood that experience gained from the current ERP implementation during 2015 to 2019 could be leveraged to reduce the scope and cost of future System Integration services for ERP-related activities. In addition, pacing investment in the ERP helps to reduce the likelihood that more lumpy investments will be necessary in the future, such as what was required to replace Toronto Hydro's legacy ERP, Ellipse.

b. <u>Customer Information System</u>

Since April 2016, Toronto Hydro's legacy CIS has been without vendor support from Oracle, leaving it exposed to reliability and cybersecurity risks, as detailed above in Section E8.4.3. CIS is the foundation of a range of customer service functions, and any disruptions would likely have significant implications for the utility's customers. It is a highly connected application (33 major integration points with other systems), the result of emerging compliance-related, and business or customer-driven adaptations.

To maintain the current CIS after the expiration of vendor support, Toronto Hydro invested in customizations (e.g. the provision of self-service options through *mytorontohydro.com*) that are increasingly difficult to administer and maintain. At present, there are about 1,000 separate interfaces, configurations, and customizations to the original Customer Care & Billing product, which can impede the ability to integrate the CIS with other systems, and thus limit their ability to improve business processes.

Toronto Hydro plans to upgrade to a fully supported version of Oracle's CIS, including the application, integration, reporting, middleware, and database. New "out of the box", functionalities are more technically capable to meet modern billing demands. Maintaining an Oracle-based solution (common among LDCs in Ontario) would allow Toronto Hydro to work collaboratively with its peers to find solutions to new compliance-related requirements. Functions that are currently carried out by customized code developed to provide functionality in relation to compliance requirements or other similar drivers will be embedded within the new system. This will make it easier and more cost-effective to adapt to new customer service or billing-related requirements, such as those related to the Long Term Energy Plan or Implementation Plans. The planned upgrade to the CIS would be optimized by using a two-phase process, with "go-live" dates currently scheduled for 2021 and 2024 respectively. This reduces implementation risks, optimizes the use of IT resources, and maintains vendor support for performance and security upgrades.

The upgraded CIS is expected to deliver considerably more flexibility to execute highly specific operations that will improve customers' experience (including with the Call Centre, billing, customer connections, and other customer-facing services) or reduce their transaction costs.

c. Other Tier 1 Systems

During the 2020 to 2024 period, Toronto Hydro plans to upgrade its other Tier 1 applications (listed above in Section E8.4.3) in line with lifecycles developed pursuant to its IT Asset Management Strategy. Cost variances for these upgrades, as shown in Table 7, are primarily due to inflation.

d. Tier 2 Systems

Table 8: Planned Tier 2 Application Upgrades

	2015-2019 Actuals/Bridge		2020-2024 Plan	
	Number of Applications	Cost ($M)	Number of Applications	Cost ($M)
Tier 2 Systems	61	8.0	72	13.4

The forecasts in the table above were derived by analyzing the lifecycles of all Tier 2 applications. Applications must be upgraded before reaching the end of their useful lives to mitigate the risk of failure and disruption to the processes they support. Increasingly, vendors are reducing the lifecycles of Tier 2 applications, meaning an increasing number will require more than one upgrade over the 2020 to 2024 period. The increased cost of upgrading on shorter intervals, the additional number of Tier 2 Systems anticipated to be in use and general price inflation are the primary drivers of the variance between the two rate periods.

2. Software Enhancements

Whereas software upgrades are triggered by a need to address reliability or cybersecurity risks, software enhancements mitigate core business risks that would not be technically feasible or cost-effective to address through a non-IT solution. The table below presents the number of planned software enhancements initiatives and their associated costs in the 2020 to 2024 period. The table also presents the number of enhancement initiatives that are expected to be completed over the 2015 to 2019 period and their associated costs.

Table 9: Software Enhancements Volumes and Cost

	2015-2019 Actuals/Bridge		2020-2024 Plan	
	Number of Enhancements	Cost ($M)	Number of Enhancements	Cost ($M)
Software Enhancements	26	22.0	45	60.9

As discussed in the Drivers section, software enhancements can take a number of different forms: adding an additional function to an existing Tier 1 application (aside from ERP and CIS, which are discussed above); integrating two systems to leverage otherwise independent data sets;

enhancement of reporting capabilities to make better use of existing data; or adding a new application.

The increase in cost for enhancements between 2015-2019 and 2020-2024 is a result of multiple factors. In 2015-2019, significant resources were dedicated to implementing the new ERP system, which represented a significant improvement over the legacy Ellipse system. A number of enhancements were included within the scope of that project that would have otherwise contributed to spending in this category during the period. Additionally, Toronto Hydro expects that customer and operationally-driven enhancements will be necessary to address risks or respond to changing consumer preferences. Inflation also contributes to the increase in Toronto Hydro's proposed planned expenditures.

A reduction in funding for software enhancements would leave Toronto Hydro behind its peer group, and less capable of responding to emerging customer and business-driven risks. The $60.9 million in software enhancements planned for the 2020-2024 plan period accounts for approximately 30 percent of Toronto Hydro's IT software segment. Toronto Hydro's total IT expenditures, of which Software Enhancements is one component, are generally consistent with its peer group in terms of the Run-Grow-Transform paradigm articulated in the Gartner IT benchmarking study (as discussed at the outset of this section).

3. Regulatory Compliance

The table below presents the anticipated number of regulatory compliance initiatives Toronto Hydro will need to complete in the 2020-2024 period and the associated budget. Also included in the table are the number of regulatory compliance initiatives that will be completed over the 2015-2019 plan period with their associated cost.

Table 10: Regulatory Compliance Volumes and Cost

	2015-2019 Actuals/Bridge		2020-2024 Planned	
	Number of Initiatives	Cost ($M)	Anticipated Number of Initiatives	Cost ($M)
Regulatory Compliance	5	7.8	6	9.3

Toronto Hydro anticipates it will require a small increment in funding for new compliance-related initiatives in the 2020 to 2024 period, in relation to a range of public policy initiatives such as those listed in the provincial Long-Term Energy Plan, the LTEP Implementation Plans, and other important matters (e.g. cybersecurity).

E8.4.4.3 Communication Infrastructure

As detailed in Section E8.4.3, over the 2020-2024 period Toronto plans to undertake work in four discrete projects in this segment:

- Distribution system communication technology upgrade;
- Distribution system fibre-optic plant replacement and expansion;
- Wireless SCADA Infrastructure; and
- Underground radio expansion.

1. Distribution System Communication Technology Upgrade

The table below outlines the expected volume of work and associated costs over the 2020-2024 plan period to upgrade Toronto Hydro's distribution system communication technology.

Table 11: Distribution System Communication Technology Upgrade Volumes and Cost

	2020-2024 Volume (# of SONET Sites)	Total Cost ($M)
SONET Migration and Decommissioning	45	2.8

By the end of 2024, Toronto Hydro expects to eliminate the entire legacy SONET footprint and to convert all of its IT/OT station assets (e.g. RTUs) to the IP Stations Network. To achieve this plan, Toronto Hydro expects to spend approximately $0.6 million per year to engineer and execute the migration from SONET and to decommission the SONET environment. The availability of the modern IP Stations Network, delivered as part of the DSCI Program (see Toronto Hydro's 2015 CIR, Exhibit 2B, E6.22), is expected to be leveraged to carry out the planned migration and decommissioning work.

2. Distribution System Fibre-Optic Plant Replacement and Expansion

The table below outlines the expected volumes of work and associated costs over the 2020-2024 plan period to replace and expand distribution system fibre-optic plant.

Table 12: Distribution System Fibre-Optic Plant Expansion Volumes and Cost

	2020-2024 Volume (km of cable)	Total Cost ($M)
Fibre-Optic Cable	10	1.1

With the majority of fibre-optic installation completed between 2015 and 2019, Toronto Hydro expects to spend approximately $1.1 million in 2020-2024 on fibre-optic plant replacement and expansion to install approximately 2 kilometres of fibre per year. Historically, Toronto Hydro incurred costs of approximately $90,000 per kilometre, which is consistent with 2020 to 2024 forecasts after accounting for inflation.

3. Wireless SCADA Infrastructure Upgrade

The table below outlines the expected volumes of work and associated costs over the 2020-2024 period to upgrade the wireless SCADA infrastructure.

Table 13: Wireless SCADA Infrastructure Upgrade Volumes and Cost

	2020-2024 Volume (# of Radio Sites/ Endpoints)	Total Cost ($M)
SCADA High-Site Capacity Upgrade	12	0.8
Wireless SCADA Endpoint Radio Migration	885	3.0
Radio Installation	46	0.4

Toronto Hydro expects that by the end of 2024, all remaining end-of-life wireless SCADA assets will be upgraded or replaced. This work will be paced uniformly from year to year over the 2020-2024 period, taking into account the available resource capacity to perform the required tasks.

4. Underground Radio Expansion

The table below outlines the expected volumes of work and associated costs over 2020 to 2024 to expand the radio network to reach underground vaults.

Table 44: Underground Radio Expansion Volumes and Cost

	2020-2024 Volume (# of Radio Sites)	Total Cost ($M)
Underground Radio Sites	42	2.8

Toronto Hydro estimates that 42 underground vaults will require underground radio technology. This represents the number of vaults that are located underground at or below the P2 level. Each location requires radio equipment and associated installation costs, which includes drilling conduit through concrete to connect the radio equipment to an above-grade antenna.

E8.4.4.4 Project Prioritization

As detailed in the IT Asset Management Strategy (see Exhibit 2B, Section D5), Toronto Hydro has a robust decision making process to govern its IT/OT program. In accordance with this strategy, the utility ranks and prioritizes candidate initiatives in this program by weighing and balancing the following considerations and their impact on the utility's operations and customers:

- Compliance with applicable regulatory requirements;
- Required availability of the IT/OT systems to support core business operations and planned work programs. As described above, enterprise software applications are categorized into two tiers based on their criticality. Upgrades to Tier 1 applications take priority over Tier 2;
- Ensuring data in the IT/OT systems are secure and protected from cyber-attacks;
- Sustaining and improving current levels of customer service; and
- Other considerations such as application complexity, resource balancing, and co-ordination with other programs.

E8.4.5 Options Analysis/Business Case Evaluation ("BCE")

E8.4.5.1 Options Analysis/BCE for IT Hardware Segment

1. Option 1: Do Nothing

Under this option, IT hardware assets (both core backend infrastructure and endpoint assets) will be run to failure and replaced on a reactive basis. This option would introduce substantial risks to business continuity, information security, and service quality of Toronto Hydro's customer-facing and business-focused applications. Any disruptions or breaches of hardware assets would directly impact

IT software and by extension business processes reliant on the software, including critical grid services (e.g. SCADA) and customer-facing channels (e.g. Contact Centre).

Hardware beyond its useful life is more prone to failures without warning, potentially resulting in prolonged service outages and significant impact on business continuity. Old hardware is less likely to be supported by the vendor, extending the length of an outage and increasing the cost of restoration. Unsupported hardware failures may result in data losses and inability to recover lost data, posing an unacceptable risk to Toronto Hydro's ability to provide its core services to ratepayers and comply with legislative and regulatory obligations. Unsupported hardware is also more prone to cybersecurity breaches, as vendors stop issuing security patches to mitigate critical gaps once hardware becomes unsupported.

2. Option 2: Externally Hosted Solution for Core Backend Infrastructure Assets; Endpoint Asset Replacements Based on IT Asset Management Strategy

Under this option, the entirety or a portion of Toronto Hydro's core infrastructure assets would be migrated to a managed services provider, such as a data centre co-location facility or a public cloud. Toronto Hydro is concerned that externally hosted services would introduce too much risk and uncertainty at this time. Public cloud facilities are primarily tailored to corporate users operating generic web-centric applications using commodity hardware. Critical production applications, such as SCADA, NMS, and CIS, are not readily deployed through public cloud infrastructure, due to the lack of support by external providers for these types of technologies. The need for tight functional coupling between in-house infrastructure hardware, telecommunications, and in-field O/T facilities further limits the feasibility of hosting core infrastructure hardware assets externally. Cyber security is also a critical factor with externally managed infrastructure, as secure links, interfaces, and perimeter would otherwise need to be established and maintained between internal and external facilities, at significant cost.

3. Option 3: Internally Hosted Solution for Core Backend Infrastructure Assets; Endpoint Asset Replacements Based on IT Asset Management Strategy

This option would continue the status quo approach. Adherence to the established architectural standards, capacity, and lifecycle models based on industry norms will ensure a supported, scalable, available, and secure IT hardware asset base, capable of adequately supporting core business applications and processes. Operating a vendor-supported hardware base minimizes the risks to business continuity, enabling Toronto Hydro to focus on its core business functions and provide the levels of service expected by ratepayers.

This option leverages the existing investment in data centres and telecommunications facilities (e.g. fibre-optic plant) and provides purpose built IT/OT ecosystem tailored to the specific business functions provided by Toronto Hydro.

4. Option Evaluation

Option 3 is preferred. With respect to core backend infrastructure, Option 3 entails the least risk and disruption to business operations. This approach provides flexibility to modify hardware asset maintenance windows on an as-needed basis and to quickly respond to hardware outages (i.e. internally escalate hardware asset issues for resolution). Option 3 obviates the need of a secure connection between Toronto Hydro's network and externally hosted infrastructure, thus mitigating cyber security risks and avoiding incremental network connectivity costs. Option 3 also mitigates the data residency risk associated with Option 2, where Toronto Hydro would be restricted to selecting an externally hosted and managed solution within the province/country.

With respect to endpoint assets, Option 3 (which is equivalent to Option 2 for purposes of endpoint assets) is preferable because it would allow proactive replacements before asset performance deteriorates or fails. This would mitigate the risk of employee downtime, as well as re-work and data loss from failure of endpoint assets. With access to reliable and updated endpoint assets, employees will be able to perform their duties more efficiently and ultimately ensure the effective delivery of customer service and experience. Lastly, this option would also reduce the need to procure new endpoint assets on an expedited basis from vendors, or to maintain a large number of spare devices to address potential failure.

E8.4.5.2 Options Analysis/BCE for IT Software

1. Option 1: Do nothing

Under this option, Toronto Hydro would not upgrade its Tier 1 and Tier 2 applications (including the ERP and CIS), allowing them to operate without vendor support on an ongoing basis. Toronto Hydro would be responsible for maintaining and further customizing applications using manual work-arounds, which become increasingly complex, risky, and costly over time. Without vendor support for security-related patches, this option poses significant cyber security risk because outdated systems would be more vulnerable to cyber-attacks and compromises.

With respect to the ERP, the do nothing option would mean that it would become a legacy system in Toronto Hydro's IT landscape and lose vendor support by the end of the rate period. The ERP and underlying technology would no longer receive patches to fix new security or functional defects, leaving it exposed to cyber threats. The processes proposed to be integrated with the ERP would remain manual work-arounds, leaving data in silos across the organization, increasing the risk of data errors and limiting the reporting capability of the systems. Other Tier 1 systems would not be integrated, creating a barrier to more efficient and effective management of Toronto Hydro's distribution system.

With respect to the CIS, which is already without vendor support, the do nothing option would mean that the system would not gain vendor support, including patches to fix new security or functional defects. This option would also fail to integrate new process customizations, such as those relating to recent public policy changes. Continued reliance on the current CIS would significantly impede the company's ability to modify the CIS in response to future changes in public policy, customer service expectations, and industry best practices.

2. Option 2: Software Upgrades - Outsourced Management of IT Applications

Under this option, Toronto Hydro would engage a third-party service provider to manage its IT applications, including with respect to the pursuit of any required software upgrades.

This option presents a number of operational and cost risks. If significant volumes of IT-related incidents require support (e.g. due to major events like storms or flooding), third parties may not be sufficiently responsive or capable to deal with extraordinary circumstances that require intensive effort. This would also leave Toronto Hydro more exposed to vendor-related cybersecurity risks due to the change in responsibilities and direct controls over Toronto Hydro's data. This option could result in prolonged outages to the distribution system or to customer services.

Procuring contracts of this nature would exert significant cost pressures on Toronto Hydro's operational budget.

3. Option 3: Software Upgrades and Expansions Based on IT Asset Management Strategy; Simple Scope Enhancement of the ERP; and Technical upgrade of the CIS

Under option 3, Toronto Hydro would pursue standards-based asset lifecycle management of software upgrades and enhancements to meet business needs in alignment with its IT Asset Management Strategy. This option would proceed with the software upgrades to Tier 1 and Tier 2 applications. With respect to the ERP and CIS, Option 3 would entail a relatively limited level of investments, as explained below.

The simple scope enhancement of the ERP would consist of a limited one-way integration with other systems and less-capable enhancements than those proposed in the Expenditure Plan. While some benefits can be realized under this option at slightly less than 60 percent of the cost of the preferred plan, there would be minimal integration achieved with other non-ERP IT systems, and little to no new ERP functionalities (including new reporting features). Under this option, most manual work and duplicate processes will remain unchanged, and most data will be scattered across different repositories without interface with the ERP.

A technical upgrade of the CIS would provide a system that is vendor supported, and allow Toronto Hydro to adapt more easily to evolving regulatory or business requirements. Vendor support will more readily enable modifications and enhancements to the CIS in response to evolving market trends, public policy requirements, and security risks. However, customizations already built to address recent modifications would not be integrated into the software. As evolving business needs drive further changes within the new system, higher costs will be incurred under Option 3 due to the legacy process and architecture complexity and, at some point, may be technically infeasible to support. This investment is expected to cost approximately half of the proposed $38.5 million.

4. Option 4: Software Upgrades and Expansions Based on IT Asset Management Strategy; Moderate Scope Enhancement of the ERP; and Enhanced Implementation of the CIS

The main difference between Option 3 and Option 4 is the incrementally expanded, moderate scope of investments proposed for the ERP and CIS under Option 4. This option is described at length in the Expenditure Plan.

5. Option 5: Software Upgrades and Expansions Based on IT Asset Management Strategy; Complex Scope Enhancement of the ERP; and New Implementation of the CIS

The main difference between Option 4 and Option 5 is the incrementally expanded, large scope of investments proposed for the ERP and CIS under Option 5.

A complex scope solution with respect to the ERP entails a broader integration with the non-ERP IT systems and the full extent of the enhancements proposed in Option 4. It would also entail implementing a newer version of HANA that is current at the outset of its product life. This approach would yield new ERP functionalities, including many new reporting features, but is expected to cost more than double the $46.3 million proposed for Option 4.

A new implementation of the CIS entails decommissioning the current CIS and implementing an entirely new system to be selected, at a cost of approximately 30 percent more than Option 4. It would also likely require a lengthier implementation timeline to sufficiently architect the data flows and interface. Implementing a new Tier 1 system is not expected to deliver any material incremental benefits to an upgraded Oracle CIS application.

6. Option Evaluation

Option 4 is the preferred option. Compared to Options 1 and 2, this approach minimizes risks to the reliability and cybersecurity of Toronto Hydro's IT software applications. In very limited and targeted circumstances, Option 2 (externally hosted solution) would be considered for a particular software solution if it can be implemented more quickly, reduce operational risk, simplify any required change management processes, and have sufficient cyber security protections in place.

Option 3 does address the cybersecurity concerns of continuing to operate applications without vendor support, such as security patches. However, it leaves legacy customizations to the CIS unaddressed, creating operation cost and logistics challenges (which can be mitigated by Option 4). For the ERP, integration with the four systems listed in the Expenditure Plan would be limited to a single direction, significantly constraining the potential value of integration, and enhancements would not sufficiently streamline work processes in response to business needs, regulatory requirements, or customer expectations.

Option 5 would require a significant amount of additional funding for the ERP and CIS without sufficient incremental benefits. The benefits of the ERP approach in this Option would be significant, but not significantly so. There is little incremental benefit to the Option 5 approach for the CIS. On this basis, Option 5 is not preferred.

E8.4.5.3 Options/BCE for Communication Infrastructure

Toronto Hydro evaluated the following options:

- Option 1: Do nothing.
- Option 2 (Selected Option): Implement the proposed approach.

For the SONET migration and decommissioning and the wireless SCADA infrastructure upgrade, the do nothing option would leave in place the current obsolete technology. While this would temporarily defer replacement, Toronto Hydro would likely incur additional costs to maintain these assets in the absence of vendor support and/or experience longer system outages. Option 2 is preferred, as it would cost-effectively address the associated failure risks.

For the fibre-optic plant replacement and expansion, the do nothing option would leave parts of Toronto Hydro's system without requisite infrastructure to support SCADA penetration and network innovation. The proposed approach is cost effective and leverages existing plant installed under an approved program from the 2015 CIR application.

For the Underground Radio Expansion, the do nothing option would not resolve the existing safety and operational issues in vaults located underground, at levels P2 or below. As an alternative to radio expansion, Toronto Hydro considered using bi-directional amplifiers to enhance the radio signal into the vault and installing a permanent radio similar to that used in Toronto Hydro's truck fleet. The proposed approach, a solution that leverages existing portable radios, was found to address the operational and safety risks more cost-effectively than the alternatives.

E8.4.6 Execution Risks & Mitigation

This section discusses various potential risks to the execution of the IT/OT program, and Toronto Hydro's corresponding mitigation measures:

- **Internal Resource Availability:** There may be insufficient resources to complete the planned program tasks and activities, which could delay interdependent and downstream work activities and lead to escalations in project costs due to the need to procure temporary skilled resources at a premium. In response, Toronto Hydro will: (i) adopt a long term resource plan based on project tasks and activities that the utility plans to undertake over the 2020-2024 period; and (ii) ensure appropriate responsibility overlaps between labour resources to minimize impact from attrition.

- **Vendor Management:** Vendors may not meet program delivery obligations or may change the product cost structure. More specifically, a vendor may be unable to provide the product according to project schedule or in compliance with Toronto Hydro's specifications, thereby leading to delays or cost overruns to address the issue. In this regard, Toronto Hydro will adopt the following mitigation measures to ensure contractual mechanisms are available as well as to oversee and enforce contract terms and conditions:
  - Clearly state expected timelines and have resolution clauses to address delays.
  - Identify an escalation path to quickly resolve conflicts and discrepancies.
  - Enforce short interval control through vendor project status updates and reports.
  - Complete comprehensive due-diligence of scope and requirements prior to undertaking projects and incorporate findings in the tender documentation.
  - Enter into long term contracts, where appropriate, with vendors and suppliers to ensure costs are fixed over a long period of time.
  - Solicit vendor responses to competitive bids from qualified parties.
- **Technology Change:** New technology may be introduced after previous assets were refreshed during the asset's lifecycle. This risk may impact project cost, as new technology may need to be procured to meet business requirements. Toronto Hydro closely monitors the latest trends to determine how technology fits into existing Toronto Hydro IT standards and business requirements.
- **Adherence to Budget & Timelines:** If a project tracks above budget or falls behind schedule, this could take resources away from other important IT projects and delay their implementation. To address this risk, Toronto Hydro uses modern project management methods, tools, and vendor agreements to ensure on-time and on-budget project execution. Moreover, Toronto Hydro's experienced project managers will control the implementation timing of projects in accordance with each project plan and emerging risks. Contract tools and incentives will also be incorporated to aid the management of timelines.
- **Project Delivery**: A new IT/OT System version could cause established core business processes to change and, without proper integration, could disrupt, and cause inefficiencies in these processes. Toronto Hydro undertakes extensive regression testing and user testing prior to rolling out the final upgrade to the business units. In addition, risks are mitigated

through appropriate user engagement and communication, change management, and project governance including contingencies to minimize the impact to the business users in the final implementation.

- **Regulatory Requirements:** Currently unknown new regulatory requirements can require additional resources and time to implement. If new regulatory requirements emerge at a higher than expected rate, resources will be re-allocated to ensure that Toronto Hydro complies with application requirements. Projects will be rescheduled as necessary in accordance with the project prioritization considerations outlined in section E8.4.4.4 above.
- **IT/OT Systems Integration:** Different systems may not be properly integrated with each other when a system or group of systems are upgraded or replaced. If the current level of integration is not maintained, business processes could be impeded and process inefficiencies could be introduced from manual data updates. Toronto Hydro considers and analyzes new component configurations in defining project scopes, and conducts thorough due diligence during technical feasibility studies.
- **Software Release Dates:** Changes to application version release dates will impact the project schedule and potentially impact downstream projects in the program. If one or more software upgrades require another software upgrade to be completed first, any delay in the release of the first software upgrade will delay the upgrade of the dependent software system(s). To address this risk Toronto Hydro monitors release dates, ensures that all impacted projects are properly sequenced, follows best practices in project management, and maintains a holistic view of IT environment/architecture to identify interdependencies.
- **Solution Fit to Utility Requirements**: A design approach that considers functionalities in isolation is particularly risky. The solutions proposed for incorporation into the upgraded and expanded IT systems must be able to deliver the functionality Toronto Hydro requires to meet its operational, regulatory, and customer obligations. Toronto Hydro will fully consider all areas of its operations before any configuration or coding has taken place. All processes and system requirements will be defined and documented by Toronto Hydro prior to tools, components and modules selection, and integration. End-to-end operational process scenarios will be used in the testing phase of the system.

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 2B
Section E8.4
Appendix A
ORIGINAL
(35 pages)

IT Budget Assessment Final Report

16 March 2018

Prepared for: Torys LLP

Project Number: 330045299

GARTNER CONSULTING

Executive Summary

- In connection with THESL's upcoming distribution rate application, Gartner completed a peer benchmark of the THESL IT budget.
  - The assessment included a comparison of high level IT metrics and spending and staffing distributions with a view to providing insight into how IT spending aligns with peer organizations.
- For 2017, THESL IT Spending as a Percentage of Revenue and of Operational Expense are both lower than the peer group (2.2% vs 2.5% and 2.4% vs 3.1% respectively).
  - Infrastructure support cost is also less than other peer organizations would spend to support the same workload – $32.4M compared to $37.1M (12.6% or 4.5M less).
- Distribution of spending by cost category, investment category and functional area are all comparable to the peer group, with some variation but no significant issues identified.
- THESL also provided Gartner a forecast for 2020 spending and staffing in addition to 2017 data.
- Results of the comparison of the 2020 forecast to the 2017 peer group show similar results.
  - For 2020, THESL IT Spending as a Percentage of Revenue and of Operational Expense are both lower than the peer group (2.3% vs 2.5% and 2.7% vs 3.1% respectively).
- As in 2017, the distribution of spending by cost category, investment category and functional area are all comparable to the peer group, with some variation but no significant issues identified.
- THESL did not forecast infrastructure workload or users, so Gartner did not calculate comparable infrastructure efficiency or employee-based metrics for 2020 data.

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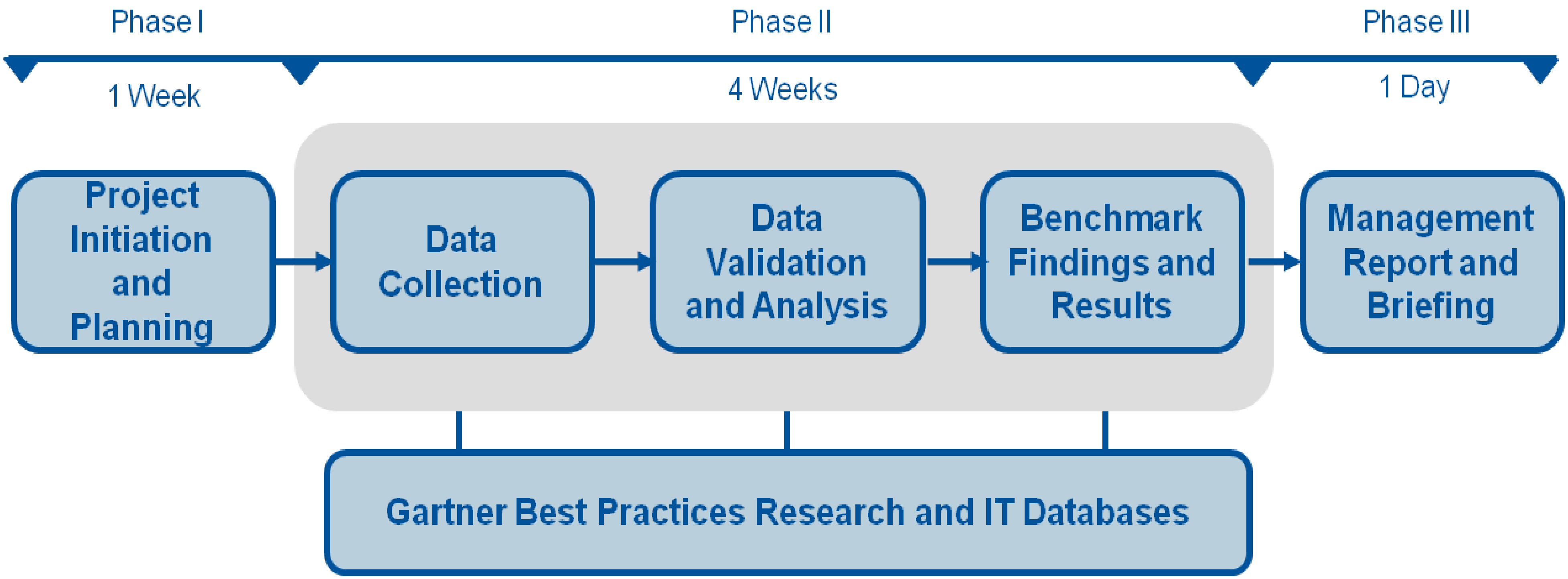
Contents

Project Background and Objectives

- In connection with THESL's upcoming distribution rate application, Gartner has conducted an assessment of the THESL IT budget.
  – The assessment includes a comparison of high level IT metrics and spending and staffing distributions with a view to providing insight into how IT spending aligns with peer organizations.

Benchmark Analysis Methodology
IT Budget Assessment Project Schedule

At a high level, the project specific tasks and timeline are shown in the figure below:



Torys provided data collected by THESL staff based on Gartner data definitions. Gartner conducted a data validation with the teams to ensure data definitions were followed and the comparative results are accurate.

Benchmark Analysis Methodology
Key Concepts

- **Revenue**: The enterprise revenue associated with the business units supported by the IT organization.
- **Operational Expense**: Enterprise expense equals the expense associated with the business units supported by the IT organization.
- **IT Budget /Spend**: The best estimate of total spend at the end of the twelve month budget period for information technology to support the enterprise. IT Budget/Spending can come from anywhere in the enterprise that incurs IT costs, and it is not limited to the IT organization. It is calculated on an annualized "cash out" basis and therefore contains capital spending, and operational expenses, but not depreciation and amortization. IT budget/spending information collected from clients typically does not include:
  - Costs for technology or services that are resold - An example of this is salaries for developers involved in building commercially packaged software.
  - Operational technology that is equipment built or purchased for non data processing purposes but which has computerized components – Examples of this include robotic manufacturing machines, Automated Teller Machines, specialized point of sale devices, scanners, blood pressure monitors etc.
  - Depreciation or amortization expenses as that could lead to double counting from an accounting perspective.
  - Internal "cross charges" and corporate allocations related to expenses such as, early retirement, incentive bonuses, human resources, and chairperson's salary etc.
  - Business data subscriptions and services (such as Bloomberg), even if they are managed by the IT organization.

Benchmark Analysis Methodology
Definitions for Run, Grow and Transform Allocation

Business Value Category Decision Tree for Run, Grow and Transform the Business IT Spending Allocation

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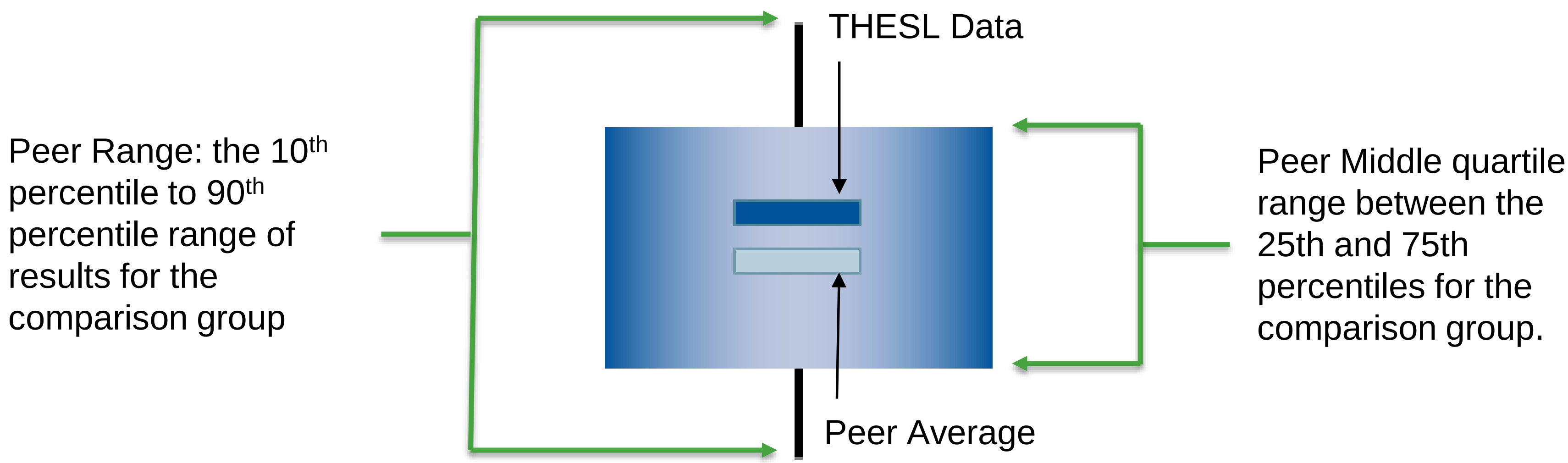
- **Transform the Business**: This is an indicator of how much of the IT resource is consumed and focused on implementing technology systems that enable the enterprise to enact new business models. This is very much a "venture" category and would be represented by activities such as an insurer introducing usage-based insurance products such as telematics or a supermarket combining real time analytic monitoring with in-store task management to provide automated alerts to store staff to perform preemptive tasks.
- **Run the Business**: This is an indicator of how much of the IT resource is consumed and focused on the continuing operation of the business. It includes all non-discretionary expense as part of the Run the Business Cost.
- **Grow the Business**: This is an indicator of how much of the IT resource is consumed and focused on developing and enhancing IT systems in support of business growth (typically organic growth) or improvement. Discretionary investments are included in the Grow/Improve the Business Cost.

Benchmark Analysis Methodology
Peer Comparisons

THESL's results are displayed in comparison with the following reference points:



Differences in spending and staffing metrics derived from this analysis provide insight into current strategic IT investment levels relative to business performance and scale vs. the competitive landscape.

These measures should also be considered within the context of future state business objectives.

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Benchmark Analysis Methodology
Peer Comparisons

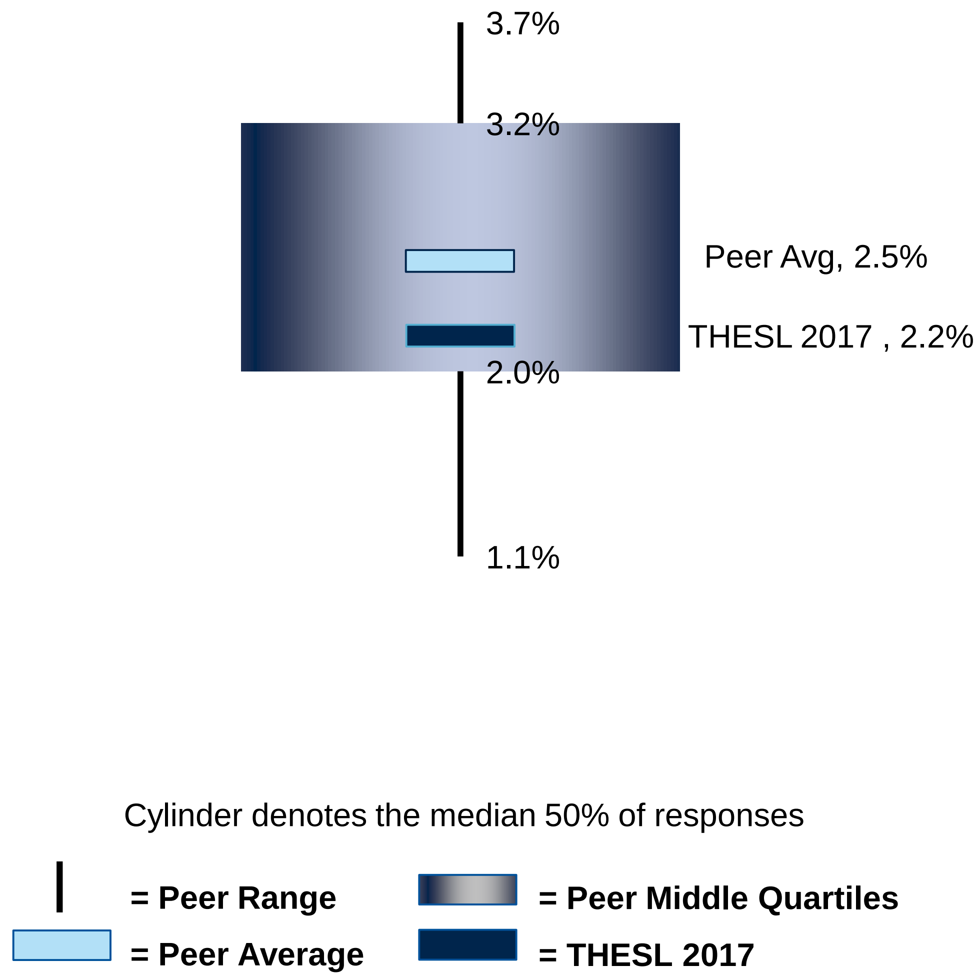
- A peer group of 15 Utilities was selected based on industry and revenue.
  – The same peer group is used for both the 2017 and projected 2020 results.

	THESL 2017	THESL 2020	Peer Average
Revenue (millions)	$4,016.9	$4,042.5	$4,477.8
Operational Expense (millions)	$3,572.7	$3,447.5	$3,659.8
Organization Employees	1,390	1,467	4,730
Organization Users (from Active Directory)	3,430	N/A	N/A
IT FTEs	214	200	305
IT Capital and Operational Expense (millions)	$87.1	$92.9	$110.4
Customers	758,193	784,095	1,233,000

  – Peer geographic distribution is 7 United States, 4 Canada and 4 Western Europe.
  – All serve major urban locations.
  – THESL 2017 data is based on 11 months of actuals plus one month estimate to complete.

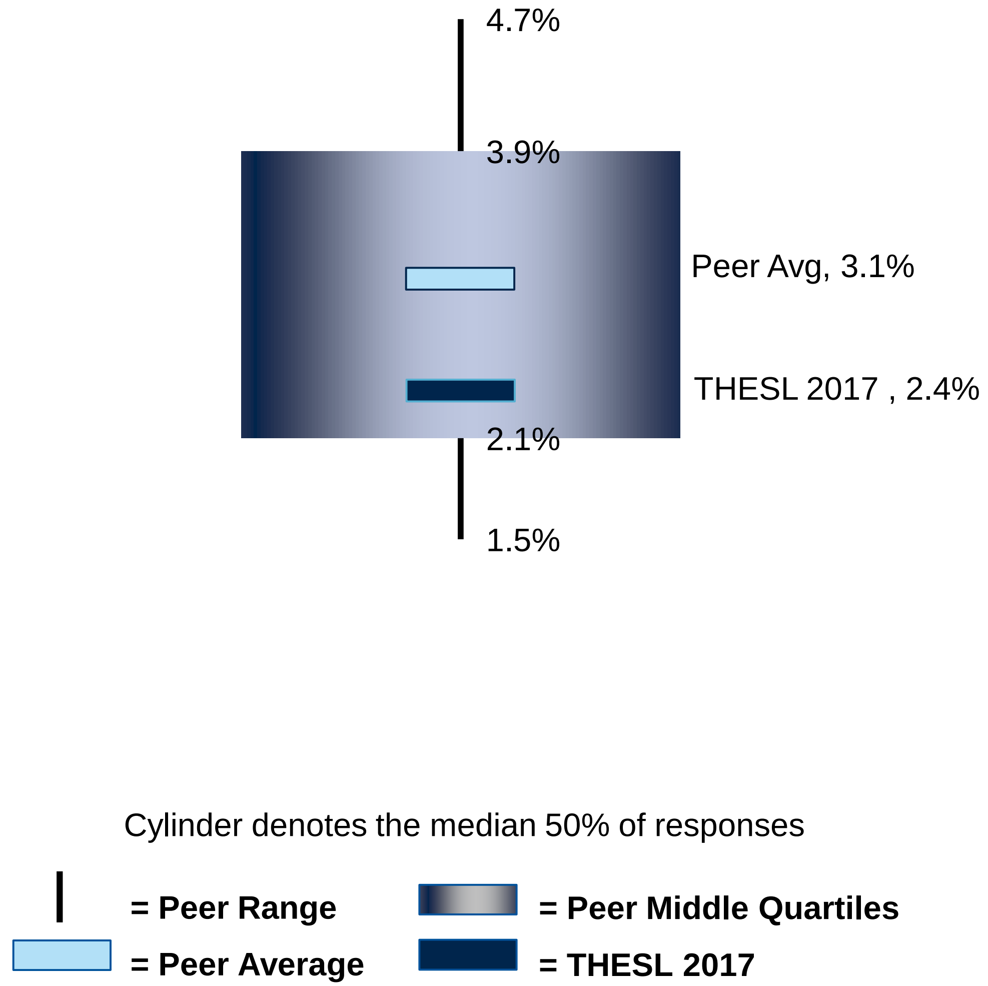
Results for Fiscal Year 2017

2017 IT Spending as % of Revenue



- IT Spending as a Percentage of Revenue for THESL is about 14% less than the peer group, 2.2% compared to 2.5%.
  - IT Spending as a Percentage of Revenue is a common measure of IT's role in the business, and a measure to assess the comparative level of spending with industry peers.
- Being above or below average does not necessarily mean spending is "too high" or "too low."

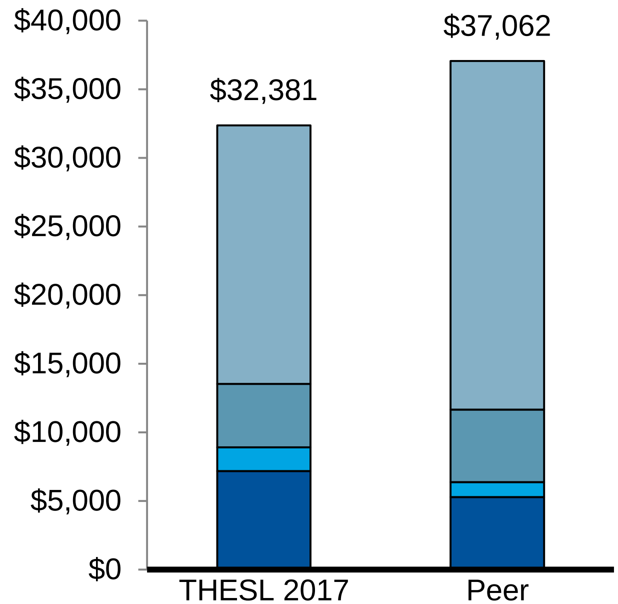
2017 IT Spending as % of Operational Expense



- IT Spending as a Percentage of Operational Expense for THESL is about 22% less than the peer group, 2.4% compared to 3.1%.
  - – IT Spending as a Percentage of Operational Expense provides a view of the role IT plays in business spending patterns: the greater the amount of operating expenses is dedicated to IT, the greater the business generally requires visibility into IT investments.

Infrastructure Support Efficiency

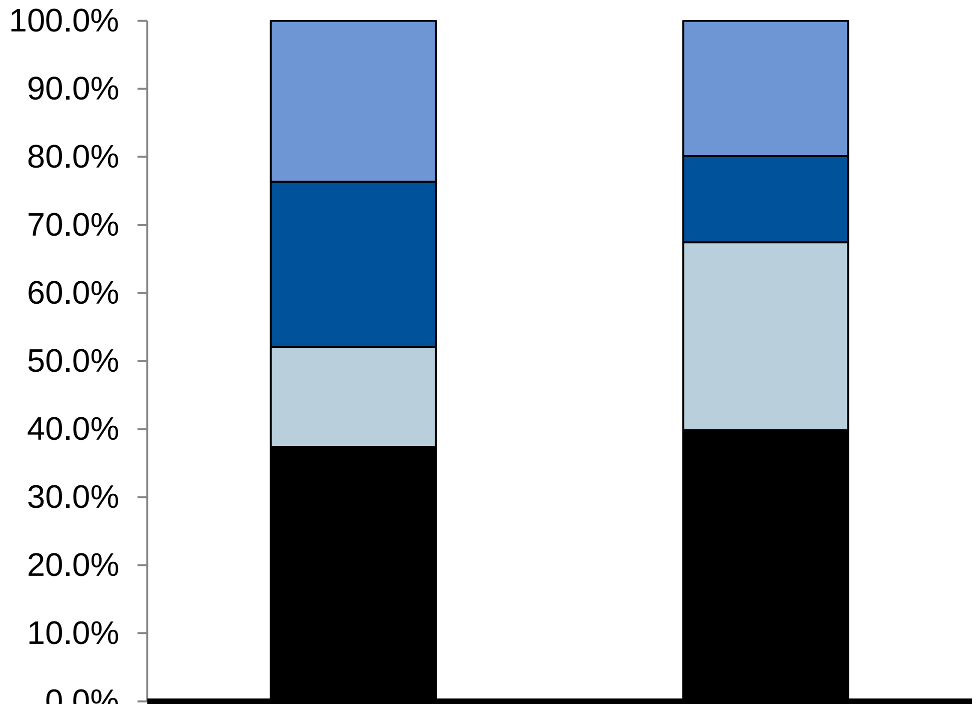
THESL 2017 IT infrastructure spending is 13% ($4.7M) less than organizations of similar size would spend to support the same workload, $32.4M compared to $37.1M.



	THESL 2017	Peer
Data Center	$18,849	$25,412
End-User Computing	$4,625	$5,274
IT Service Desk	$1,724	$1,097
Voice & Data Networking	$7,183	$5,279
Total	$32,381	$37,062

- THESL provided 2017 infrastructure workload measures in addition to IT spending and staffing budgets and distributions, allowing this comparison of infrastructure costs to Gartner benchmark database averages.
  - 441 Unix OS Instances
  - 1,464 Windows OS Instances
  - 252 Linux x86 OS Instances
  - 4,041 TBs Raw Storage
  - 4,038 Personal Computing Devices
  - 49,301 IT Service Desk Contacts
  - 3,430 Active Directory User Accounts (Voice & Data Users)
- Gartner allocated 48% of THESL Corporate IT Management and IT Finance & Administration to infrastructure spending (infrastructure is 48% of total infrastructure and applications).
  - Within the Gartner database, these costs are included in the detailed infrastructure metrics but not broken out separately.
- *Note that 2020 infrastructure workload measures have not been forecast so there is no comparison for the 2020 period.*

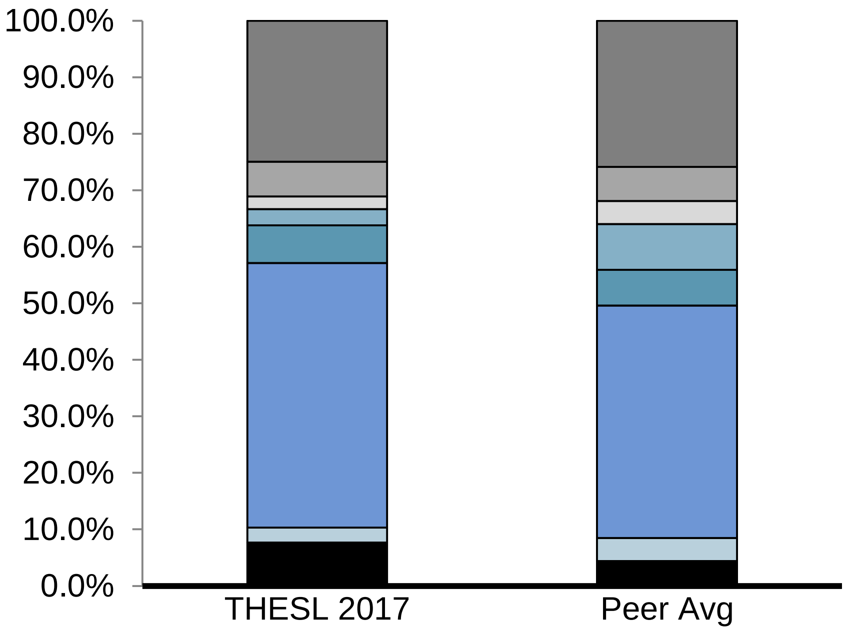
2017 Spending Distribution by Cost Category



	THESL 2017	Peer Avg
Outsourcing	23.6%	19.9%
Hardware	24.3%	12.7%
Software	14.7%	27.6%
Personnel	37.4%	39.8%

- The distribution of spending between hardware, software, personnel and outsourcing shows a lower distribution of spending for Software than the peers, but higher for Outsourcing and Hardware.
  – The distribution of spending for Personnel is also slightly lower.
- This distribution represents a "capital view" of IT spend which includes current-year capital and operational spending (and excludes depreciation and amortization).

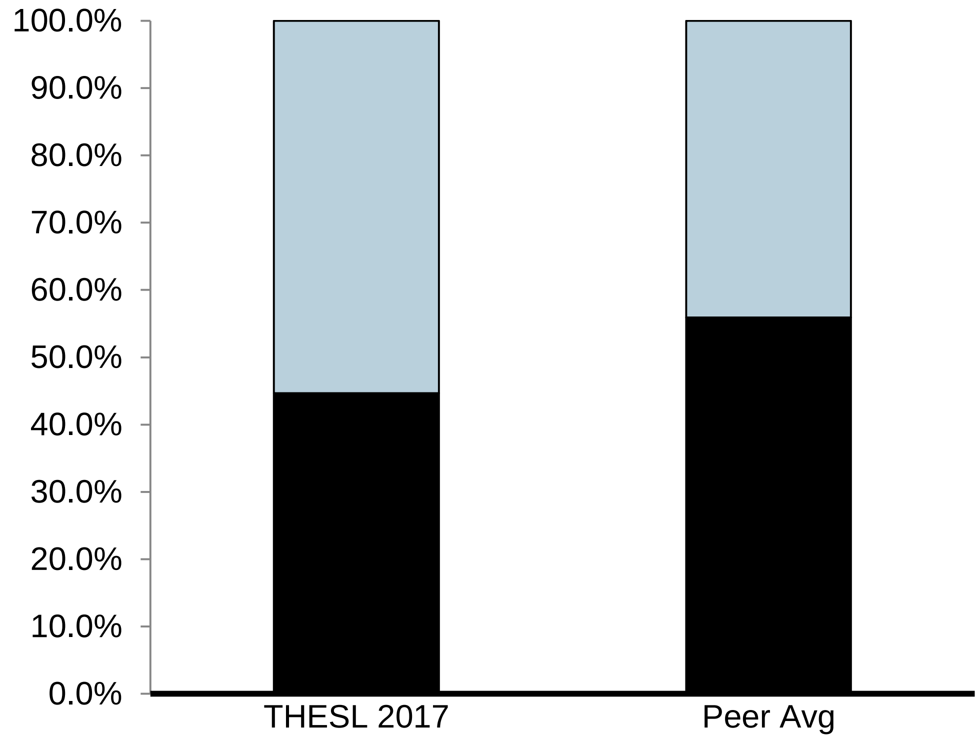
2017 Spending Distribution by IT Functional Area



	THESL 2017	Peer Avg
Data Center	25.0%	25.9%
End-User Computing	6.1%	6.0%
IT Service Desk	2.3%	4.1%
Voice Services	2.8%	8.1%
Data Networking	6.7%	6.3%
App Dev & Support	46.9%	41.2%
Corporate IT Mgmt	2.6%	4.1%
Finance & Admin	7.7%	4.4%

- The distribution of spending by functional area provides a view of key IT resource consumption.
- The distribution of spending for IT Service Desk and Voice Services are lower than the peer group, while Applications is slightly higher.
  - Combined Corporate IT Management, Finance & Administration is also slightly higher than the peer group.
- This distribution represents an “expense view” of IT spend which includes current-year operational expense as well as current-year lease, maintenance, depreciation and amortization expense.

2017 Spending Distribution – Capital and Operational Spend



	THESL 2017	Peer Avg
Capital	55.4%	44.1%
Operations	44.6%	55.9%

- For 2017, the percentage of the IT budget for Capital is greater than the peer group, while the percentage of spending for Operations Expense is lower.
- IT capital expenses vs. operational expenses helps to portray the investment profile for an organization in a given year.
  – In 2017, an ERP replacement project contributes to a high percentage of spending on capital projects.

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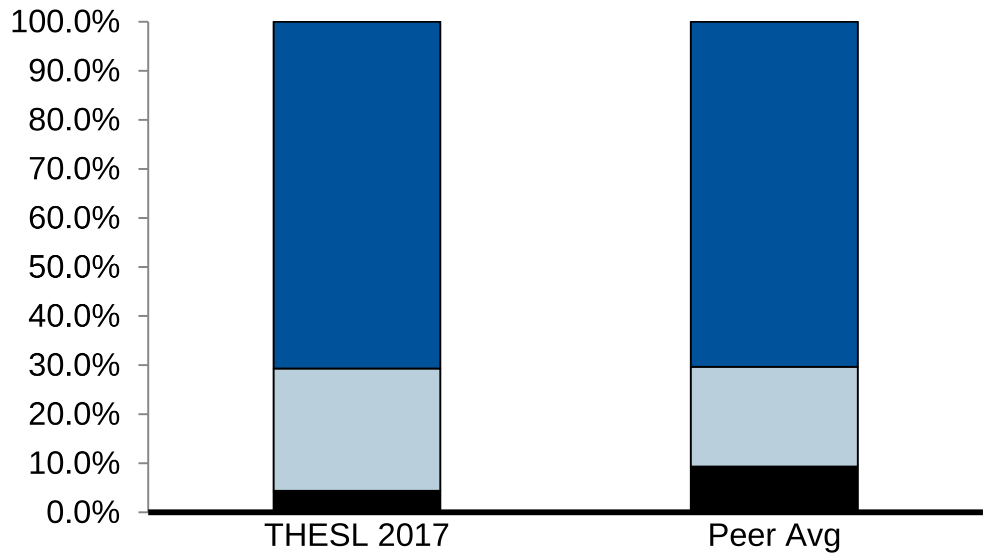
2017 Spending Distribution – Run, Grow, Transform

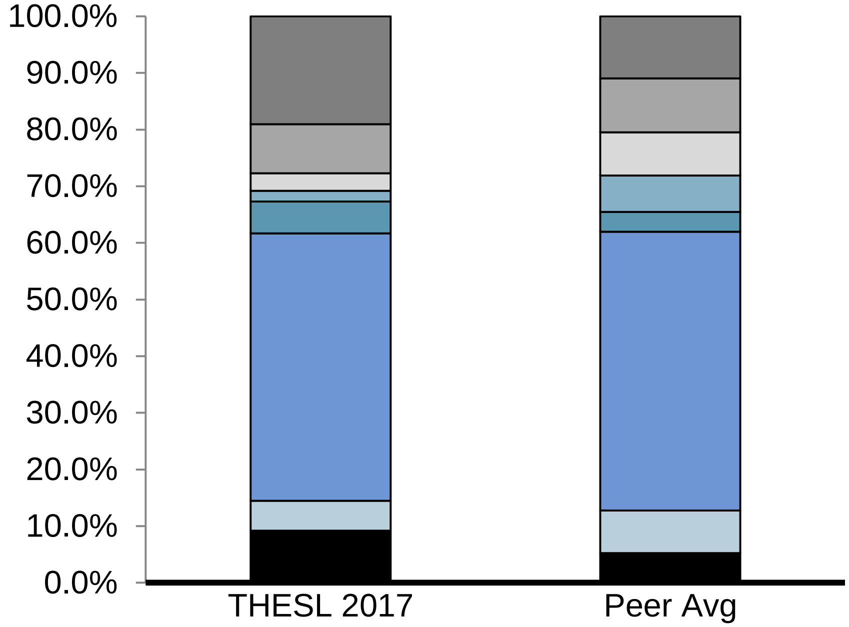


	THESL 2017	Peer Avg
Run	70.7%	70.3%
Grow	24.9%	20.3%
Transform	4.4%	9.3%

- The distribution of the IT Budget categorized as Run, Grow and Transform is similar to the peer group.
- The distribution of IT spending to "run," "grow" and "transform" the business provides a view of the investment profile in business terms.

Gartner

2017 Staffing Distribution by IT Functional Area



	THESL 2017	Peer Avg
Data Center	19.0%	10.9%
End-User Computing	8.7%	9.5%
IT Service Desk	3.1%	7.6%
Voice Services	1.9%	6.4%
Data Networking	5.6%	3.5%
App Dev & Support	47.2%	49.2%
Corporate IT Mgmt	5.3%	7.5%
Finance & Admin	9.2%	5.2%

- Data Center and Data Networks have a higher percentage of staffing than the peer group.
- The percentage of Finance & Admin staffing is also higher.

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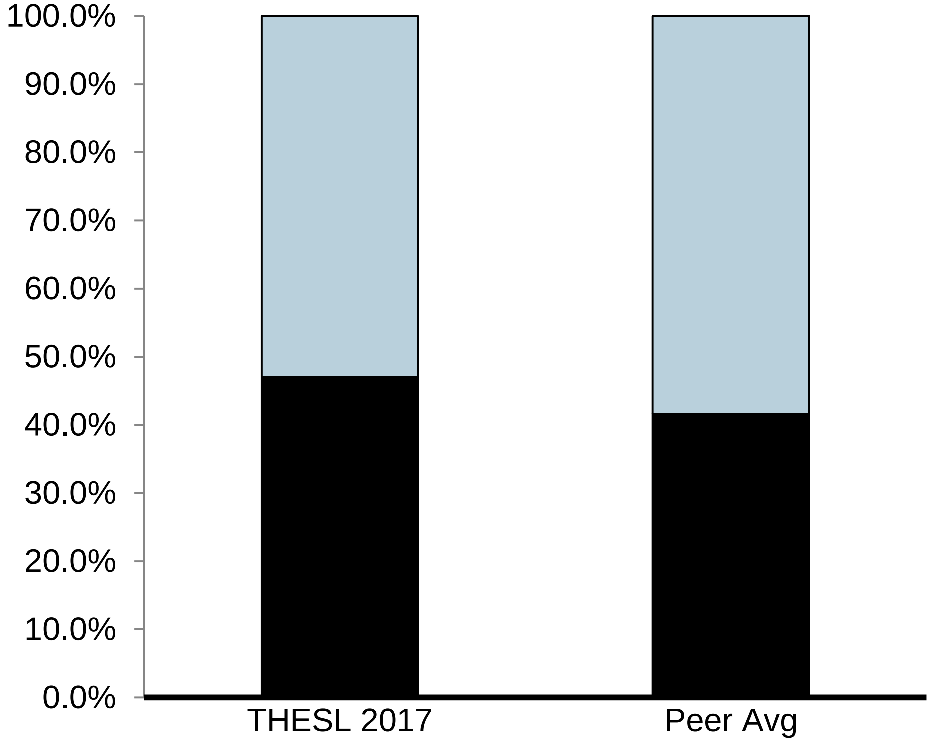
2017 IT Contractor Usage



	THESL 2017	Peer Avg
In House	53.0%	58.4%
Contractors	47.0%	41.6%

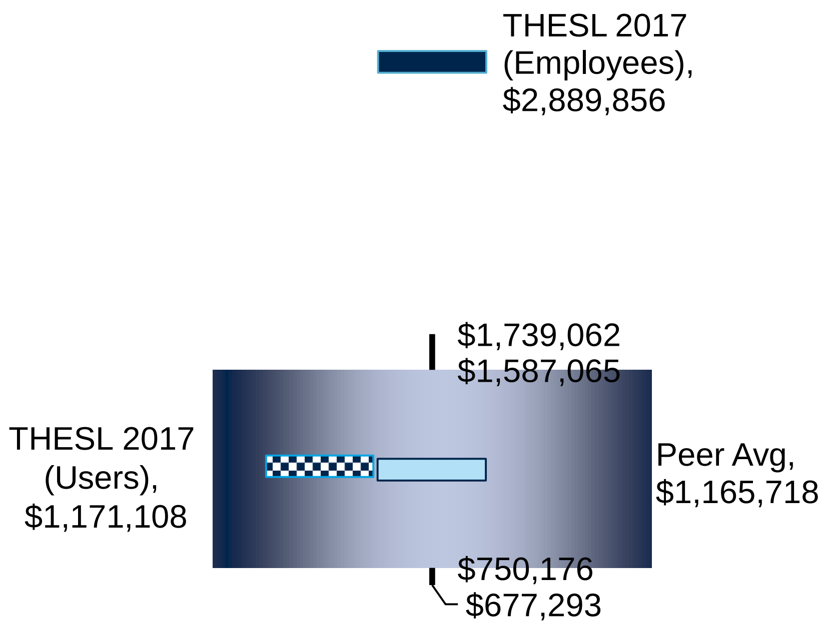
- THESL and the peer group both rely on a high percentage of contractor IT staff.
  - This distribution provides a reflection of the IT staffing strategy and can be useful in managing support when there are fluctuating demands for IT services.

Employees versus Users at THESL

- Gartner typically collects the number of employees for an IT Budget Assessment, and bases three standard metrics on employee count: Revenue per Employee, IT Spending per Employee and IT FTEs as a Percentage of Employees.
  - Many of the IT departments Gartner works with and has in our peer benchmark database typically do not know the number of contractor labour or level of outsourcing in the lines of business, and Gartner does not normally collect a number of users.
- As with other measures comparing IT spending to business measures, these three metrics can be influenced by both the numerator and denominator.
- For THESL, these three metrics appear to be skewed compared to the peer group based on the employee count, rather than by IT spending and staffing.
- As a test of this assumption, Gartner computed metrics using THESL number of Users rather than Employees and compared results.
- While metrics based on Employees are about 2.2 to 2.5 times greater than the peer group, the results based on Users are between 0 and 10% less than the peer group.
  - The metrics based on Users are in line with the other metrics (IT Spending as a Percentage of Revenue and Operational Expense), supporting the assumption that it is THESL employee count not IT spending or staffing that drives the results on the next three slides.

Note that the number of Users has not been forecast for the 2020 period, so Gartner has not reported 2020 results for these metrics.

2017 Revenue Per Employee

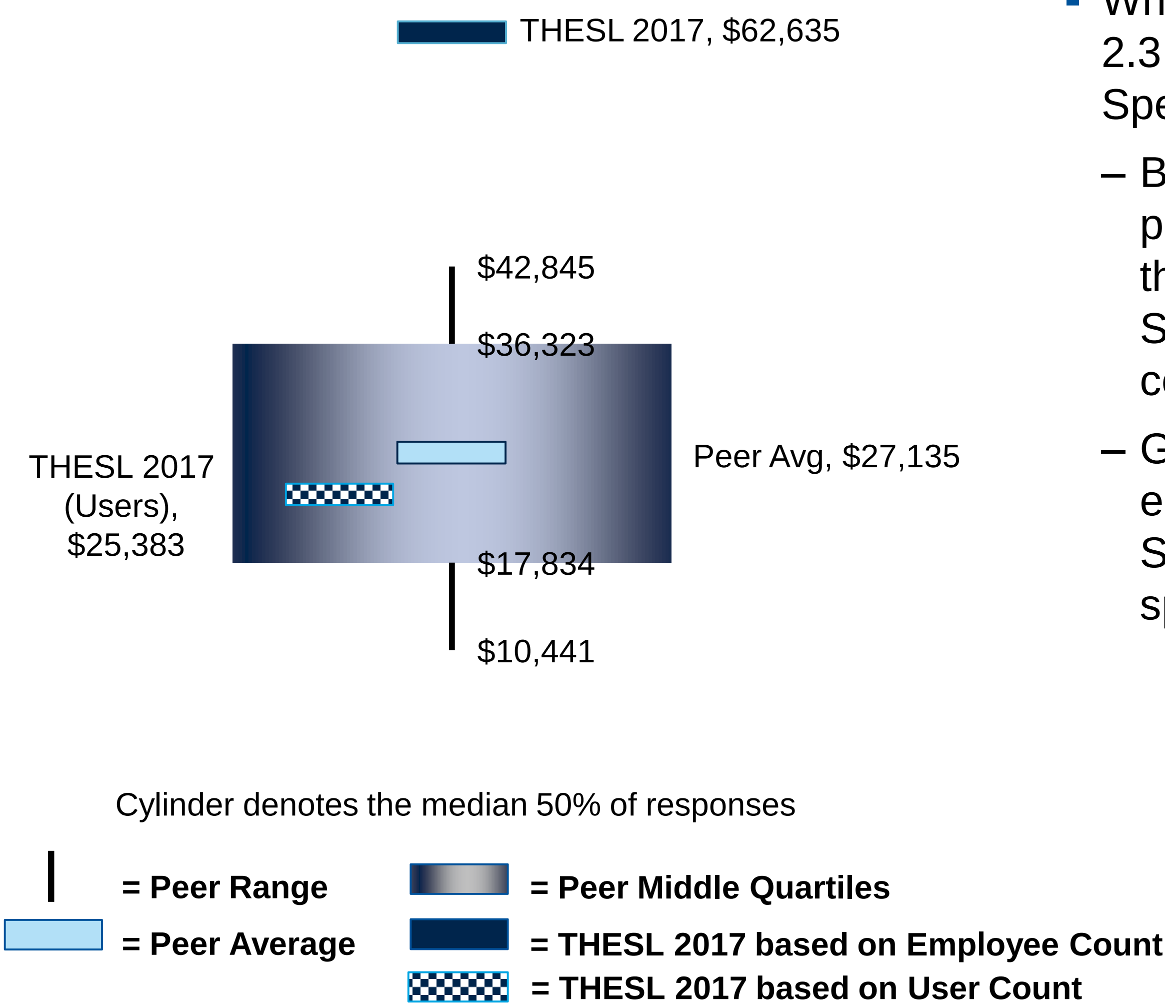


Cylinder denotes the median 50% of responses

= Peer Range
= Peer Middle Quartiles
= Peer Average
= THESL 2017 based on Employee Count
= THESL 2017 based on User Count

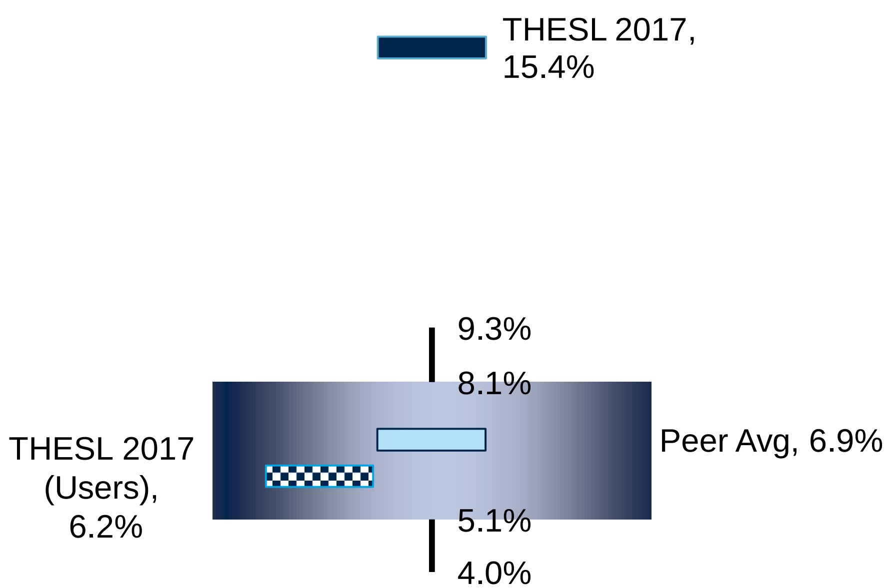
- THESL Employee count is comparatively lower than the peer group, reflected in Revenue per Employee.
- Based on 3,430 Users from THESL Active Directory, Revenue per User is roughly equivalent to the peer group Revenue per Employee.
  - This suggests that THESL lines of business may have a higher reliance on contract or outsource support than the peer group.

2017 IT Spending Per Employee



- While IT Spending per Employee is about 2.3 times greater than the peer group, IT Spending per User is about 6.5% less.
  - Based on the comparison of Revenue per Employee and Revenue per User to the peer group, Gartner believes that IT Spending per User represents a better comparison for THESL.
  - Gartner believes that a relatively lower employee count skews results for IT Spending per Employee, not higher IT spending.

2017 IT FTEs as % of Total Employees



Cylinder denotes the median 50% of responses

= Peer Range

= Peer Average

= Peer Middle Quartiles

= THESL 2017 based on Employee Count

= THESL 2017 based on User Count

- While IT FTEs as a Percentage of Total Employees is about 2.2 times greater than the peer group, IT FTEs as a Percentage of Total User is about 9.6% less.
  – Based on the comparison of Revenue per Employee and Revenue per User to the peer group, Gartner believes that IT FTEs as a Percentage of Total User represents a better comparison.
  – Gartner believes that a relatively lower employee count skews results for IT FTEs as a Percentage of Total Employees, not higher IT staffing.

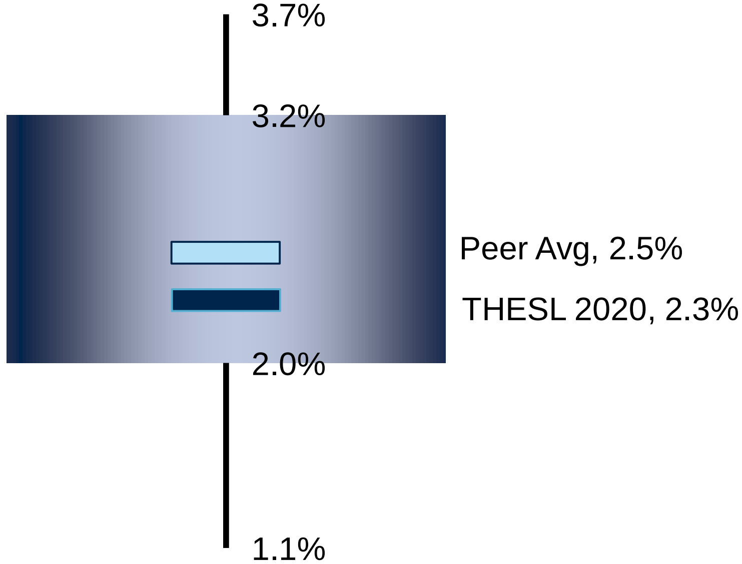
Gartner

Projected Results for Fiscal Year 2020

Projected IT Budget Results for 2020

- THESL provided a forecast for business and IT measures for 2020.
- Gartner has compared these forecasts to the IT spending and staffing metrics for the 2017 peer group.
  - Gartner does not have comparable forecasts for the peers.
- Results for this forecast may differ from actual results for THESL based on the accuracy of the forecast.
- Not all measures were forecast, so not all metrics for the projected 2020 period can be reported.
  - Infrastructure workload measures were not forecast for 2020 so no comparison of efficiency for infrastructure support is provided.
  - User count was not forecast for 2020. As discussed in 2017 results, THESL has a comparatively low number of employees which skews results for employee-based metrics. As such, Gartner has not calculated or reported results for Revenue per Employee and per User, IT Spending per Employee and per User, or IT FTEs as a Percentage of Employees and Users.

Projected 2020 IT Spending as % of Revenue



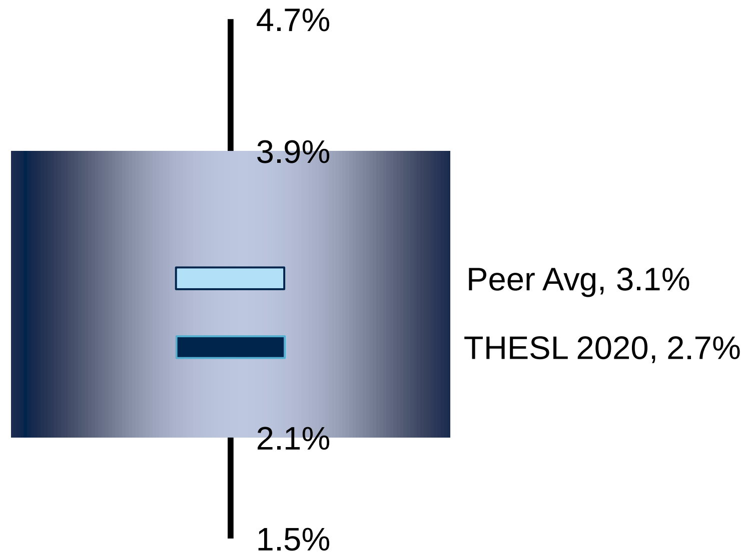
- Forecast IT Spending as a Percentage of Revenue for THESL in 2020 is about 9% less than the 2017 peer group, 2.3% compared to 2.5%.

Cylinder denotes the median 50% of responses

= Peer Range **= Peer Middle Quartiles**

= Peer Average **= THESL 2020**

Projected 2020 IT Spending as % of Operational Expense



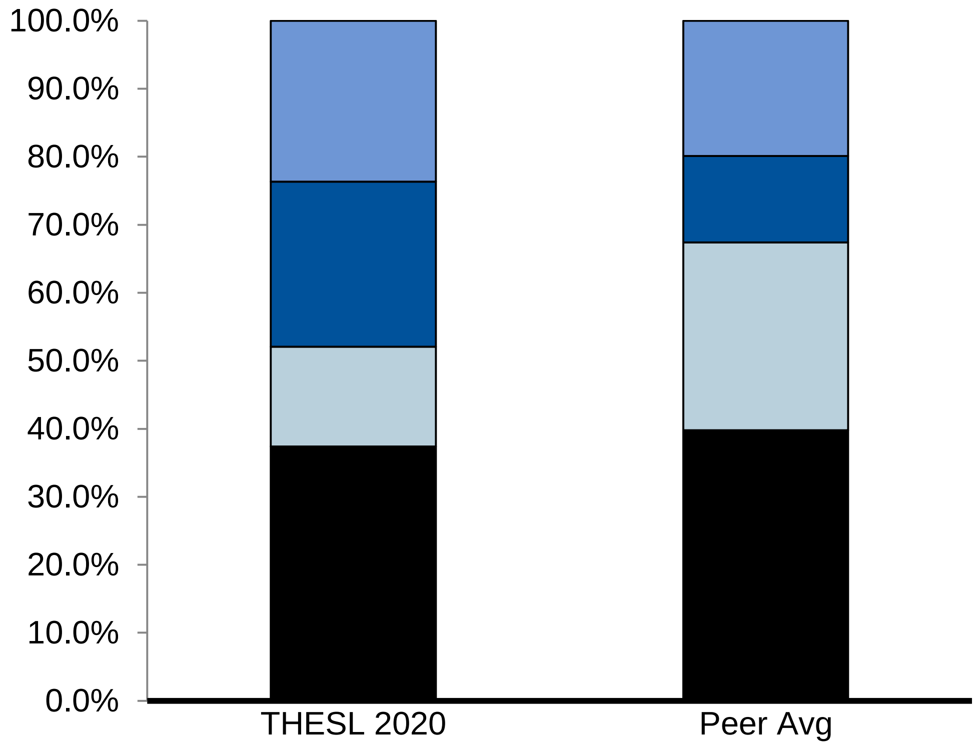
- IT Spending as a Percentage of Operational Expense for THESL is about 13% less than the 2017 peer group, 2.7% compared to 3.1%.

Cylinder denotes the median 50% of responses

= Peer Range **= Peer Middle Quartiles**

= Peer Average **= THESL 2020**

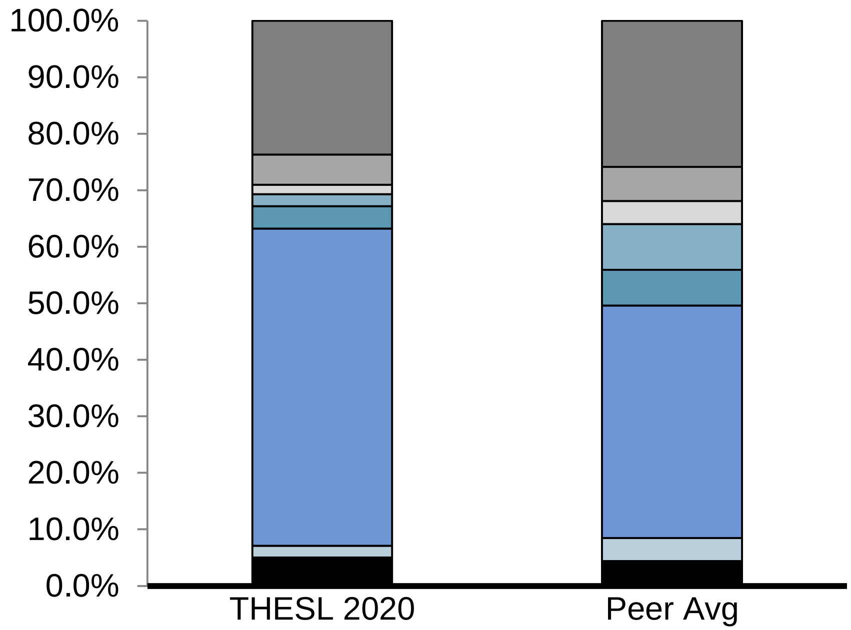
Projected 2020 Spending Distribution by Cost Category



	THESL 2020	Peer Avg
Outsourcing	23.6%	19.9%
Hardware	24.3%	12.7%
Software	14.7%	27.6%
Personnel	37.4%	39.8%

- The distribution of spending between hardware, software, personnel and outsourcing forecast for 2020 is the same as in 2017, and shows a lower distribution of spending for Software than the peers, but higher for Outsourcing and Hardware.
  - The distribution of spending for Personnel is also slightly lower.

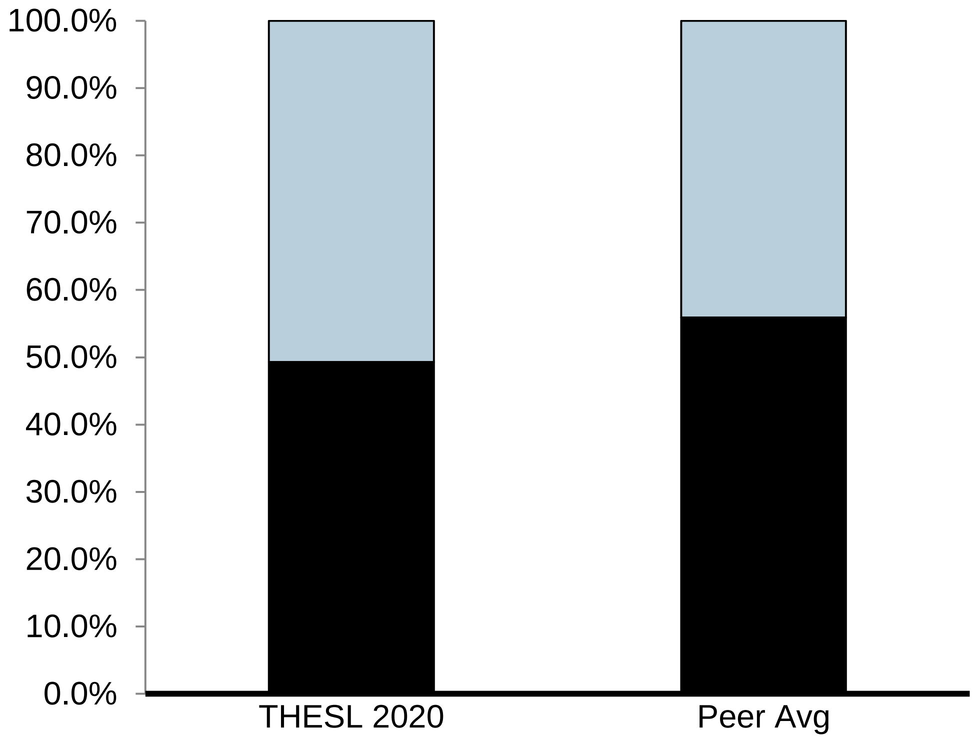
Projected 2020 Spending Distribution by IT Functional Area



	THESL 2020	Peer Avg
Data Center	23.7%	25.9%
End-User Computing	5.3%	6.0%
IT Service Desk	1.6%	4.1%
Voice Services	2.1%	8.1%
Data Networking	4.0%	6.3%
App Dev & Support	56.1%	41.2%
Corporate IT Mgmt	2.1%	4.1%
Finance & Admin	5.0%	4.4%

- The forecast distribution of spending for Applications is slightly higher than in 2017, while all other areas are slightly lower.
- Compared to the 2017 peer group, the percentage of spending for Applications and for Finance & Administration are higher while all other areas are lower.
- This distribution represents an “expense view” of IT spend which includes current-year operational expense as well as current-year lease, maintenance, depreciation and amortization expense.

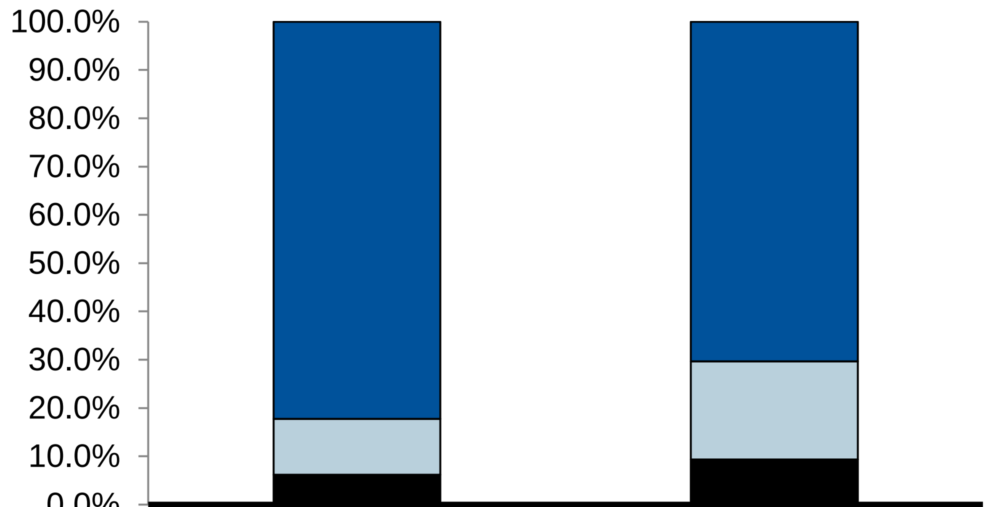
Projected 2020 Spending Distribution – Capital and Operational Spend



	THESL 2020	Peer Avg
Capital	50.7%	44.1%
Operations	49.3%	55.9%

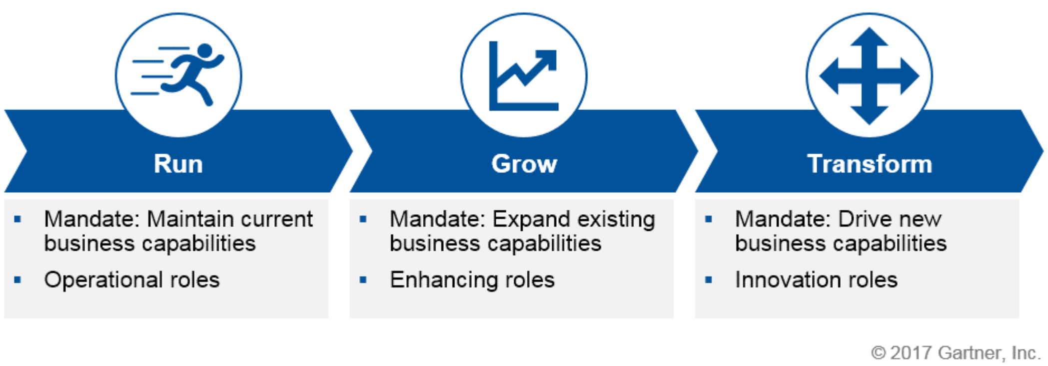
- For 2020, the percentage of the IT budget forecast as Capital is greater than the peer group, while the percentage of spending for Operations Expense is lower.
- The difference forecast for 2020 is slightly less than in 2017.
- IT capital expenses vs. operational expenses helps to portray the investment profile for an organization in a given year.

Projected 2020 Spending Distribution – Run, Grow, Transform



	THESL 2020	Peer Avg
Run	82.2%	70.3%
Grow	11.6%	20.3%
Transform	6.2%	9.3%

- The 2020 forecast for IT spending allocated to “Run” is greater than in 2017, and greater than the peer group.



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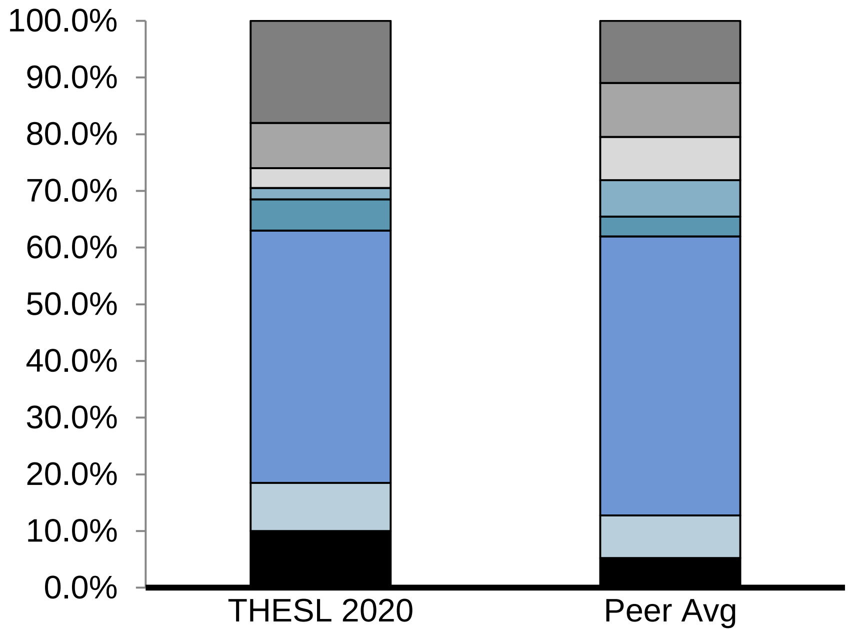
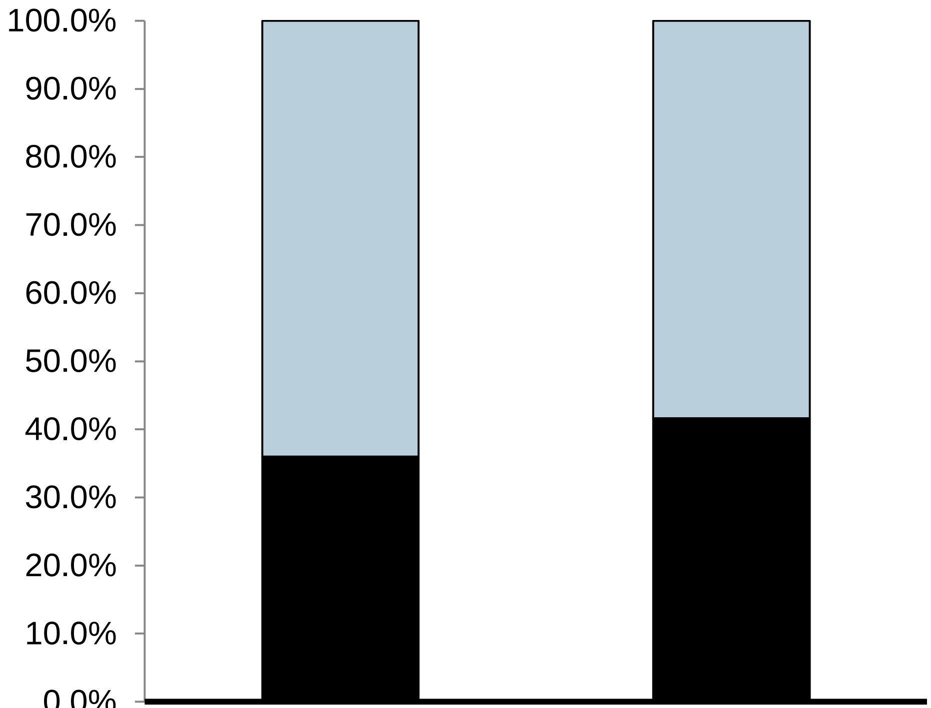
Projected 2020 Staffing Distribution by IT Functional Area



	THESL 2020	Peer Avg
Data Center	18.0%	10.9%
End-User Computing	8.0%	9.5%
IT Service Desk	3.5%	7.6%
Voice Services	2.0%	6.4%
Data Networking	5.5%	3.5%
App Dev & Support	44.5%	49.2%
Corporate IT Mgmt	8.5%	7.5%
Finance & Admin	10.0%	5.2%

- As in 2017, Data Center and Data Networks are forecast to have a higher percentage of staffing than the 2017 peer group.
- The percentage of Finance & Admin staffing is also higher.

Projected 2020 IT Contractor Usage



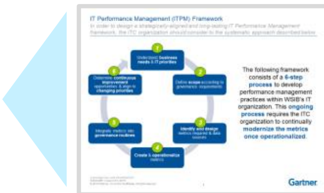
	THESL 2020	Peer Avg
In House	64.0%	58.4%
Contractors	36.0%	41.6%

- 2020 projected reliance on contractors for THESL is less than in 2017, and is lower than the 2017 peer group.

IT Performance Management (ITPM) Lifecycle

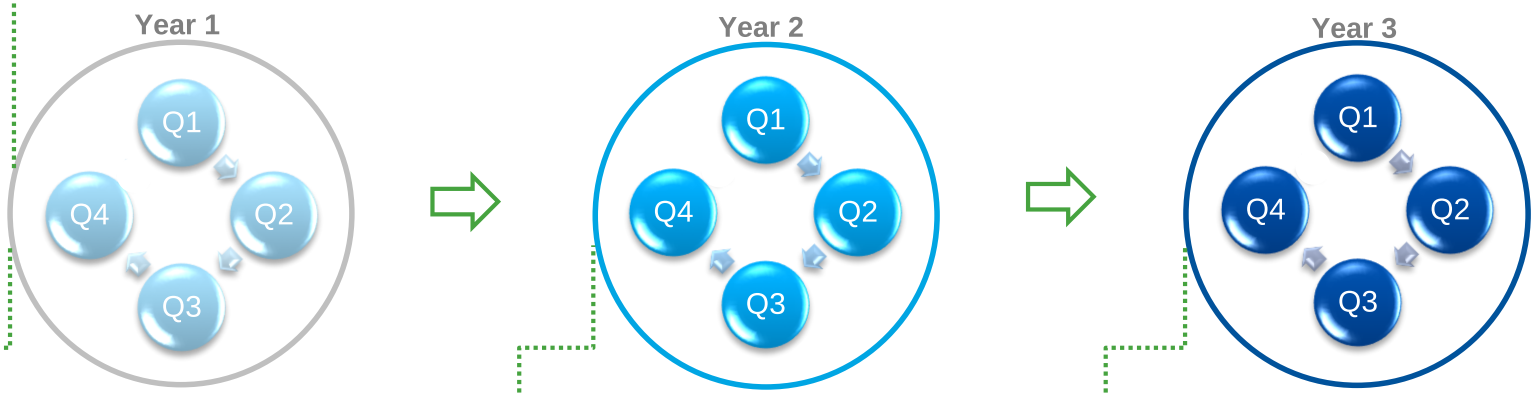
IT Performance Metrics

(***Quarterly***) *Execution and management of the IT Performance Management metrics portfolio and associated governance activities.*



A 3-year timeframe provides both the perspective required for a comprehensive IT performance management lifecycle, with a focus on periodic benchmarking and help desk sourcing.

3-Year IT Performance Management Cycle



Comprehensive Benchmark

(***Year 1***) *Consolidated and comprehensive benchmark analysis, including historical and peer group comparison*

Focused Benchmark: (e.g., *Data Center)*

(***Year 2***) *Based on the results from the Year 1 Comprehensive Benchmark, perform a detailed review and benchmark in a focus area*

Focused Benchmark: (e.g., *Help Desk Sourcing)*

(***Year 3***) *Based on the results from the Year 1 Comprehensive Benchmark, perform a detailed review and benchmark in a focus area*

Gartner

Contacts

Gartner Contacts

Nick Lal
Managing Partner
Gartner Consulting
Telephone: +1 416 228 7663
nicholas.lal@gartner.com

Tom Larson
Vice President
Gartner Consulting
Telephone: +1 925 413 0904
tom.larson@gartner.com

Tom Mitchell
Senior Director
Gartner Consulting
Telephone: +1 206 780 4445
thomas.mitchell@gartner.com

