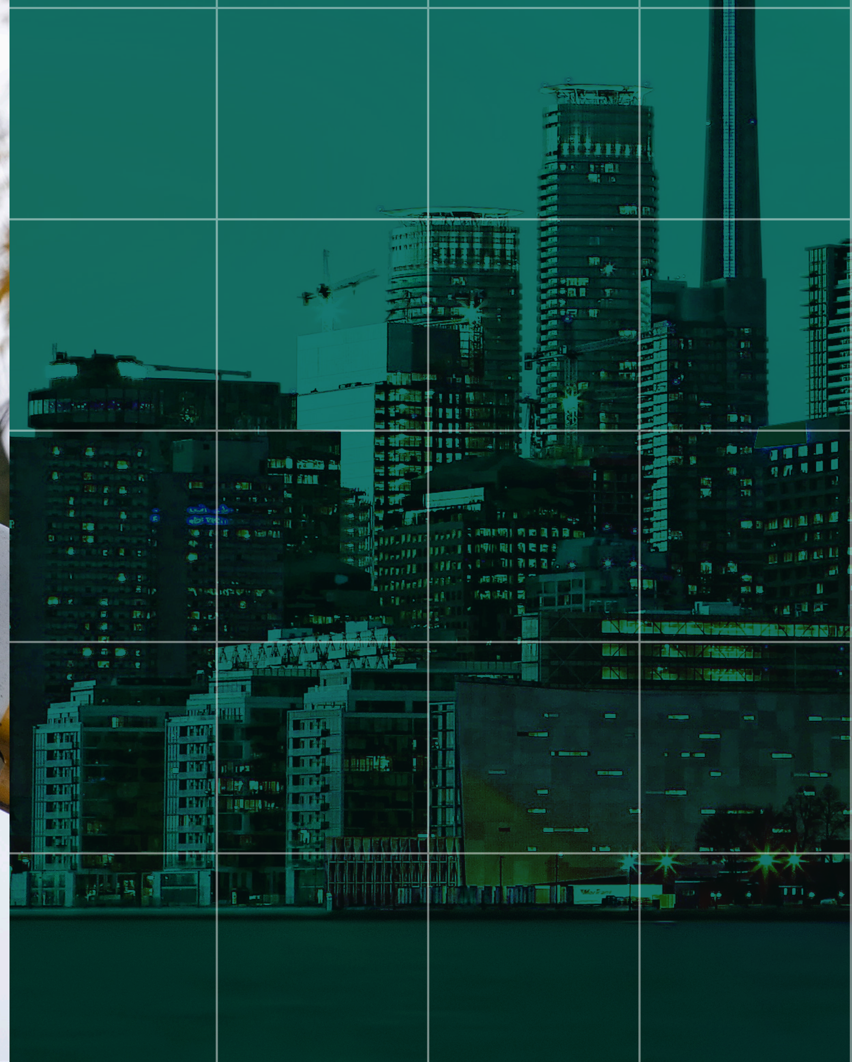
TORONTO HYDRO®

DISTRIBUTION SYSTEM PLAN

2025 – 2029



SERVICE AREA

18%
of the provincial demand

1,245[1]
employees

37
terminal stations

17,060[1]
primary switches

61,300[1]
distribution transformers

139
in-service municipal substations

15,393[1]
circuit kilometres of overhead wires

13,765[1]
circuit kilometres of underground wires

183,620[1]
poles

4
operation centres

1
control centre

790,000[1]
Total customers

707,178
Residential Service customers
(includes houses, apartments and condominiums)

82,820
General Service customers with monthly peak demand of less than 5,000 kW
(includes schools, restaurants and most shopping malls)

42
Large Users with monthly peak demand of 5,000 kW or greater[2]
(includes hospitals, universities and large manufacturers)

[1] Figures are approximate.

[2] Averaged over a 12-month period.

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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 2025-2029 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. In addition, this plan allows Toronto Hydro to meet the demands of a more dynamic environment driven by evolving customer preferences and increases in future customer demand due to an unprecedented energy transition.

Toronto Hydro is on track to successfully complete its previous plan for 2020-2024, with adjustments for typical changes and evolving circumstances, including the final rates approved by the Ontario Energy Board ("OEB") for that period. Due to the imposition of a 0.9 percent stretch-factor on Toronto Hydro's capital related revenue requirement, along with other drivers such as extraordinary inflation and increases in customer connections and load demand needs, the utility had to manage its 2020-2024 capital plan with a constrained level of funding relative to the needs and the costs of the plan. To do so, the utility reprioritized projects and adjusted program pacing as needed. Where possible, Toronto Hydro balanced the execution of the plan to deliver on high-priority objectives, and manage performance across numerous outcomes. Key objectives and outcomes included:

- Removing assets containing or at risk of containing PCB from the system by 2025 to comply with environmental obligations;
- Removing box construction framed poles from the system by 2026 to advance public and employee safety outcomes;
- Ensuring that the grid has sufficient capacity to serve areas of high-growth and development in the city and to connect customers in a timely and efficient manner;
- Installing monitoring and control equipment in areas like the network system to increase system observability and drive operational productivity;

- Replacing assets at a pace sufficient to maintain reliability with historical levels of performance and to maintain system health in line with 2017 condition; and
- Staying on track to complete the Copeland TS – Phase 2 project and the Control Operations Reinforcement program on time and within budget.

Despite the progress achieved during the 2020-2024 rate period, investing in the short-term performance and long-term viability of an aged, deteriorated, and highly utilized system, while preparing the system to meet the demands of increased electrification, remains a priority for the utility. 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, evolving energy needs driven by decarbonization efforts, increased electrification, the proliferation of Distributed Energy Resources ("DERs"), the digitalization of the economy, increasing technology and innovation are driving a more dynamic system that is transitioning away from the usual patterns of supply and demand. This is 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 2025-2029 DSP strikes a balance between these system needs and customer preferences, including:

- Price and reliability as top priorities, with reliability becoming increasingly important to residential customers, especially reducing the length of outages during extreme weather events;
- Expectations to invest in new technology to reduce costs and make the system better even if the benefits are not immediate, as long as the costs and benefits are clear; and
- Proactive investment in system capacity to ensure high growth areas do not experience a decrease in service levels.

The resulting five-year capital expenditure plan represents the minimum level of investment needed to confront the many and diverse challenges that the utility faces as a steward of the grid. Through an outcomes-oriented, customer-focused integrated planning process, this plan was designed to achieve balance between price and service quality performance both in the near-and longer-term, while readying the grid with least regrets investments to serve the needs of an increasingly electrified economy.

Toronto Hydro developed the DSP in full accordance with Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (2022), and in alignment with the principles and objectives of the OEB's *Renewed Regulatory Framework* ("RRF"), including the guidance in the OEB's Handbook for Utility Rate Applications (2016). In addition to the expenditure plan and forecast information for 2025-2029, the DSP provides historical and bridge year information for 2020-2022 and 2023-2024 respectively, including information on expenditures and accomplishments, material variances, and measured performance during the 2020-2024 plan period. In developing this DSP, Toronto Hydro built upon the experience of its last DSP (covering the 2020-2024 period) and the OEB's findings in the 2020 Custom IR Application, including refining successful elements (e.g. customer engagement, outcomes framework) and making substantial enhancements to certain fundamental elements (e.g. Asset Condition Assessment).

A2 DSP Organization

The 2025-2029 DSP consists of the following five major sections:

- **Section A – Distribution System Plan Overview:** Provides an overview of the key elements of the 2025-2029 DSP, including brief summaries of the 2025-2029 Capital Expenditure Plan and its drivers and outcomes; the Asset Management System including the principles, processes, and methodologies that underpin the plan; and the Customer Engagement results that informed the plan.
- **Section B – Coordinated Planning with Third Parties:** Provides an overview of how Toronto Hydro coordinates infrastructure planning with third parties, including information regarding broad regional planning efforts, and consultation with customers and telecommunication entities.
- **Section C – Performance Measurement for Continuous Improvement:** Provides an overview of Toronto Hydro's performance measurement framework and describes Toronto Hydro's historical reliability performance.
- **Section D – Asset Management Process:** Describes Toronto Hydro's asset management system, the current state of the assets and system performance challenges, and the utility's asset lifecycle optimization and risk management practices and methodologies. It also includes details on the utility's strategy to manage system capacity and modernize the grid effectively; as well as its Net Zero 2040 strategy.[1] The processes, tools, and information in this section were used to derive the 2025-2029 Capital Expenditure Plan.
- **Section E – Capital Expenditure Plan:** Describes how Toronto Hydro leveraged various substantive inputs – including Customer Engagement findings – to develop the 2025-2029 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.[2]

[1] These strategies are provided in Sections D4, D5, and D7 respectively.
[2] The vintage of asset data used within the DSP is primarily from year end 2022, unless noted otherwise, with the exception of the system peak load forecast, which was as of Oct, 2022.

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.

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

There are minor exceptions to the concordance between Chapter 5 and DSP headings as follows:

- With respect to requirements under section 5.2.3, Toronto Hydro does address reliability-related requirements within section C, but Service Quality Requirements ("SQR"), including OEB Appendix 2-G, are addressed outside the DSP within the utility's overall Historical Performance Results evidence at Exhibit 1B, Tab 3, Schedule 2. Toronto Hydro briefly discusses achievement of objectives for continuous improvement from the 2020-2024 DSP in section C, but provides amore detailed discussion in section E4 and Exhibit 1B, Tab 3, Schedule 2.
- Toronto Hydro addresses transmission or high voltage assets deemed as distribution assets (under section 5.3 of filing requirements) in Exhibit 2A, Tab 1, Schedule 1.
- Although touched on in section D4, the main narrative addressing "System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources" requirements under section 5.3 remains in the Capital Expenditure Plan section of the DSP (Section E3) for continuity with Toronto Hydro's 2020-2024 DSP structure.
- CDM Activities to Address System Needs under 5.3 are discussed at a high-level within section D (e.g. see D3.3.2.3, D4.2, or D5.2.2), and a more comprehensive discussion of these activities (i.e. demand response/flexibility services) and how they were integrated in planning is provided within the Non-Wires Solutions ("NWS") program evidence within the Capital Expenditure Plan (E7.2).

A3 System Challenges and Trends

This section provides an overview of the system and operational investment needs facing Toronto Hydro during the 2025-2029 forecast period. For a comprehensive discussion of Toronto's existing distribution system assets, configurations, climate, and utilization please refer to Section D2.

A3.1 Deteriorating and Obsolete Assets

Toronto Hydro owns and operates a mature distribution system. Despite its achievements in renewing the grid and improving reliability over the last decade, defective equipment continues to be a leading contributor to the duration of outages on the grid, representing approximately 40 percent of annual power interruptions experienced by customers based on duration (excluding Loss of Supply and Major Events).[3]

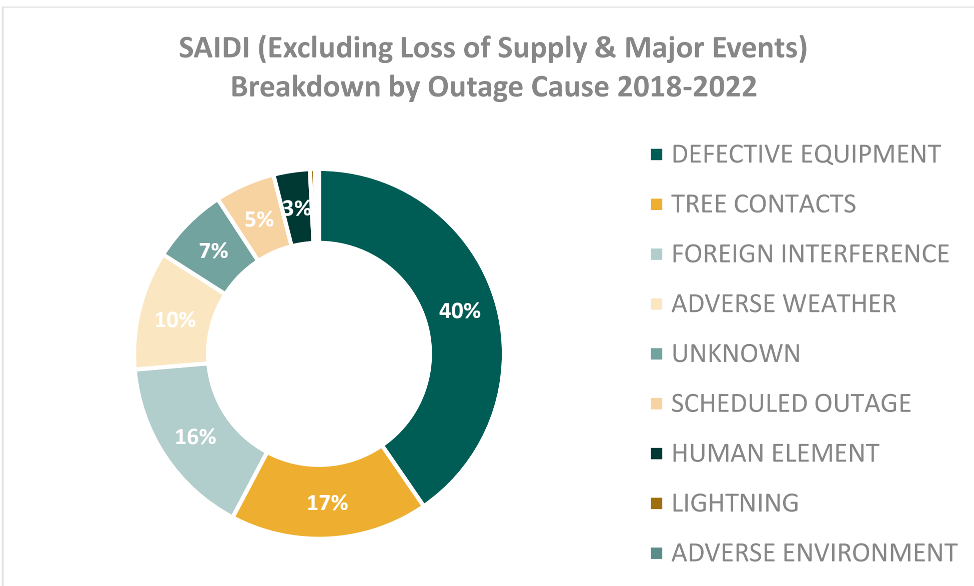

Figure 1: SAIDI (Excluding Loss of Supply & Major Events) Breakdown by Outage Cause 2018-2022

Toronto Hydro continues to face asset condition pressures across all parts of its system over the next rate period. The utility's Asset Condition Assessment ("ACA") demographic results, based on its Condition Based Risk Management ("CBRM") methodology, indicate substantial asset investment needs for a number of critical asset classes over the plan period. For Toronto Hydro's high-volume overhead and underground asset populations, the rate of asset deterioration expected by the end

[3] For more information on Toronto Hydro's historic reliability performance see Exhibit 2B, Section C

of the next rate period is projected to be roughly the same as it was in the equivalent analysis performed in 2018. While the rate of deterioration is somewhat lesser for network and stations assets, these smaller asset populations are still exhibiting significant projected deterioration and will require sustained investment to manage failure risks and other obsolescence-related risks (e.g. heightened risk of flood damage).[4]

In addition to asset condition, approximately a quarter of the utility's grid equipment continues to operate past useful life. An additional 11 percent is expected to reach that point by 2030, unless the utility invests in upkeeping system infrastructure in the 2025-2029 period.

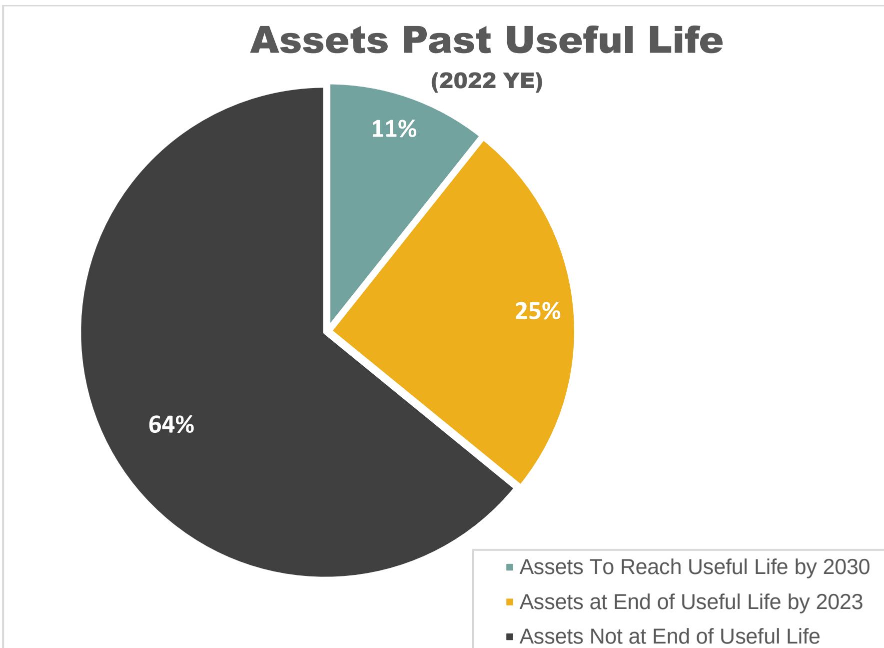

Figure 2: Percentage of Assets Past Useful Life

Allowing the number of assets past useful life, or in deteriorated condition, to grow increases the likelihood of power outages due to equipment failure, puts public and employee safety at risk, and leads to negative environmental outcomes. To manage these risks, Toronto Hydro must regularly inspect equipment to maintain its condition, or replace equipment that is in bad condition or performing poorly, before a failure occurs.[5]

[4] Refer to Exhibit 2B, Section E2.2.1.1 for an overview of asset condition demographics.
[5] Exhibit 2B, Section E2

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.

In light of the age, condition, and legacy asset risks discussed above, Toronto Hydro developed a risk-calibrated plan to invest the minimum required to prevent a decline in reliability over the short- and long-term while investing to reduce potentially significant impacts for customers in areas served by legacy assets such as direct-buried cable and rear-lot plant.

A3.2 Complex Operating Conditions

Toronto Hydro operates in a complex urban environment based on the dense nature of the city's population, the age of the city's infrastructure, and the nature of its customer base. These each pose material challenges in the utility's day-to-day operations.

Toronto is an urban service territory with a population density of 4,428 people per kilometer.[6] Table 2 below compares Toronto's population density with the five largest cities in Ontario:

Table 2: Ontario Cities Population Density[7]

Ontario's 5 Largest Cities by Population	Population (People)	Land Mass (km^2)	Population Density (People/km)
Toronto	2,794,356	631.1	4,428
Ottawa	1,017,449	2788.2	365
Mississauga	717,961	292.74	2,453
Brampton	656,480	265.89	2,469
Hamilton	569,353	1118.31	509

Based on Census Subdivision data from 2021 Census

[6] The City of Toronto is home to approximately three million people within a land mass of 631.1km per Statistics Canada, Canada's Large Urban Centres Continue to Grow and Spread (February 9, 2022) https://www150.statcan.gc.ca/n1/daily-quotidien/220209/dq220209b-eng.htm; Statistics Canada, Defining Canada's Downtown Neighbourhoods: 2016 Boundaries (May 11, 2021)
[7] Statistics Canada, Table 98-10-0002-01 Population and dwelling counts: Canada and census subdivisions (municipalities) https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=9810000201

The density of Toronto Hydro's service territory is unique even within an international context due to the ever-increasing number of high-rise buildings. As seen in Table 3 below, New York City is the only urban centre in the world with more high-rise buildings than Toronto:

Table 3: International Cities High-Rise Buildings[8]

Rank	City	Country	Highrise Buildings
1	New York City	United States	6,223
2	**Toronto**	**Canada**	**2,598**
3	Seoul	South Korea	2,578
4	Dubai	United Arab Emirates	2,360
5	Hong Kong	China	1,916
6	Tokyo	Japan	1,533
7	Busan	South Korea	1,311
8	Kyiv	Ukraine	1,275
9	Chicago	United States	1,247
10	Shanghai	China	1,236

As a dense and old city by North American standards, Toronto also suffers from a challenging combination of legacy standards, limited availably of rights of way for locating distribution equipment, underground congestion which drives a need for increased co-ordination with other utility providers (e.g. water, transit, natural gas, telecommunications), complex permitting and approval processes, longer drive times due to traffic congestion, limitations on the size and scale of distribution assets, and disruptions related to large-scale local events. All of these considerations translate into significant planning and coordination requirements, adding both time and costs to system maintenance, renewal and enhancement investments.[9]

Beyond challenges created by service territory, density and asset vintage, the unique customer base in the downtown core places additional weight on Toronto Hydro's responsibility as a system operator. This customer composition – which includes major hospitals, the provincial legislature, and headquarters of banks, businesses and other critical financial institutions – necessitates elevated requirements for reliability and continuity of service to customers whose operations are critical to

[8] Highrise building categorized as a multi-floor building at least 12 stories or 35m in height. As per data from SkyscraperPage, Global Cities & Buildings Database https://skyscraperpage.com/cities/#notes
[9] Exhibit 1B, Tab 3, Schedule 3

the sound functioning of the provincial and federal economy. As a result, Toronto Hydro's downtown system is designed and operated with a high-level of redundancy, which in turn requires that additional prudent costs be incurred.[10]

A3.3 A Growing City

The population of Toronto is also increasing and expected to grow by approximately 23.8 percent between 2021 and 2031, a marked increase from the 6.8 percent growth over the prior decade (from 2011 to 2021).[11] The growth is concentrated in certain pockets, namely the downtown core and along the transit corridors, and is oriented vertically with a continuing trend of high-rise developments. This has resulted is a marked need for new housing, transit solutions, and infrastructure, all of which needs to be serviced by Toronto Hydro in the years to come.[12]

This growth is underscored by the fact that Toronto has led the North American crane count since 2015 by a margin that is almost equivalent to the rest of the cities combined.[13]

[10] Ibid
[11] City of Toronto, Toronto's Population Health Profile (February 2023) https://www.toronto.ca/wp-content/uploads/2023/02/940f-Torontos-Population-Health-Profile-2023.pdf
[12] Exhibit 2B, Section D2
[13] Urbanize Toronto, RLB Crane Index Records 238 Cranes in Toronto During Q1 2023 (April 15, 2023) https://toronto.urbanize.city/post/rlb-crane-index-records-238-cranes-toronto-during-q1-2023#:~:text=According%20to%20the%20latest%20report,%2C%20Chicago%20(14)%2C%20Honolulu

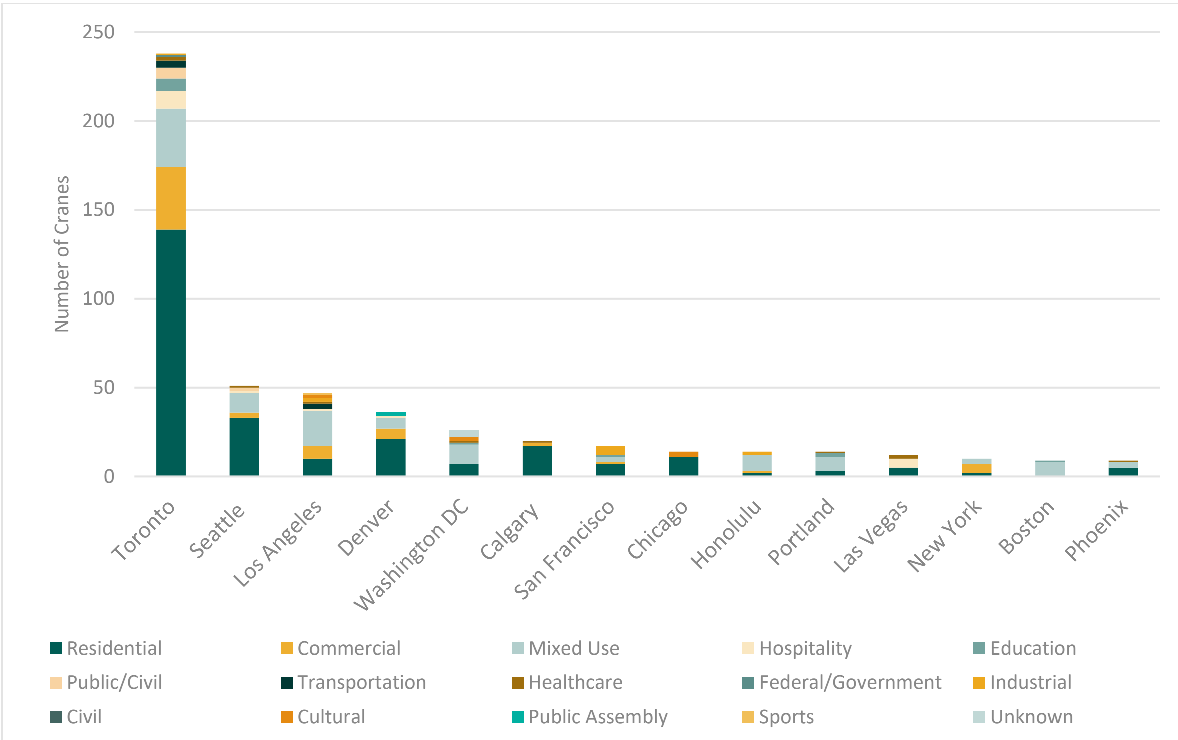

Figure 3: RLB Crane Index - Q1 2023

In addition to high-rise buildings, this growth is also driving the development of new housing communities through the redevelopment of areas such as Downsview, the Golden Mile and the Port Lands, some of which are planned as net zero communities and to meet the highest performance measures of the Toronto Green Standard.[14]

The significant expansion of transit networks is also needed to support this population growth and there are numerous new projects under construction in the city including the Yonge North Subway Extension, Finch West LRT, Scarborough Subway Extension, Eglington Crosstown LRT, Eglinton Crosstown West Extension, and the Ontario Line.[15]

Finally, this growth is also putting additional stress on the system through the incremental loads associated with technology and digitalization. In addition to organic growth, Toronto has become

[14] Exhibit 2B, Section D4
[15] Exhibit 2B, Section E5.2

Canada's largest data center market, with 107 MVA of incremental demand load connected during the 2020-2024 period and 207 MVA forecasted to come online from 2025-2029.[16]

A3.4 Climate Change and Adverse 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 110 times per year as opposed to 87 times per year currently.[17] 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. These extreme events can cause major disruptions to Toronto Hydro's distribution system.

Extreme weather amplifies the challenge of distributing electricity to a mature, dense, and rapidly growing urban city. Heat, high winds, heavy rainfall, freezing rain, and heavy snowfall can cause major system damage and result in prolonged power outages. As evidenced by recent events outlined in Table 4 below, extreme weather has become a regular operating condition that the utility must consider and manage in its day-to-day operations and long-term planning activities. With the frequency and intensity of adverse weather increasing due to climate change, Toronto Hydro's grid and operations must become more resilient to this challenge.

Table 4: Extreme Weather (January 2020 through May 2022)

Event	Description of Impact
High Winds Storm (May 2022)	• 142,052 Customers impacted at its peak • 5 days to restore power to all customers
Flash Storm (August 2021)	• 20,000 customers impacted at peak • 2 days to restore power to impacted customers
Thunderstorm High Volume Event (July 2021)	• A line of thunderstorms with windspeeds in excess of 75 km/h. • 12,000 customers were impacted at its peak • Service restored for the majority of customers within 2 days
High Wind Event (April 2021)	• Wind expected to reach ~95hm/hr • 22,000 customers impacted at its peak • 1 day to restore power to impacted customers

[16] Exhibit 2B, Section E5.1
[17] Toronto Hydro engaged Stantec to update its Climate Change Vulnerability Assessment, which is filed at Exhibit 2B, Section D2, Appendix A.

Event	Description of Impact
High Wind Event (November 2020)	• Winds in excess of 100 km/h • Estimated 8000 customers impacted and 101 outages at its peak
Flash Storm (July 2020)	• Approximately 50-70mm of rain • 50,000 customers impacted at peak • Impacted customers restored within 2 days
Adverse Weather (January 2020)	• Approximately 60mm of rain, 5-15mm of ice and 90 km/h winds • 4900 customers impacted at its peak • Impacted customers restored within 3 days

Adverse weather affects the distribution system in different ways. The underground system is vulnerable to flooding from extreme rainfall, while the overhead system is susceptible to extreme winds, freezing rain, and wet snow, resulting in damage and outages. Broken trees and the weight of ice and snow accretions can bring lines, poles, and associated equipment to the ground. For instance, in May 2022, an extreme wind event known as the Derecho Storm struck Southern Ontario and Quebec with 120+km/h winds. These extreme winds caused substantial damage to vegetation, which in turn damaged overhead distribution wires and equipment leaving approximately 142,000 customers (18 percent of Toronto Hydro's total customer base) without power at the peak of the storm. While the majority of customers were restored within 48 hours, it took approximately 5 days and cost approximately $2.35 million to restore power to all customers.[18]

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. Weather conditions of high heat, high winds, heavy rainfall, 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, but trends from the past 25 years suggest that these changes are already affecting the system. Figure 4 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 25 years. In both cases it is observed that there is an increasing trendline over the period. With respect to high wind days, an even steeper increase has been observed, and seven

[18] Exhibit 2B, Section D2

of the 10 years with the greatest number of days of wind gusts above 70 kilometres per hour have occurred in the last 10 years (these years are highlighted in orange).

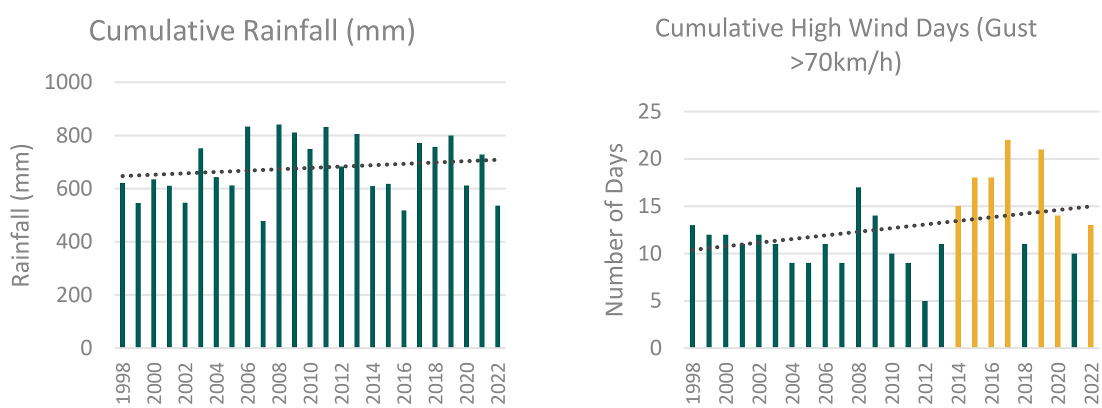

Figure 4: Cumulative Rainfall (left) and Number of High Wind Days (right) in Toronto[19]

These trends are expected to continue through the 2030s and 2050s with the frequency of extreme rainfall events of 100 mm in less than 1-day antecedent increasing by 11 percent and 20 percent respectively. In terms of high winds, climate projections show that 10-year wind speeds are to increase by 0.7 percent and 2.7 percent in the 2030s and 2050s respectively.[20]

These weather trends have increased reliability risks for the distribution system. Toronto Hydro analyzed system reliability data to understand the correlation between wind speed above 70 kilometres per hour, the number of forced outages on the overhead system, and SAIDI performance. This revealed a high correlation between wind speed above 70 kilometres per hour and the number of forced outages on the overhead system. It was also determined that higher wind speeds were correlated with increased SAIDI.

Toronto Hydro has recognized that existing codes, standards, and regulations with regard to historical weather data do not always account for ongoing and future changes to climate. To address this, Toronto Hydro now incorporates climate data projections into its equipment specifications and station load forecasting. In 2016, Toronto Hydro updated its major equipment specifications to adapt

[19] Government of Canada, Weather, Climate and Hazard Historical Data, http://climate.weather.gc.ca/historical_data/search_historic_data_e.html
Weather data compiled using Toronto Lester B. Pearson INTL A for January 1998 to June 2013 and Toronto INTL A for July 2013 to December 2022.
[20] *Supra* note 16.

to climate change, such as using stainless steel construction for submersible transformers and replacing air-vented, padmounted switches with more robust designs. As part of the ongoing efforts, Toronto Hydro has planned various activities between 2025 and 2029, including reconfiguring feeders and relocating assets away from the ravines in the Overhead System Renewal program, replacing submersible transformers, and implementing flood mitigation systems at vulnerable stations.

In addition to these system hardening measures, Toronto Hydro's Grid Modernization Strategy for 2025-2029 has been developed in part to improve long-term system reliability and resiliency in the face of external pressures from both future increases in system utilization and evolving climate impacts. For more information on the Grid Modernization Strategy, please refer to Exhibit 2B, Section D5.

A3.5 Technology Advancement

Technology and innovation are also driving the need for a more dynamic system that is transitioning away from usual patterns of supply and demand towards more complex interactions and inputs in electricity generated and consumed. The role of the utility continues to evolve to support the new smart grid ecosystem, comprising renewable and other distributed energy resources (DER), such as electric vehicles, solar panels, and battery energy storage systems.

Customers are showing a continued interest in participating in the electricity system as both consumers and producers of power. DER connections have grown in recent years as result of government policies and declining costs of technologies such as solar panels. By the end of the decade, Toronto Hydro expects to have over 4,400 DER connection projects representing a total installed capacity of approximately 517 MW, an increase of approximately 67 percent compared to 2022.[21]

Integrating DERs into the grid provides customers more tools to actively manage their energy needs, and enables the grid to be supplied by locally-generated renewable electricity resources. To advance these outcomes, Toronto Hydro must address the significant challenge of accommodating electrons that flow bi-directionally within a grid that was not built for this type of supply and demand. Equipment that has a high number of DER connections is more likely to experience unstable conditions that pose significant reliability and safety risks to the system and its users. Toronto Hydro

[21] Exhibit 2B, Section E5.1

monitors all DER connections closely for these factors to ensure that the grid remains safe and reliable for all customers, and is building advanced grid capabilities to mitigate against these risks and enable efficient DER adoption by customers in the future.[22]

Technological advancement also poses the challenge of managing a heightened risk of digital security threats, as cyber-crime intensifies across Canada due to changing geopolitical dynamics. While smart grid systems, infrastructure automation, and other technological advancements being used by the utility and its customers offer many benefits, they also increase the exposure of the grid and those connected to it to greater risk of attack by hostile actors. This intensifying global challenge is particularly acute in major economic centers such as Toronto. Electric utilities are targets for security breaches because of the critical role they play in enabling essential service providers (e.g. hospitals, public transit, water treatment systems, communications, and traffic management) and the databases of confidential customer information they possess.[23]

Toronto Hydro needs to prepare itself to assist customers in taking advantage of technological innovation and advancements, while also protecting itself and its customers from the risks they introduce.

[22] Exhibit 2B, Section A
[23] Exhibit 2B, Section D8; Exhibit 2B, Section E8.4

A4 Development of the 2025-2029 DSP

A4.1 Business Planning & Customer Engagement

In developing a multi-year investment plan, Toronto Hydro begins from the principle that the utility is entrusted by customers and stakeholders to prepare a responsible plan that balances both price and service quality outcomes. The 2025-2029 Plan achieved that balance through an integrated and iterative business planning process that considered customer feedback from start to finish.

Toronto Hydro's 2025-2029 DSP, including the 2025-2029 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 system ("AMS") 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 5, below.

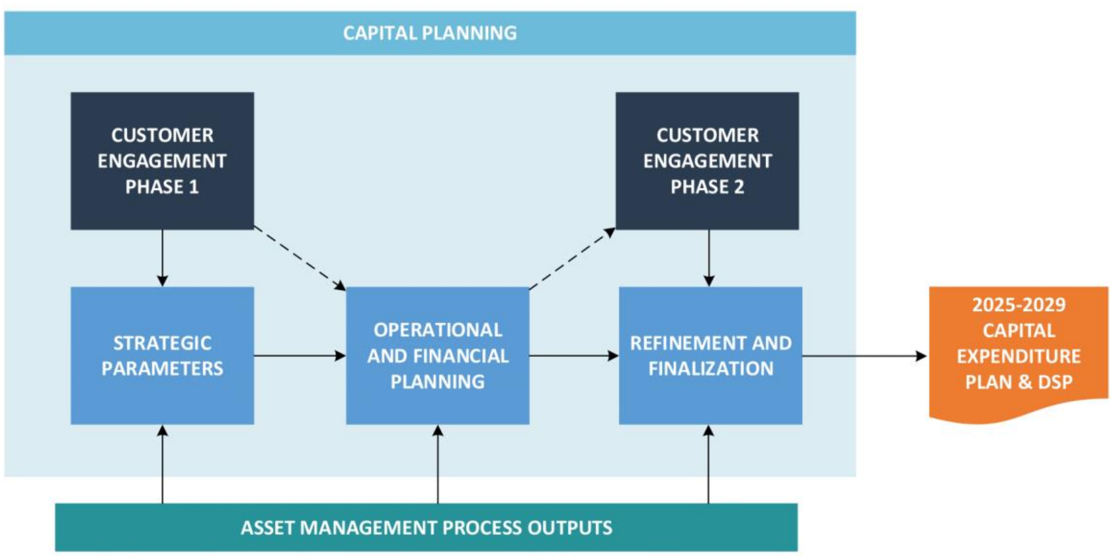

Figure 5: Capital Planning in Business Planning

Toronto Hydro began planning by engaging customers to ascertain their needs and priorities for the 2025-2029 planning period (i.e. Phase 1 of Customer Engagement), and used the customer feedback received to provide strategic direction to the planning process.

The common themes of customer priorities centered around the following:

1. **Price and reliability are the top customer priorities:** Relative to price, reliability has become increasingly important to residential customers. When it comes to reliability, customers prioritize reducing the length of outages, with a particular focus on extreme weather events for residential and small business customers. Key Account customer are more sensitive to power interruptions and prioritize reducing the total number outages.
2. **New Technology:** Almost equally to price and reliability, customers expect the utility to invest in new technology that will reduce costs and make the system better, even if the benefits aren't immediate, as along as the costs and benefits are clear.
3. **System Capacity:** Customers expect Toronto Hydro to invest proactively in system capacity to ensure that high growth areas do not experience a decrease in service levels. The majority of Key Account customers surveyed have Net Zero goals to reduce their business' net greenhouse gas emissions to zero—and expect Toronto Hydro to support them in meeting their climate action objectives by ensuring that the system has capacity for growth and by providing them advisory services.

With consideration for customers' needs, priorities and other inputs, Toronto Hydro organized its plan around the following investment priorities.

1) **Sustainment and Stewardship:** Risk-based investments in the renewal of aging, deteriorating and obsolete distribution equipment to maintain the foundations of a safe and reliable gird.
2) **Modernization:** Developing advanced technological and operational capabilities that enhance value and make the system better and more efficient over time.
3) **Growth & City Electrification:** Necessary investments to connect customers (including Distributed Energy Resources ("DERs") and build the capacity to serve a growing and electrified local economy.
4) **General Plant:** Investments in vehicles, work centers and information technology ("IT") infrastructure to keep the business running and reduce Toronto Hydro's greenhouse gas emissions.

For each of these strategic priorities, Toronto Hydro set performance objectives that provide value for customers and are meaningful to its operations.

1 **Table 5: 2025-2029 Performance Objectives**

Investment Priority	Key Performance Objectives
Sustainment and Stewardship	• Maintain recent historical system reliability • Manage asset risk by maintaining overall health demographics of the asset population in 2025-2029 • Adhere to previous commitments for safety and environmental compliance activities (e.g. removal of at-risk PCBs by 2025; complete Box Conversion by 2026) • Optimize the pace of renewal investment from year-to-year using risk-based decision-making tools. • Ensure investment pacing contributes to stable long-term investment requirements for all assets (2030+)
Modernization	• Prioritize investments that will deliver demonstrable benefits to customers, especially enhancements that will improve value-for-money in the long-term (i.e. efficiency) • Improve system reliability through enhanced fault management, leveraging automation and advanced metering through Advanced Metering Infrastructure ("AMI") 2.0 • Enhance system observability across the system, enabling better asset management and operational decision making • Leverage technology to improve customer experience (e.g. reliability, power quality, customer tools, DER integration) • Enhance resiliency and security of the system through advanced grids, targeted undergrounding of critical overhead assets, and enhancements to distribution schemes for critical loads downtown
Growth & City Electrification	• Connect customers efficiently and with consideration for an increase in connections volumes due to electrification • Expand stations capacity to alleviate future load constraints, with consideration for increased EV uptake, decarbonization drivers, and other growth factors (digitization and redevelopment) • Optimize near-term system capacity through load transfers, bus balancing, cable upgrades and the targeted use of non-wires solutions such as demand response and energy efficiency • Alleviate constraints on restricted feeders to accommodate the proliferation of DER connections • Install control and monitoring capabilities for all generators > 50kW • Accommodate relocations for committed third-party developments, including priority transit projects

Investment Priority	Key Performance Objectives
General Plant	• Replace critical facilities assets in poor condition • Improve stations site conditions and physical security to meet legislative requirements (Ontario's Building Code,[24] *Occupational Health and Safety Act,*[25] CSF, etc.) • Achieve emissions reduction by implementing Toronto Hydro's NZ40 strategy • Support modernization objectives including grid automation and customer experience. • Minimize cybersecurity risks associated with IT/OT infrastructure • Ensure IT infrastructure is available and reliable with minimal service disruption

To ensure that price was kept top-of-mind, the utility also adopted top-down financial constraints for the development of the plan:

1. **Price Limit:** Toronto Hydro set an upper limit of approximately 7 percent as a cap on the average annual increase to distribution rates and charges.[26]
2. **Budget Limits**: Toronto Hydro set upper limits of $4,000 million for the capital plan and $1,900 million for the operational plan over the 2025-2029 period.

In developing these strategic parameters, Toronto Hydro considered a number of inputs including but not limited to:[27]

- customer priorities and preferences identified in Phase 1 of the utility's planning-specific Customer Engagement activities;
- historical and forecast system health demographics and performance;
- long term asset stewardship needs;
- forecasted system use profiles and pressures;
- safety and environmental risks; etc.

Based on the aforementioned inputs, through an iterative process that spanned over a year, Toronto Hydro system planners and experts worked diligently to identify the minimum investments necessary to meet these objectives and balance near-and long-term service quality performance with price

[24] Ontario Regulation 332/12: Building Code, under Building Code Act, 1992, S.O. 1992, c. 23.
[25] *Occupational Health and Safety Act,* RSO 1990, c. O.1
[26] As calculated for the monthly bill of a Residential customer using 750 kWh.
[27] For a more exhaustive list, please refer to Exhibit 2B, Section E2.1.1.

impacts for customers, as informed by the feedback in Phase 1. Toronto Hydro selected the $4,000 million capital budget limit to achieve this balance of keeping rates reasonable without compromising performance.

These parameters guided the operational and financial planning activities that produced the Capital Expenditure Plan for 2025-2029. 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 performance objectives, while remaining within the financial constraints established for the 2025-2029 period. This exercise led to a $480 million reduction between the initial plan proposals and the draft plan, as described in Section E2.

Toronto Hydro's consultant Innovative presented the draft plan to customers in the Phase 2 customer engagement to solicit feedback on (i) pacing and bill impacts for key investments areas in Toronto Hydro's plan; and (ii) the price of the overall draft plan and whether customers are willing to accept it. Overall, a majority (84 percent) of customers in all customer classes supported the price increase associated with the draft plan or an accelerated version of it.

Overall, Toronto Hydro reprioritized investments to produce an optimized and customer-aligned capital expenditure plan of $4 billion over the 2025-2029 period.[28] The program outcomes in Sections E5 through E8, as well as the 2025-2029 Performance Outcomes for the plan as whole (discussed in Exhibit 1B, Tab 3, Schedule 1 and Exhibit 2B, Section E2 respectively), have been developed and calibrated to reflect customer feedback, ensuring the performance and accomplishments of the DSP are tracked over the 2025-2029 period in relation to outcomes that are meaningful to customers.

These investment priorities are driven by critical needs that, if not adequately addressed, could impair Toronto Hydro's ability to deliver the outcomes that customers value. In some cases, these risks will materialize in the near term, such as lack of capacity to support urban intensification and economic development. However, in many cases, the risks will materialize in the medium to long term as the grid becomes more heavily-utilized and more susceptible to longer and more frequent outages that are complex and costly to resolve. Toronto Hydro must invest in the priorities described below to manage these risks.

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

A4.2 Asset Management Process and Enhancements

Toronto Hydro's distribution system AM Process is explained in detail in Section D and is generally aligned with the AM Process described in the 2020-2024 DSP, with some enhancements as discussed below. The objective of Toronto Hydro's AMS 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.

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 AMS over the 2020-2024 period are highlighted in Figure 6 below. For more information on these improvements, please refer to Section D of the DSP.

As highlighted in Figure 6 and Section D1.3, Toronto Hydro has an extensive track record of continuous improvement in asset management. Looking ahead, the utility recognizes that the coming acceleration in decarbonization, digitalization (e.g. automation), and decentralization (i.e. two-way energy flows) within the energy economy will result in much greater asset management complexity and a more urgent need for adaptive flexibility within the utility's management systems. The utility believes that success in this more complex environment will depend in large part on having a strong management foundation in the form of a rigorous and comprehensive AMS that consistently tracks toward industry best practices.

With this context in mind, Toronto Hydro is committing to aligning its AMS to the ISO 55001 standard for asset management, with the goal of achieving certification within the 2025-2029 rate period. ISO 55001 was developed by the International Organization for Standardization and is the most recognized standard for asset management globally. It provides terminology, requirements and guidance for establishing, implementing, maintaining and improving an effective asset management system, and represents a global consensus on asset management and how it can increase the value generated by organizations like Toronto Hydro.

Fundamental to the ISO 55001 framework are the concepts of strategic alignment, risk-based decision-making and continuous improvement. By pursuing certification, Toronto Hydro is volunteering to be held accountable through independent audits for the continuous improvement of its AMS and the maturation of its risk-based decision-making frameworks. The utility believes that the effort of pursuing certification will provide the additional rigor and discipline required to deliver greater value and performance, including greater cost-efficiency, as customer and stakeholder needs rapidly evolve and operating challenges become more intense (e.g. climate risk).

To streamline Toronto Hydro's asset management process, the utility is also embarking on a transformative project to implement an Engineering Asset Investment Planning ("EAIP") solution to support investment planning and project development activities. This strategic initiative is poised to elevate Toronto Hydro's annual project portfolio and long-term asset investment strategies, while simultaneously revitalizing asset management methodologies and simplifying the scope formulation procedures. As part of its multi-year efforts to adopt the EAIP solution, Toronto Hydro is developing a custom and robust value framework to evaluate relative value of its investments, leading to more well-informed and strategic asset management decisions as discussed in Section D3 of the DSP.

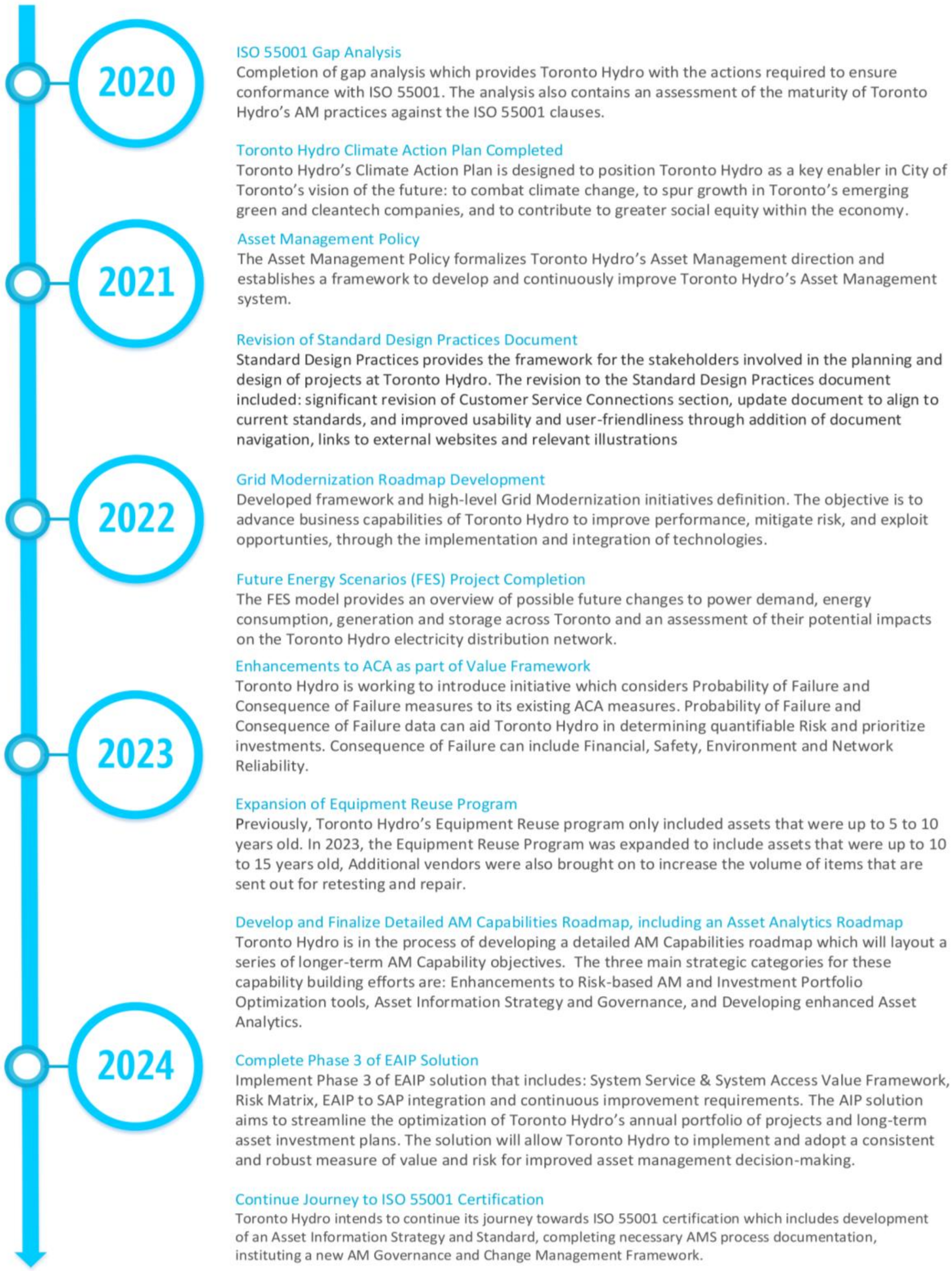

Figure 6: Recent Enhancements of the AM Process (2020-2024)

In addition to the distribution system AMS, Toronto Hydro has similarly robust AM processes for its facilities, fleet, and IT assets. The AM approach for facilities and IT are summarized in Sections D6 to D8, while the AM strategy for fleet can found in the Fleet and Equipment Services program in Section E8.3.

A5 Investment Priorities

A5.1 Sustainment & Stewardship

Sustainment investments to renew aging and deteriorating infrastructure and standardize outdated equipment continue to be the largest part of the 2025-2029 Investment Plan. These investments must be made to maintain system performance, mitigate reliability, safety, and environmental risks, and enhance the grid's capability to serve electrified technologies such as electric vehicles, solar panels, energy storage batteries, and electric heat pumps and boilers.

Past investments in the grid and operations have resulted in improvements in reliability, safety and environmental outcomes – the average duration of outages customers experience now compared to a decade ago was reduced by 26 percent over the last decade, the injury rate for employees has decreased by 60 percent, oil spills have been avoided, and the utility is on track to eliminate at risk PCB transformer from its system by 2025.[29,30] Investing in the performance and long-term stewardship of an aging, deteriorated, and more highly-utilized system remains an urgent priority for the utility, alongside getting the grid ready to serve Toronto's growing electricity needs.

System health is a leading indicator of a safe and reliable grid. Allowing system health metrics – age and condition – to deteriorate would lead to the gradual but steady degradation of system performance. As an example, underground cables are the largest contributor to defective equipment outages and continue to present significant demographic challenges in the coming years with approximately 73 percent of direct buried cables in the horseshoe area expected to be past their serviceable life by the end 2022.[31] Proactive investment in the replacement of these assets is a key part of sustaining the short and long-term performance of the grid.

[29] Exhibit 1B, Tab 3, Schedule 2
[30] Exhibit 4, Tab 4, Schedule 1
[31] Exhibit 2B, Section E6.2

Recognizing that customers are generally satisfied with current levels of reliability, and expect the utility to invest in new technology for the future,[32] Toronto Hydro right-sized the sustainment objectives of the Investment Plan to maintain (rather than improve) the overall health of the grid over the 2025-2029 period. Maintaining system health metrics is necessary to sustain grid performance and prevent the accumulation of a backlog of equipment at risk of failure, or otherwise needing to be upgraded. Renewal investment backlogs are problematic not only because they greatly heighten system reliability risk: they also result in rate instability for customers, as well as high-inefficiencies in work execution. Such inefficiencies stem in part from performing more work reactively – which is typically higher cost – and in part because planned work becomes more expensive due to surges in material and labour needs that could otherwise be smoothed out through paced proactive investment.[33]

Keeping pace on renewal is also important for hardening the grid against more frequent extreme weather events, and standardizing outdated equipment that poses barriers to electrification. For example, legacy 4 kilovolt stations and feeder equipment, restricts the connection of large electrified loads and distributed energy resources. To prepare the grid for electrification these assets must be gradually converted to new standards, and that work is being done in a paced way through sustainment investments that also deliver safety, reliability and environmental outcomes.[34]

Table 6 below provides a summary of Toronto Hydro's sustainment capital programs:

Table 6: Sustainment Capital Programs

Capital Program/Segment	Investment ($ Millions)
Area Conversions[35]	**$237**
Underground Renewal – Horseshoe[36]	**$476**
Underground Renewal – Downtown[37]	**$165**
Network System Renewal[38]	**$123**

[32] Exhibit 1B, Tab 5, Schedule 1, Appendix A
[33] Exhibit 2B, Section E2
[34] *Ibid.*
[35] Exhibit 2B, Section E6.1
[36] Exhibit 2B, Section E6.2
[37] Exhibit 2B, Section E6.3
[38] Exhibit 2B, Section E6.4

Capital Program/Segment	Investment ($ Millions)
Overhead Renewal[39]	**$273**
Stations Renewal[40]	**$218**
Reactive and Corrective Capital[41]	**$328**
Sustainment Capital	**$1,820**

A5.2 Growth and City Electrification

The obligation to serve customers who want to connect to the grid is at the heart of Toronto Hydro's mandate as an electricity distributor. What accompanies that core obligation is the responsibility to make reasonable investments to prepare for future growth. This responsibility is more important than ever, as customers, communities and governments at all levels are actively embarking on an unprecedented transformation of the energy system to mitigate the worst impacts of climate change.

It is clear from studies that have been done locally, provincially, and internationally that decarbonization-through-electrification imperatives are expected to drive demand for electricity in the next two decades. Experts indicate that demand could increase up to 2 to 3 times depending on the range of technologies and policy tools that are adopted.[42]

The particular drivers of demand are subject to dynamic forces of technological advancement, public policy imperatives and consumer behaviour. As an example, the decarbonization of existing housing

[39] Exhibit 2B, Section E6.5

[40] Exhibit 2B, Section E6.6 – includes HONI Switchgear renewal costs of $29M.

[41] Exhibit 2B, Section E6.7

[42] Toronto Hydro's own Future Energy Scenarios forecast a doubling in Toronto's electricity demand by the year 2050 across multiple scenarios (for more information please refer to Exhibit 2B – Section D4, Appendix A). The IESO's Pathways to Decarbonization report forecasts that demand could more than double by 2050 (https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization), while Enbridge's Pathways to Net Zero forecasts an increase in demand of over three times in its electrification scenario (https://www.enbridgegas.com/en/sustainability/pathway-to-net-zero). In the US, utilities such as National Grid (https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan-sept2023.pdf), Eversource (https://www.mass.gov/doc/gmacesmp-drafteversource/download?_gl=1%2Ako8zfs%2A_ga%2ANzUwNDI5MDE3LjE2NTA5ODEyMjQ.%2A_ga_SW2TVH2WBY%2AMTY5MzkyMDE2OS4zNi4xLjE2OTM5MjM1NzQuMC4wLjA.), and Unitil (https://unitil.com/ma-esmp/en) all published modernization plans forecasting demand increases of over 2 times by 2050. ISO New England also completed a study which forecasts a doubling in system peak by 2050 (https://www.iso-ne.com/static-assets/documents/100004/a05_2023_10_19_pspc_2050_study_pac.pdf). National Grid ESO (Great Britain's system operator), also forecasts in an increase of about 2 times across many of its future energy scenarios (https://www.nationalgrideso.com/document/283101/download).

and industrial buildings remains a policy puzzle, and a number of options are being considered to find suitable paths.[43] To manage this uncertainty and the cost-consequences for customers, the utility must be measured-but-proactive in its investment plan (as both asset and human capital investments are long lead-time), and must be deliberate in sustaining and modernizing its grid and operations to ensure that it is ready to serve and enable customer choice in all scenarios.

As outlined above, Toronto Hydro has embraced this uncertainty by prioritizing investments that can provide value under all scenarios under the "least regrets" approach. This enables the utility to meet emerging challenges without having to wait for all unknown variables to stabilize. Based on its least regrets investment philosophy, the 2025-2029 Investment Plan accommodates an increase of 23 percent in system peak demand, which includes electrification of transportation (EVs) across residential, industrial and commercial sectors, as well as major transit projects like the Ontario Line and Scarborough Subway Extension, and redevelopment plans for the Downsview, The Port Lands and Green Mile communities.[44]

The 2025-2029 Investment Plan anticipates a material increase to the customer connection portfolio (consistent with the trend observed in recent years) and expands stations capacity to alleviate future load constraints due to growth resulting from EV uptake, digitalization of the economy (e.g. data centers and digital transformations of existing sectors), and city growth and redevelopment (e.g. urban densification and transit expansion). The 2025-2029 Investment Plan also optimizes near-term system capacity through active management measures such as load transfers and balancing, equipment upgrades, and the targeted use of non-wires solutions – both demand-side measures that leverage customer DERs as well as grid-side technologies such as renewable enabling energy storage systems.[45]

By the end of this decade, DER capacity is expected to increase by approximately 67 percent.[46] Getting these resources safely connected to the grid is necessary to enable greater choice and support customers in achieving their electrification objectives (e.g. ESG, net zero, environmental conscientiousness, home/business resiliency). Moreover, integrating these resources into the system is critical to right-sizing system expansion investments, and developing a grid that is more

[43] City of Toronto, Net Zero Existing Buildings Strategy https://www.toronto.ca/wp-content/uploads/2021/10/907c-Net-Zero-Existing-Buildings-Strategy-2021.pdf
[44] Exhibit 2B, Section D4
[45] Exhibit 2B, Section D4
[46] Exhibit 2B, Section E5.1

resilient in the future as a result of greater levels of local power supply. To accommodate increasing volumes of connections in this area, the 2025-2029 Investment Plan ensures control and monitoring capabilities for all distributed generation and addresses constraints on restricted feeders through traditional investments such as station bus-ties and alternative technologies such as energy storage.[47]

While there is certainty that fundamental change is ahead, there are still degrees of uncertainty about how that change will unfold. For example, government incentives or market evolution could further accelerate customer adoption of electric vehicles or other fuel switching technologies. Similarly, provincial procurement programs could create expanded role for DERs in the deployment of coordinated infrastructure solutions to meet Ontario's energy needs.[48] As a result of such external factors, the pacing and level of certain demand-driven expenditures and revenues can change and materially deviate from the forecast. To that end, Toronto Hydro proposes a flexibility mechanism (known as a variance account) to reconcile differences between forecasted and actual demand-driven costs and revenues. During a time of unprecedented change and transformation in the economy and energy system, it is key to protect both ratepayers and the utility from structural unknowns that could have a material impact on the plan.[49]

Table 7 below outlines the programs that enable growth and city electrification:

Table 7: City Growth and Electrification Capital Programs

Capital Program	Investment ($ Millions)
Customer Connections[50]	$476
Externally Initiated Plant Relocations & Expansions[51]	$76
Load Demand[52]	$236
Generation Protection, Monitoring, and Control[53]	$35
Non-Wires Solutions[54]	$23

[47] Exhibit 2B, Section D4
[48] Exhibit 2B, Section D4
[49] Exhibit 1B, Tab 4, Schedule 1
[50] Exhibit 2B, Section E5.1
[51] Exhibit 2B, Section E5.2
[52] Exhibit 2B, Section E5.3
[53] Exhibit 2B, Section E5.5
[54] Exhibit 2B, Section E7.2

Capital Program	Investment ($ Millions)
Stations Expansion (Exhibit 2B, Section E7.4)	$173
Growth Capital	**$1,020**

A5.3 Grid Modernization

Toronto Hydro's grid modernization strategy focuses on accelerating the deployment pace of digital field and operational technologies that can deliver future benefits to customers. These benefits include better outage restoration capabilities to improve grid reliability and resilience, and enhanced operational flexibility to manage a more heavily utilized system with increasing bi-directional power flows. Grid modernization investments, once fully implemented and integrated in the next decade, are expected to yield a material step-change improvement in reliability and operational efficiency, to help offset the added reliability and cost pressures associated with electrification.[55]

The modernization plan lays the groundwork for grid automation (commonly known as the self-healing grid) in the horseshoe area of the system starting in 2030 to provide the enhanced levels of reliability and resilience that customers will expect as they electrify their homes and business at a lower cost compared to traditional alternatives. To improve resiliency against major disruptions (e.g. extreme weather; loss of supply) for vulnerable parts of the system, the modernization plan also includes investment in: (a) the targeted undergrounding of equipment to harden vulnerable areas of the overhead system against more frequent and extreme weather events, and (b) enhanced configuration options for the downtown network which serves critical loads such as major hospitals and financial institutions.

Toronto Hydro's journey towards an intelligent self-healing grid is being implemented through an Advanced Distribution Management System ("ADMS"), a multi-faceted software platform with advanced capabilities and connected applications that integrate analytics, real-time data and control algorithms to optimize distribution network operation. The system provides a holistic view of the grid and encompasses advanced applications such as Outage Management System ("OMS"), Fault Location Isolation and Service Restoration ("FLISR"), Volt/Var Optimization, which allow swift detection and response to outages and grid disturbances, and enable reliable and efficient

[55] Exhibit 2B, Section D5

management of DERs by optimizing voltage levels and reactive power flows throughout the distribution system.[56]

Through operational technology such as sensors and switches and software, Toronto Hydro can better monitor, predict, and control the flow of electricity across the system. These capabilities enable the utility to reduce the number and length of outages customers experience, and also pave the way for a more interactive, bi-directional grid that enables customers to choose various technologies to produce, store and sell power back to the grid.[57] In addition, Toronto Hydro plans to invest in overhead and underground line sensors and other condition monitoring and control equipment that provide the utility real-time information about critical assets in the field, and enable more cost-effective system planning and operational decisions.[58]

Modernization investments also create a foundation for the kinds of advanced, real-time and predictive analysis that would be fundamental to Toronto Hydro's evolution toward Distribution System Operator ("DSO") model, if and when such a model is either imposed or offered to distributors in an effort to further enable energy transition outcomes. In such a model, Toronto Hydro would be expected to safely and reliably coordinate, dispatch, and optimize thousands of behind-the-meter generators and flexible loads in order to help maximize the value created by the local energy system for customer, including maximizing the penetration and utilization of non-emitting energy sources. While the policy environment surrounding the role of DERs in the energy transition remains unsettled, the grid modernization capabilities advanced by the 2025-2029 Investment Plan create the foundation for this possible future while also delivering many other tangible benefits to customers irrespective of the DSO policy framework.[59]

Table 8 below outlines Toronto Hydro's modernization capital programs:

Table 8: Modernization Capital Programs

Capital Program/Segment	Investment ($M)
System Enhancement[60]	$151

[56] Exhibit 2B, Section E8.4, Appendix A
[57] Exhibit 2B, Section D5
[58] Exhibit 2B, Section E7.1
[59] Exhibit 2B, Section D5
[60] Exhibit 2B, Section E7.1

Capital Program/Segment	Investment ($M)
Network Condition Monitoring and Control[61]	$6
Metering[62]	$248
Overhead Resiliency[63]	$86
Stations Control and Monitoring[64]	$65
IT Cyber Security & Software Enhancements[65]	$95
Modernization Capital	**$651**

In addition, to the modernization capital investments summarized above, Toronto Hydro proposed to establish a $16 million 2025-2029 Innovation Fund to support the design and execution of pilot projects focused testing of innovative technologies, advanced capabilities, and alternative strategies that enable electrification grid readiness and facilitate DER integration. The Innovation Fund supports utility investment in innovation work that is more early stage, exploratory and developmental in nature, where the outcomes are less certain, but the potential benefits for the system and customers could be significant. While the benefits of individual projects may not be immediate or certain, and some initiatives may prove to be more or less fruitful than others, this type of work is nevertheless critical to achieving real innovation during a time of transformation in the energy sector.[66]

A5.4 General Plant

Toronto Hydro needs to maintain facilities, fleet and information technology ("IT") assets and infrastructure to enable efficient business operations. To get maximum value of its work centers, stations buildings, physical security systems, and fleet, the utility monitors and manages asset age and condition with a view to optimizing total lifecycle costs.

[61] Exhibit 2B, Section E7.3
[62] Exhibit 2B, Section E5.4
[63] Exhibit 2B, Section E6.5
[64] Exhibit 2B, Section E6.6
[65] Exhibit 2B, Section E8.4
[66] Exhibit 1B, Tab 4, Schedule 2

In addition to four work centers that provide the necessary conditions for employees to work effectively, Toronto Hydro manages a broad portfolio of approximately 185 stations which house and protect critical equipment such as cables and transformers. Like electrical equipment, facilities assets that are in poor condition pose an increased risk of failure putting key outcomes such as safety, reliability, customer service and productivity at risk. For example, if a station building has a leaking roof or foundation that allows water to infiltrate, there could be permanent damage to distribution equipment leading to lengthy and costly power interruptions and posing hazards to workers and the public.[67]

Investments in the renewal and maintenance of facilities assets enable the utility deliver its services in a safe, reliable, and sustainable manner. In addition to these table stakes, Toronto Hydro must also address emerging needs to provide greater resilience against physical threats such as vandalism and natural threats such as extreme weather. The utility plans to address these needs through targeted investments in renewing stations buildings and work centres (e.g. exterior cladding, windows, and roofs where critical equipment is housed), and physical security systems (e.g. network-based cameras and access card readers).

Toronto Hydro crews also need safe and reliable vehicles to execute a wide-range of system capital and operations and maintenance work programs. Toronto Hydro's fleet investments include heavy duty and light duty vehicles and equipment (e.g. forklifts and trailers). These vehicles transport employees and materials to and from job sites, perform distribution work onsite, and serve as working space for field employees. Fleet vehicles must be available to support these operations in a safe and efficient manner. Toronto Hydro's fleet investments aim to optimize vehicle operating costs, minimize fleet downtime due to repairs, increase vehicle efficiency and safety, and importantly reduce emissions.[68]

Toronto Hydro is committed to reducing its direct greenhouse gas ("GHG") emissions (referred to as Scope 1 emissions) in order to mitigate the impacts of climate change and reach "net zero" by 2040. The utility intends to reduce the emissions produced by its fleet by gradually increasing the complement of electric and hybrid vehicles. Similarly, Toronto Hydro has a paced plan to reduce its buildings emissions by decreasing its natural gas consumption using a combination of energy

[67] Exhibit 2B, Section E8.2
[68] Exhibit 2B, Section E8.3

efficiency measures and fuel switching projects to replace natural gas fueled heaters with electric heating systems.[69]

Finally, General Plant includes investments in information and operational technology ("IT/OT") assets that support a number of business applications and systems which are essential to conducting day-to-day operations such as managing field crews, responding to outages and enabling customer self-serve tools. When these systems are not available, customers service levels decrease, power outages and operational disruptions take longer to fix, and safety of the public and employees is put at risk. Toronto Hydro must invest in upkeeping its IT/OT assets highly reliable and available for conducting critical operations.[70]

Table 9 below outlines Toronto Hydro's general plant capital programs:

Table 9: General Plant Capital Programs

Capital Program/Segment	Investment ($M)
Enterprise Data Centre (Exhibit 2B, Section E8.1)	$72
Facilities Management and Security (Exhibit 2B, Section E8.2)	$145
Fleet and Equipment Services (Exhibit 2B, Section E8.3)	$44
Information and Operational Technology (Exhibit 2B, Section E8.4)	$206
General Plant Capital	**$467**

A5.5 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. Toronto Hydro's Productivity evidence at Exhibit 1B, Tab 3, Schedule 3, describes a number of specific productivity initiatives with cost savings and/or other qualitative benefits. The capital program narratives in Sections E5 through E8, and the OM&A narratives in Exhibit 4, Tab 2,

[69] Exhibit 2B, Section D7
[70] Exhibit 2B, Section E8.4

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 2025-2029 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 System Enhancement program (Section E7.1). 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 addition, Toronto Hydro anticipates cost savings related to network system maintenance due to the Network Condition Monitoring and Control program (Section E7.3), 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, and summarized within Toronto Hydro's Grid Modernization Narrative (Section D5).

- **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), Underground Renewal – Downtown (Section E6.3), 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. The upgrade of feeders from 4 kV to 13.8 kV or 27.6 kV feeders is expected to improve the capacity to connect customers, resulting in more cost-efficient connections. The replacement of deteriorating and obsolete cable types from the system is anticipated to reduce the potential exposure to lead and asbestos classified as Designated Substances under the *Occupational Health and Safety Act*.[71] Furthermore, this initiative is also expected to reduce costs associated with maintaining non-standard assets (e.g., PILC and AILC cable), reduce line losses and increase feeder capacity to connect customers as legacy undersized cable 250 or 350 PILC cables are upgraded to standard 500 kcmil TRXLPE.

- **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.
- **Flexibility Services:** Flexibility Services at Toronto Hydro refers to programs that address localized distribution issues through targeted procurements with customers or other third-parties. From the 2025-2029 period Toronto Hydro will aim to procure up to 30 MW of demand response capacity in the Horseshoe North area. This could help defer or avoid anywhere between 23 percent to 54 percent of the total load required to be transferred in this area. This translates to deferred and more likely avoided capital expenditures in the range of $10 million, at a projected cost of about $5.7 million in operating expenditures.
- **Safety and Environmental Costs:** Employee and public safety is paramount for Toronto Hydro and a significant driver of capital investment during the 2025-2029 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. Toronto Hydro's emphasis on safety not only protects its workforce and the public but also generates significant cost savings. With an exemplary safety record, the utility benefits from reduced Workplace Safety Insurance Board premiums, allowing for more resources to be allocated to vital projects and innovations. Additionally, their commitment to environmental sustainability through investments in renewable energy and eco-friendly practices not only reduces their

[71] RSO 1990, c. O.1

environmental impact but also leads to lower operating costs, ensuring both financial stability and responsible resource management.

- **Advanced Technological Solutions**: By effectively harnessing advanced technology solutions, such as infrared thermography for early anomaly detection, electronic maintenance sheets for streamlined data handling, and online partial discharge testing for proactive maintenance. Toronto Hydro can significantly enhance its work coordination during maintenance outages. This approach allows for timely identification and resolution of potential issues, leading to reduced equipment failures and unplanned downtime. Ultimately, the adoption of these cutting-edge tools fosters cost-saving measures while bolstering the overall reliability and performance of the electrical grid.
- **Facilities Asset Management System:** Toronto Hydro has a robust facilities management system that records assessments and maintenance plans for all assets located in Toronto Hydro's work centres and stations. Through this proactive facilities management system, Toronto Hydro minimizes unnecessary expenditures on premature asset replacements, translating into significant cost savings. By precisely identifying assets in poor condition and approaching replacements strategically, Toronto Hydro can allocate its financial resources more effectively, investing in critical areas that contribute to the overall reliability and performance of its infrastructure. This approach not only emphasizes cost saving but also underscores Toronto Hydro's commitment to responsible and efficient asset management, benefiting both the organization and its customers in the long run.
- **Procurement:** Toronto Hydro maintains a strategic approach by utilizing a combination of internal and external resources to execute its extensive capital and maintenance programs. The utility employs a competitive procurement process to determine the majority of costs associated with its capital work program. Despite anticipated challenges like rising construction costs due to labor market pressures and increased congestion in Toronto, the utility's competitive procurement strategy remains instrumental in securing essential resources at reasonable rates, ensuring the successful execution of the capital plan while emphasizing cost-effectiveness. This strategic approach enables Toronto Hydro to manage financial resources efficiently, ultimately benefiting both the organization and its customers. Additionally, major world events like the COVID-19 pandemic, changes to work patterns, geopolitical conflict, and high inflation significantly disrupted the global supply chain. This led to risks in timely and cost-effective material procurement. To address these challenges

and ensure a reliable supply, Toronto Hydro updated its strategy. This revised approach includes a comprehensive assessment of supply chain risks and a mix of proactive long-term measures and reactive short-term actions. The strategy takes a 360-degree view of Toronto Hydro's current and into the short- and medium-term, as informed by engagements with business units, while simultaneously keeping track of market conditions through touchpoints with vendors and manufacturers.

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. In the context of Toronto Hydro's large asset renewal backlog, 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.

A6 Capital Expenditure Plan

A6.1 Capital Programs and Drivers

The 2025-2029 Capital Expenditure Plan in the DSP consists of 20 unique capital programs. These programs are allocated to each of the OEB's four major investment categories, as defined in Table 10, based on their trigger drivers, which represent the primary reason a program must be carried out.

Table 10: Capital Investment Categories

System Access	• Toronto Hydro fulfills its obligation by undertaking necessary modifications, such as asset relocation, to ensure that customers, including generators, or groups of customers, can seamlessly access and benefit from reliable electricity services through the distribution system.
System Renewal	• Toronto Hydro optimizes its distribution system by strategically replacing and refurbishing system assets. This proactive approach ensures the reliability of electricity services for customers by managing failure risk as the utility maintains a robust infrastructure capable of meeting their energy needs in the short and long terms, while also investing in improving system resiliency.

System Service	• Toronto Hydro proactively modifies its system to effectively meet operational objectives, improve efficiency, and anticipate future customer electricity service requirements. The utility modernizes its grid to ensure reliable and efficient service delivery for its customer in line with evolving demands.
General Plant	• Toronto Hydro proactively undertakes modifications, replacements, or additions to assets beyond the distribution system, encompassing land, buildings, tools, equipment, rolling stock, and electronic devices and software. These efforts are geared towards supporting the utility's day-to-day business and operational activities, fostering efficiency, reliability, security, and adaptability in delivering energy services to its customers.

Each capital program is defined by a single trigger driver and a number of secondary drivers. The trigger drivers for Toronto Hydro's 2025-2029 DSP programs are summarized in Table 11, 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 11: Investment Category Trigger Drivers

Category	Driver	Description
System Access	***Customer Service Requests***	• Toronto Hydro strives to connect demand and distributed energy resource ("DER") customers to its system as efficiently as possible in alignment with its obligation under the *Distribution System Code*. This obligation holds unless it poses safety concerns for the public or employees or compromises the reliability of the distribution system. In situations where the existing infrastructure falls short of enabling a connection, the utility undertakes system expansions or enhancements to accommodate the customer's needs.
	Mandated Service Obligation	• Toronto Hydro prioritizes full compliance with all legal and regulatory requirements and government directives.
System Renewal	***Functional Obsolescence***	• Specific asset types and configurations can become obsolete for a variety of technical and operational reasons. Typically, functionally obsolete assets can no longer be effectively maintained or utilized as intended. Toronto Hydro will act to

Category	Driver	Description
		retrofit or replace these assets within a timeframe that is specific to the unique circumstances of the asset population in question.
	Failure	• Toronto Hydro must reactively repair or replace assets or critical components that have failed while in service.
	Failure Risk	• Toronto Hydro takes proactive measures to identify, assess, and mitigate failure risk within its asset populations. Failure risk is determined by evaluating the likelihood of failure (e.g., by leveraging asset condition assessments) and the likely impact of failure ("criticality") on various outcomes, including safety, reliability, cost, and the environment. By prioritizing service reliability and ensuring the safety of workers and the public, the utility strives to maintain a robust infrastructure that meets the evolving needs of its customers.
System Service	***Reliability***	• Toronto Hydro strives to maintain and improve reliability at local, feeder-wide, and system-wide levels by continuously optimizing its system and deploying cost-effective technologies and solutions.
	Capacity Constraints	• Expected load changes can impact service consistency and demand requirements for the system. To address this, Toronto Hydro proactively adjusts and expands its infrastructure to optimize reliability and meet evolving customer needs.
General Plant	***Operational Resilience***	• Toronto Hydro prioritizes the ability to mitigate and recover from disruptions to core business functions. Through robust strategies, contingency plans, and proactive risk management, the utility ensures prompt restoration of operations, minimizing impact and maintaining service continuity.
	System Maintenance and Capital Investment Support	• Toronto Hydro recognizes the significance of investing in day-to-day operational activities, as doing so enables the utility to prioritize the safety and well-being of its employees while maintaining an environment that fosters efficiency and reliability in delivering essential services.

A6.2 2020-2029 Capital Expenditure Plan

Table 12 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 2020 to 2024 and over the forecast period from 2025 to 2029. A detailed discussion of expenditure variances and trends over the 10-year 2020-2029 period is provided in Section E4.

Table 12: Historical (2020 to 2024) and Forecast (2025 to 2029) Expenditures ($ Millions)

Category	Actuals			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Access	80.4	140.3	128.4	127.1	153.7	226.5	239.3	228.3	192.8	184.8
System Renewal	261.5	247.3	276.5	314.0	358.8	359.7	366.5	391.3	423.7	429.1
System Service	32.8	68.4	67.2	32.8	24.3	38.3	35.3	83.0	95.1	101.2
General Plant	56.1	72.4	112.9	96.5	80.7	103.9	119.1	124.9	116.1	98.6
Other	17.4	4.6	12.8	12.6	7.7	6.3	7.0	8.7	10.3	12.0
Total CapEx	448.1	533.2	597.9	582.9	625.3	734.6	767.3	836.2	837.9	825.7
System O&M	117.1	117.5	124.1	127.1	135.0	144.1	148.9	153.0	159.0	164.5

Detailed analysis for each program is included in Sections E5 through E8 of the DSP, including analysis of historical expenditures and accomplishments, justifications for 2025-2029 expenditures, and options analysis.

A7 Outcomes and Performance Measurement

In developing its approach to performance measurement for the Distribution System Plan ("DSP"), Toronto Hydro considered the Ontario Energy Board's guidance, including the *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRF").[72] A key theme of the Ontario Energy Board's guidance is that utilities should align their investment plans with customer needs, and adopt an outcomes-based approach to tracking their performance.

Toronto Hydro's 2025-2029 performance measurement framework consists of (1) performance outcomes consistent with the Ontario Energy Board's Renewed Regulatory Framework ("RRF") categories, and (2) a custom scorecard that is tied to an innovative Performance Incentive Mechanism ("PIM") as part of the 2025-2029 custom rate framework (Exhibit 1B, Tab 2, Schedule 1).

In respect of the first component – RRF outcomes – Toronto Hydro intends to continue delivering high-performance on the Electricity Distributor Scorecard ("EDS") and the Electricity Service Quality Requirements ("ESQR") consistent with the historical results presented in Exhibit 1B, Tab 3, Schedule 2. To that end, each capital and operational program outlined in the DSP and Exhibit 4, Tab 2 (operations) includes a performance outcomes table that explains how the program advances specific RRF objectives.

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, or make necessary day-to-day operational investments. The choices made reflect 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.

Toronto Hydro sets asset management objectives that are aligned with the overall investment plan objectives, and are a result of the detailed, iterative, and customer engagement-driven planning process summarized in Section E2 of the DSP. Section D1.2.1 explains the link between Toronto Hydro's distribution system Asset Management System ("AMS") and its performance measurement framework with respect to the investment priorities of the plan.

As further detailed in Exhibit 1B, Tab 3, Schedule 1, Toronto Hydro's 2025-2029 Custom Scorecard tracks performance across four performance categories. By monitoring and managing the

[72] Ontario Energy Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (October 18, 2012).

performance measures identified in each category of the custom scorecard (see Table 13 below), in addition to the EDS, ESQR and Asset Management performance measures noted above, the utility expects to drive continuous and sustained improvement across the organization in the next rate period in a manner that aligns with Ontario Energy Board and customer feedback, and also reflects the key objectives and underpinnings of the plan.

Table 13: 2025 – 2029 Performance Incentive Scorecard Measures

Performance	Measure
System Reliability & Resilience	**Outage Duration:** System Average Interruption Duration Index (SAIDI) excluding MEDs, Loss of Supply and Planned Outages
	Outage Frequency: System Average Interruption Frequency Index (SAIFI) - Defective Equipment
	System Security Enhancements: Deliver initiatives that enhance Toronto Hydro's physical and cyber security posture against the NIST framework
Customer Service & Experience	**New Services Connected on Time:** Percentage of new connections and service upgrades completed on time consisting of Low Voltage Connections (70%), High Voltage Connections (20%) and DER Connections (10%)
	Customer Satisfaction: Customer post-transactional surveys for Phone Inquiries, E-Mail Inquiries, Key Accounts engagements, Construction Communications, Outages Communications, and Customer Connections
	Customer Escalations Resolution: Percentage of customer escalations resolved within 10 business days.
Environment, Safety and Governance	**Total Recordable Injury Frequency (TRIF):** Injuries per 100 employees (or 200,000 hours worked) per year.
	Emissions Reductions: CO2e emissions produced by the utility's fleet and facilities.
	ISO Compliance and Certification: Achieve and maintain certification with select ISO governance standards, specifically achieve ISO 55001 (60%), and maintain ISO14001 (20%) and ISO45001 (20%).
Efficiency & Financial Performance	**Efficiency Achievements:** Sustained benefits for customers in the form of reduced or avoided costs or other benefits that will produce a lower revenue requirement in the next rebasing
	Grid Automation Readiness: Completion of technology milestones that will enable the implementation of fully automated, self-healing grid operations beginning in 2030
	System Capacity (Non-Wires): Flexible system capacity procured through demand response offerings.

A8 Third-Party Studies and Reports

The 2025-2029 DSP is supported by a several expert studies and reports.

Table 14: Third-Party Studies Filed in Support of the 2025-2029 DSP

Study	Vendor	Description/Reference
Econometric Benchmarking of Historical and Projected Total Cost and Reliability	Clearspring	Clearspring 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. Clearspring 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. Clearspring's results indicated that (i) the historical average total costs for the utility, from 2020 to 2022, are 28.0 percent below benchmark expectations; and (ii) the projected total cost levels during the 2025-2029 period are 22.9 percent below benchmark expectations. Based on their findings, Clearspring states that Toronto Hydro is not a poor total cost performer and recommends a stretch factor of 0.15 percent. Clearspring also benchmarked Toronto Hydro's reliability performance, finding that the average frequency of interruptions (SAIFI) was above the predicted benchmark by 98.8 percent, but the customer average interruption duration (CAIDI) was below benchmark by 104.1 percent. The study can be found at Exhibit 1B, Tab 3, Schedule 3, Appendix A.
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 unit costs for major asset classes and maintenance activities for the 2020-2022 period. UMS compared these results to those of peer utilities across North America, considering dollar and metric conversions and accounting differences. Overall, UMS found that Toronto Hydro's unit costs ranged from minus 12.2 percent to plus 1.9 percent relative to the median. UMS also noted that if certain qualitative considerations, such as customer density, were statistically normalized for, Toronto Hydro's comparative ranking would be better than shown. The study can be found at Exhibit 1B, Tab 3, Schedule 1, Appendix C.

Study	Vendor	Description/Reference
Climate Change Vulnerability Assessment Update	Stantec	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. In 2022, Toronto Hydro retained Stantec to update the 2015 study, which recommended not relaxing any adaptation measures from the previous study. This information informed the development of Toronto Hydro's 2025-2029 DSP. The study can be found at Exhibit 2B, Section D2, Appendix A.
Enterprise IT Cost Benchmark & Functional Maturity Assessment	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 ("Gartner"). Gartner concluded that Toronto Hydro's IT expenditures as of 2022 benchmark competitively against industry peers and the increase in Toronto Hydro's 2022 IT spending compared to 2017 is similar to 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 the exception of higher allocations to Applications spending (51.2 percent of IT spend for Toronto Hydro versus 41.9 percent for peers, largely due to the Customer Information System ("CIS") Upgrade and IT Management and Administration (14.8 percent of IT spend for Toronto Hydro versus 10.8 percent for peers, largely due to increased investment in Cyber Security services)." The study can be found at Appendix A to Exhibit 2B, Section D8.

Study	Vendor	Description/Reference
Future Energy Scenarios Report	Element Energy	To better understand the challenges posed by the changing energy landscape, Toronto Hydro engaged a leading UK consultant Element Energy, who has developed a Future Energy Scenarios modelling tool. The Future Energy Scenarios provide an overview of possible future changes to power demand, energy consumption, generation, and storage across Toronto and an assessment of their potential impacts on the Toronto Hydro electricity distribution network. The Future Energy Scenarios confirms that Toronto can expect significant changes to its energy system resulting from electrification, renewable generation deployment, and improvements in energy efficiency. The report can be found at Appendix B, to Exhibit 2B, Section D4.
Review of ACA Modelling Enhancements and Customisations	EA Technology	Toronto Hydro retained EA Technology to guide and review improvements to its ACA methodology, to ensure that it continues to align with the core principles of the Common Network Asset Indices Methodology ("CNAIM"), as well as to identify opportunities for continuous improvement. EA Technology found that Toronto Hydro has made significant progress, while retaining alignment with CNAIM, but expects it to continue to evolve as part of natural process, providing specific areas for improvement. The report can be found at Exhibit 2B, Section D3, Appendix B.

B Coordinated Planning with Third Parties

B1 Introduction

This section provides an overview of how Toronto Hydro coordinates infrastructure planning with third parties, and how those consultations affect Toronto Hydro's Distribution System Plan ("DSP"). Toronto Hydro has a robust approach to coordinating and integrating third-party infrastructure planning information into its distribution system planning process. The utility coordinates infrastructure planning with a wide-range of external stakeholders including: customers (e.g., large customers, subdivision developers, and municipalities), the Independent Electricity System Operator (IESO), the transmitter ("Hydro One") and other distributors as part of regional planning process, and other entities and agencies such as telecommunication and transit providers (e.g. Metrolinx).

Generally, Toronto Hydro coordinates with third parties by participating in forums and processes that are organized and led by governmental or delegated authorities. For example, Toronto Hydro exchanges planning documents and project execution information with large developers and telecommunication entities through municipal planning and permitting processes. The City of Toronto requires infrastructure entities to circulate their plans in order to obtain permits to carry out work. Please see Section B2 Customer Coordination below for further details about Toronto Hydro's participation in the City of Toronto's infrastructure planning coordination activities.

Similarly, Toronto Hydro engages with the transmitter and other distributors, along with other local stakeholders through the IESO's Regional Planning Process ("RPP"). The RPP is part of the IESO's statutory mandate to conduct independent planning for electricity generation, demand management, conservation and transmission.[1] Given the high degree of technical alignment needed between upstream transmission assets and downstream distribution assets, the RPP requires close coordination between the IESO and transmission and distribution utilities. Please see Section B3 Electricity System Planning below for further details about Toronto Hydro's participation in RPP.

Regulations recently came into effect requiring distributors to consult any telecommunication entity that operates within its service area for the purpose of distribution system planning.[2] Please see

[1] Section 6(1) of the *Electricity Act, 1998,* S.O. 1998, c. 15, Sched. A
[2] *Supporting Broadband and Infrastructure Expansion Act, 2021.* Ontario Regulation. 842/21 made under the *Ontario Energy Board Act,* S.O. 1998, Ch 15, Sched. B.

Section B4 – Telecommunication Entities below for an overview of the utility's processes for coordinating infrastructure planning with telecommunication entities within its service territory.

B2 Customer Coordination

B2.1 Overview

Toronto Hydro coordinates infrastructure planning with customers including large developers and infrastructure agencies, as well the City of Toronto. These engagements provide Toronto Hydro key planning information that can be integrated into the utility's Peak Demand Forecast described in Section D4 - Capacity Planning and Electrification. They also enable effective operational planning and execution of major infrastructure relocation projects, as well as capital projects more generally.

B2.2 Proactive Customer Engagement

Toronto Hydro's Development Planning team leverages the City of Toronto's development pipeline to engage large customers and developers with upcoming projects to understand their needs, determine their load requirements and timelines, provide technical guidance, explore innovation opportunities, and provide support in understanding the connection process.[3] These engagements usually occur up to five to eight years before an intended connection materializes, enabling a smoother connection experience for customers and providing Toronto Hydro with valuable insight into emerging technologies that customers are adopting behind-the-meter, that can drive significant load growth or change in demand patterns in certain parts of the grid. Accordingly, these engagements enable Toronto Hydro to incorporate anticipated connections into its Peak Demand Forecast with a higher degree of confidence. Based on this forecast, Toronto Hydro determines investment needs in demand-driven program such Stations Expansion and Load Demand, to manage capacity constraints and plan for future load growth on the distribution system. For further information please refer to sections E5.3 Load Demand and E7.4 Stations Expansion.

B2.3 External Requests

Toronto Hydro manages a large number of requests by third parties to relocate distribution assets in order to accommodate public infrastructure such as city works, roads and highways and other types of development projects such as public transit. When a request for relocation is received, Toronto

[3] The Development Planning team works with the Key Accounts team who is responsible for managing relationships with customers and developers. For more information about Key Accounts please refer to Exhibit 4, Tab 2, Schedule 9.

Hydro also reviews load demand projections in the vicinity of the project(s) to evaluate whether there are opportunities to efficiently increase capacity in conjunction with the relocation work. When capacity needs are identified in the surrounding area, Toronto Hydro integrates expansion work into the third party's relocation project. For more information please refer to section E5.2 Externally Initiated Plant Relocations and Expansion.

B2.4 Capital Program Delivery

Toronto Hydro coordinates the execution of its capital work with the City of Toronto through use of the City of Toronto Project Tracking Portal ("PTP") as well as regular meetings with the City of Toronto's Infrastructure Coordination Unit ("ICU") and the City of Toronto's Toronto Public Utilities Coordination Committee ("TPUCC").[4][5] The ICU acts as a coordinating body for all groups – not just City agencies – that perform construction work in the city. This coordination often enables construction by different groups to be bundled together, avoiding additional disruption.[6] The TPUCC is a consortium established by the City of Toronto and utility companies to provide a forum for discussion in order to table ideas, encourage safety and implement innovative ways of reducing the impact and inconvenient of construction projects. Membership of the TPUCC consists of utilities that provide transportation, telecommunication, energy (gas), and water services in the City of Toronto including, Toronto Hydro, Enbridge Gas Distribution, Enwave Energy Corporation, Hydro One Networks Inc. Bell Canada, Beanfield Metroconnect, Rogers Cable Communications Inc., Telus, and Toronto Transit Commission. These engagements allow Toronto Hydro to resolve conflicts between its capital program and the City of Toronto, including by fast tracking or postponing projects to better align with other scheduled projects.

Toronto Hydro also responds to requests to adjust its work in response to social and cultural programs, such as filming requests and City of Toronto programs that permanently or temporarily affect the use of public sidewalks and roadways including CaféTO (for restaurant and bar spaces) and ActiveTO (for physical activity, community safety, and cycling spaces).

[4] City of Toronto, Infrastructure Viewer, online, https://map.toronto.ca/toinview/
[5] More information on the TPUCC and construction coordination in the City can be found here: https://www.toronto.ca/services-payments/building-construction/infrastructure-city-construction/understanding-city-construction/construction-coordination-in-the-city/
[6] City of Toronto, Construction Coordination in the City, online, https://www.toronto.ca/services-payments/building-construction/infrastructure-city-construction/understanding-city-construction/construction-coordination-in-the-city/

B3 Electricity System Planning

Toronto Hydro participates in the electricity system planning processes, particularly the Regional Planning Process, which produces 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 Toronto Region and Greater Toronto Area (“GTA”) North Region, led by Hydro One Networks Inc. Toronto Hydro’s DSP has been informed by the results of the completed regional plans, and Toronto Hydro continues to coordinate with the aforementioned parties with respect to plans that are under development. The following sections describe the coordinated planning approach and results from the ongoing Regional Planning Process.

B3.1 Regional Planning Process Consultations

Regional planning looks at supply and reliability issues at regional and local levels with a focus on the 115 kV and 230 kV portions of the provincial system. The provincial grid is divided into several regions or zones for which plans are developed.

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 that supply the load and the transmission circuits between the stations. It also includes the 115 kV and 230 kV auto-transformers and their associated switchyards. From a resource perspective, regional planning considers local distributed generation, Conservation and Demand Management (“CDM”), as well as other forms of Non-Wires Solutions (“NWS”) that could be developed to address supply and reliability issues in a region or local area.

Local Distribution Companies (“LDCs”) conduct wires and NWS 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 below in Section B3.2.

Regional planning can overlap with provincial system planning and distribution system planning. At Toronto Hydro, the same people responsible for the planning that informs the distribution system plan are also involved in regional planning. Overlaps with distribution system planning occur largely at the transformer stations that supply distributors, and at large directly-connected customers. For example, co-ordination is necessary when planning for the construction of new transformer stations such as the recently completed Copelands TS that serves the expanded downtown core. Regional planning may also require coordination with distribution planning when a distribution solution can address needs of the broader local area or region, for example, by providing load transfers between transformer stations.

The following subsections describe key elements of the regional planning consultations. This is an iterative process and consultations occur at different points throughout the regional planning process.

B3.1.1 Stakeholder Consultations

The Regional Planning Process includes community and stakeholder engagement, including webinars, led by the IESO. The IESO invites the City of Toronto, First Nations, and Métis communities, stakeholders, community groups and the general public to provide input on the Scoping Assessment Outcome Report and development of the IRRP that is currently underway. The inaugural webinar occurred in March 2023, and coincided with the publication of the Scoping Assessment Outcome Report. Based on discussions with the IESO, Toronto Hydro understands that stakeholder consultation on the demand forecast and supply/delivery options and recommendations will take place after the filing of the Application.

B3.1.2 Transmitter Consultations

Toronto Hydro consults with Hydro One through regional planning processes, and in particular the RIP which is led by the transmitter.

Hydro One launched the new regional planning cycle in August 2022, starting with a Needs Assessment update. The Toronto Region Needs Assessment Report was completed in December 2022, and is provided as Appendix A to this section.

The most recent Metro Toronto RIP, that covers Toronto Hydro's service area, was completed in March 2020.[7] The most recent GTA North RIP, that covers a neighbouring region important to Toronto Hydro's operations, was completed in October 2020.[8] Both reports are being updated through the regional planning cycle currently underway.

[7] Exhibit 2B, Section B, Appendix B – Toronto Regional Infrastructure Plan (March 2020).
[8] Exhibit 2B, Section B, Appendix C – GTA North Regional Infrastructure Plan (October 2020).

B3.1.3 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.

B3.1.4 IESO Consultations

Toronto Hydro actively consults with the IESO as part of Integrated Regional Resource Plan ("IRRP"). The most recent IRRP was completed in 2019.[9] The IESO launched a new IRRP process for the Toronto Region in the spring of 2023. Toronto Hydro is the host distributor for that IRRP and is actively consulting with the IESO, Hydro One and other stakeholders, including the City of Toronto and the public.

B3.1.5 Municipality Consultations

As part of the Regional Planning process, Toronto Hydro, the IESO, and Hydro One engage with the City of Toronto. Through these engagements, the planners put their demand forecasts and supply/delivery options and recommendations to the municipal government for feedback with the goal of aligning expectations based on the plans and priorities of the City of Toronto.

B3.2 Regional Planning Process

Distribution system planning provides inputs to regional planning through peak demand forecast that triggers a needs assessment. Planning considerations in the Toronto Region include:

- 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 the past, Toronto Hydro's service area was split between Central Toronto and Northern Toronto. More recently, regional planning considers Toronto Hydro's service area, the City of Toronto, on a consolidated basis as the Toronto Region. Planning documents and reports that have been developed, issued, and relied upon

[9] Exhibit 2B, Section B, Appendix D – Toronto IRRP Report (August 2019).

for Toronto Hydro's plans for the 2025-2029 period are based on the planning region being the Toronto Region. Planning triggers such as changes in demand or asset condition, initiate the regional planning process and progresses through the following phases:

i. Needs Assessment (NA);
ii. Scoping Assessment;
iii. Integrated Regional Resource Plan (IRRP); and
iv. Regional Infrastructure Plan (RIP).

B3.2.1 Needs Assessment

The lead transmitter in a given region, in this case Hydro One, coordinates and leads the Needs Assessment phase with input from the local LDC(s) and the IESO. Combined, they constitute what is known as the Study Team. The Study Team is provided with a range of inputs from both the LDC, in the form of a peak demand forecast, and the IESO in the form of CDM and DER penetration forecasts. The needs of the various high voltage assets in the region are then identified over the medium and long term to ensure adequate capacity is available to connect forecasted load while continuing to operate the grid in a reliable and safe manner. At the conclusion of the Needs Assessment, the Study Team will categorize asset needs as either requiring further regional planning coordination involving more advanced stages of the process or local planning between the affected LDC and lead transmitter only. Toronto Hydro and Hydro One completed a Needs Assessment in December 2022, the details of which are in Appendix A. This report reflects key aspects of the Stations Expansion Program in section E7.4

B3.2.2 Scoping Assessment

If the Study Team recommends that additional planning is required to assess a particular need or group of needs, the IESO then initiates a Scoping Assessment phase and leads the process in collaboration with the host LDC, in this case Toronto Hydro, and the lead transmitter, Hydro One. A thorough review of the needs identified in the Needs Assessment phase is conducted with an aim to determine if a mix of wires and non-wires solutions – which may comprise conservation and demand management, and distributed generation or energy storage – can address the identified needs. Needs that can benefit from an integrated (wires plus non-wires) solution proceed to an IRRP, while those that can only benefit from a wires solution proceed to the RIP process led by Hydro One. The

IESO completed the Scoping Assessment report in March 2023, which can be found in Appendix E to this section.[10]

B3.2.3 Toronto Integrated Regional Resource Plan

The Toronto Region IRRP is currently underway. 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 Toronto Region 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, and investigating the costs and benefits of conservation, distributed generation, and transmission and distribution options in meeting the future electricity needs of customers in the Toronto Region**.** 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 regional planning cycle underway for the Toronto Region is scheduled for completion in August 2024, and the impact of the regional plan on the DSP is discussed in Section E2.4.1.

B3.2.4 Toronto Regional Infrastructure Plan

The previously prepared Metro Toronto RIP was completed in March 2020 and is attached as Appendix B to this section.

The Toronto RIP for the current cycle is scheduled for completion in March 2025. This plan is the final phase of the regional planning process following the completion of the Toronto Region's IRRP by the IESO in August 2024. The RIP may be triggered earlier if a particular need identified in the IRRP cannot be met by a non-wires solution. At that point, the IESO requests Hydro One to initiate a RIP.

B3.2.5 GTA North Regional Infrastructure Plan

The GTA North RIP was completed in October 2020. The plan is attached as Appendix C to this section.

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-

[10] Exhibit 2B, Section B, Appendix E – Toronto Scoping Assessment Outcome (March 2023).

Region Integrated Regional Resource Plan by the IESO in February 2020. Because Toronto Hydro also receives supply from the GTA North Region, Toronto Hydro is a participant of the process.

Participants of the RIP included:

- Alectra Utilities;
- Hydro One Networks Inc. (Distribution);
- Independent Electricity System Operator;
- Newmarket-Tay Power Distribution Ltd.; and
- Toronto Hydro Electric System Limited.

Toronto Hydro provided input to the GTA North 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.

Hydro One launched a new GTA North regional planning cycle in March 2023, starting with a Needs Assessment update. The Needs Assessment Report for the GTA North Region was completed on July 14. 2023, and is attached in Appendix F to this section.[11] Impacts to the DSP are described in Section E2.4.1.

B4 Telecommunication Entities

B4.1 Overview

Toronto Hydro mainly relies on two consultation processes to ensure comprehensive, timely, and efficient coordination of infrastructure planning and capital project execution with telecommunication entities ("telecoms") that operate within its service area.

The first consultation process is facilitated through the City of Toronto's Toronto Public Utilities Coordination Committee ("TPUCC"), which meets once a month. Any telecom that operates within the City of Toronto is required to participate in the TPUCC in order to obtain construction permits. This forum provides Toronto Hydro a comprehensive view and opportunity to engage all telecoms that operate within its service area. The second consultation process is Toronto Hydro's attachment

[11] Exhibit 2B, Section B, Appendix F – GTA North Region Needs Assessment (July 2023).

process. Telecoms who seek to attach their infrastructure to Toronto Hydro's assets must apply and coordinate with Toronto Hydro to obtain approval.

Sections B4.2 and B4.3 below provide further details about these processes and insight into how Toronto Hydro effectively and efficiently coordinates with telecommunications entities that operate within its service area. Section B4.4 explains how telecom consultations affect the utility's capital plan.

B4.2 Municipal Forums

The City of Toronto imposes permitting requirements for the installation of infrastructure within the city of Toronto.[12] In order to maximize the efficiency of infrastructure coordination, the City of Toronto formed the TPUCC.[13] The TPUCC consists of utilities that provide transportation, telecommunication, energy (gas), and water services in the City of Toronto. In addition to Toronto Hydro, other members of the TPUCC include Bell Canada, Beanfield Metroconnect, Rogers Cable Communications Inc., Telus, and Hydro One Networks Inc.

In order to be granted permits from the City of Toronto, telecoms must submit "circulations", containing plans mapping out telecom facilities and details around the execution of the capital projects. These plans are circulated to other members, including Toronto Hydro. The utility examines the plans and ensures that they are compliant with Toronto Hydro's design and construction standards, especially where they are adjacent, or directly affixed to, Toronto Hydro's infrastructure. The circulations process provides a robust forum for consultation and co-ordination between Toronto Hydro and telecommunications entities operating in its service territory.

Since 2020, telecoms including Beanfield, Bell Canada, Rogers Cable and Cogeco have submitted over 3,200 circulations containing plans on capital project design and execution. Toronto Hydro processes these requests within an average of 5.4 days, reviewing and identifying whether there are any conflicts or contraventions of Toronto Hydro's design and construction standards (e.g., if adjacent infrastructure is planned to be constructed in close proximity to Toronto Hydro's poles). The utility typically resolves conflicts or contraventions identified in an average of four days.

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[12] More information on Municipal Consent Requirements can be found here: https://www.toronto.ca/services-payments/building-construction/infrastructure-city-construction/construction-standards-permits/standards-for-designing-and-constructing-city-infrastructure/?accordion=utility-cut-permit-applications-and-municipal-consent-requirements-mcr.
[13] *Supra* Note 5

This information sharing process occurs on a rolling basis as TPUCC members upload data on the City of Toronto's Project Tracking Portal ("PTP") and Infrastructure Viewer application ("T.O.INview"). This means that Toronto Hydro regularly accesses the most up-to-date information on telecom capital project plans and similarly, telecoms can readily access Toronto Hydro's capital project plans. Toronto Hydro, Rogers Cable, and Bell Canada are also members of the Digital Map Owners Group ("DMOG"), which is responsible for the sharing of costs and maintenance of a comprehensive database mapping out underground utility features across the City of Toronto.

B4.3 Attachment Process

Separately, Toronto Hydro manages an attachment permitting process, where third-parties including telecoms, proactively request to affix their facilities onto Toronto Hydro's assets. Initially, Toronto Hydro requests advance notice and details of attachment applications from all telecoms operating within the City of Toronto for the upcoming year. However, the bulk of the permit applications are submitted on an ongoing basis. Toronto Hydro processes the applications and assesses whether the targeted assets are capable of physically supporting third-party fixtures or whether additional work is required in the form of "hydro make-ready" (HMR) work.

Toronto Hydro cross-references the HMR projects submitted through the attachment permitting process with projects in queue on the City's PTP and T.O.INview systems, and other Toronto Hydro programs, falling mainly under System Renewal category at Section E6. Where cost-effective and efficient, Toronto Hydro incorporates the HMR work into existing projects or otherwise assigns it to a contractor pre-approved by Toronto Hydro to complete the work on behalf of the telecom in accordance with Toronto Hydro's design and construction standards.

B4.4 Effects of Telecom Consultations on Capital Plans

Inputs gathered through the telecom consultations processes described above are reflected in programs under the System Renewal category of Toronto Hydro's capital plan. Specifically:

- **Area Conversions (Exhibit 2B, Section E6.1)**: This program converts pole-top box constructions to new designs, to which third-party assets – including telecom fixtures – are often attached. Toronto Hydro cross-references its program execution plans with telecom information obtained through the attachment process in order to come up with a schedule and plan that is responsive to the needs of telecoms.

- **Underground Renewal – Horseshoe (Exhibit 2B, Section E6.2)**: This program replaces underground network assets to manage failure risk. In order to complete this work, Toronto Hydro accesses its underground assets through trenches. Telecoms often situate their fibre optic networks in Toronto Hydro's underground cable chambers in the ducts. Therefore, Toronto Hydro often cross references information from telecoms that come through TPUCC circulations, which may result in, for example, modifications to trench routes to accommodate any telecom projects.
- **Overhead System Renewal (Exhibit 2B, Section E6.5)**: This program replaces poles that are in poor condition. Toronto Hydro cross references applications for wireline attachments with its own project execution plans to coordinate the pacing and order, and if needed plan any required transfers of existing telecom assets to an alternative pole.

B5 IESO Comment on Renewable Energy Generation

B5.1 IESO Comment Letter

In accordance with section 5.2.2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications, Toronto Hydro requested and obtained a letter of comment from the IESO with respect to planned renewable energy generation ("REG") investments. This letter is filed at Appendix G to this section.

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

NEEDS ASSESSMENT REPORT

Toronto Region

Date: December 19, 2022

Prepared by: Toronto Region Technical Working Group

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Toronto Region and to recommend which need: a) does not require further regional coordination and b) identify needs requiring further assessment and/or regional coordination. The results reported in this Needs Assessment are based on the input and information provided by the Technical Working Group ("TWG") for this region.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to 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 Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	August 23, 2022	**END DATE**	December 19, 2022

1. INTRODUCTION

The second Regional Planning ("RP") cycle for the Toronto Region was completed in March 2020 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the third RP cycle for this Region, which begins with the Needs Assessment ("NA") phase. The purpose of this NA is to:

a) Identify any new needs and reaffirm needs identified in the previous RP cycle; and
b) Recommend which needs:
   i. require further assessment and regional coordination (and hence, proceed to the next phases of RP); and
   ii. do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted Local Distribution Companies ("LDC") to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the RP process, the RP cycle should be triggered at least once every five years. Considering these timelines, the third Regional Planning cycle was triggered in August 2022 for the Toronto Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the Toronto Region NA includes:
a) Reaffirm and update needs/plans identified in the previous RP cycle;
b) Identify any new needs resulting from this assessment;
c) Recommend which need(s) require further assessment and regional coordination in the next phases of the RP cycle; and
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle).

The Technical Working Group ("TWG") 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.

The planning horizon for this NA is 10 years.

4. INPUTS/DATA

The TWG representatives from LDCs, the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the Toronto Region regarding capacity needs, system reliability needs, operational issues, and major high-voltage ("HV") transmission assets requiring replacement over the planning horizon. The information was based on what was available and provided at the time of the NA, which does not include the impact from the IESO's "Pathways to Decarbonization" report published on December 15, 2022. The electricity demand and new infrastructure need in the longer term could be substantially higher than anticipated and discussed in this report. This will be further assessed in the next phase of this RP cycle.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the study period. The assessment methodology includes a review of planning information such as load forecast, conservation and demand management ("CDM") forecast, available distributed generation ("DG") information, system reliability and operation issues, and major HV transmission assets requiring replacement.

A technical assessment of needs was undertaken based on:

a) Station capacity and transmission adequacy;
b) System reliability and any operational concerns;
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and
d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification. (which does not consider the impact from the "Pathways to Decarbonization" report published by the IESO on December 15, 2022, but will be assessed in the next phase of this RP cycle)

6. NEEDS

Needs that were identified in the last RP cycle with associated projects recently done or currently underway are:

- Second DESN at Horner TS and refurbishment projects at Runnymede TS (T3/T4), Sheppard TS (T3/T4), and Strachan TS (T12) were completed in 2021-2022.
- Copeland MTS phase 2 is expected to be in-service in 2024 to address the station capacity need.
- Bridgman TS transformer replacement (T11/T12/T13/T14) is expected to be done in 2024.
- Fairbank TS transformer replacement (T1/T2/T3/T4) is expected to be completed in 2024.
- Main TS transformer replacement (T3/T4) is expected to be completed in 2024.
- John TS transformer replacement (T5/T6) is expected to be complete in 2025. Transformer T1, T2 and T4 have been replaced in 2019-2021. The condition of transformer T3 and the 115 kV breakers are reviewed and considered in fair condition; no replacement in the near/medium term is needed.
- Circuits C5E/C7E underground cable replacement between Esplanade TS and Terauley TS is underway and expected to be completed in 2026.

Other near/medium-term needs identified in the previous RP cycle and the new near/medium-term needs identified in this NA are:

Identified in the previous RP cycle	Identified in this NA
<u>Line Capacity</u> (Refer to section 7.2 for more details) • Richview to Manby 230 kV Corridor [2026] • Manby to Riverside Jct 115 kV Corridor [2026, with a line upgrade expected by 2028] <u>Transformers / Autotransformers Requiring Replacement</u> (Refer to section 7.1 for more details) • Charles TS: T3/T4 [2026] • Duplex TS: T1/T2 [2026] • Scarboro TS: T23 [2027] • Fairchild TS: T1 [2028] • Bermondsey TS: T3/T4 [2029] • Manby TS: autotransformers T7, T9, and T12, and step-down transformer T13 [2029-2030] • Leslie TS: T1 [2030] <u>Transmission Lines Requiring Replacement</u> (Refer to section 7.1 for more details) • H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. 115 kV overhead section [2025] • L9C/L12C: Leaside TS to Balfour Jct. 115 kV overhead section [2027]	<u>Transformers / Autotransformers Requiring Replacement</u> (Refer to section 7.1 for more details) • Strachan TS: T14 & T13/T15 [2025, 2031] • Basin TS: T3/T5 [2027] • Scarboro TS: T23 [2027] • Fairchild TS: T3/T4 [2028] • Malvern TS: T3 [2029] • Manby TS: T14 [2029] • Duplex TS: T3/T4 [2031] <u>Load Restoration</u> (Refer to section 7.4) • Loss of C14L/C17L • Loss of C18R/P22R

The long-term needs that were identified in the previous RP cycle and this NA are [beyond 2031]:

Identified in the previous RP cycle	Identified in this NA (Potential)
<u>Station Capacity</u> • Fairbank TS • Sheppard TS • Strachan TS • Basin TS <u>Transformation Capacity</u> • Manby W TS • Leaside TS <u>Line Capacity</u> • Leaside TS to Wiltshire TS 115 kV Corridor	<u>Station Capacity</u> • Glengrove TS • Finch TS / Bathurst TS • Warden TS <u>Line Capacity</u> • Parkway TS to Richview TS 230 kV Corridor

7. RECOMMENDATIONS

The TWG's recommendations are as follows:

a) No further regional coordination is required for the following need:
- Asset renewal needs for replacing the major HV equipment as listed in the table below. These needs will be addressed directly by Hydro One and THESL to develop a preferred replacement plan giving consideration to "right-sizing";

b) Further assessment and regional coordination is required in the next phases of the RP cycle to review and/or develop a preferred plan for the follow needs:
- The line capacity need for the 115 kV corridor between Manby TS and Riverside Jct. Hydro One will initiate the development work for reconductoring the overhead line section; and
- The load restoration and long-term needs as listed in the following table.

<table>
<tr><th>Further Regional Coordination Not Required</th><th>Further Regional Coordination Required</th></tr>
<tr><td rowspan="2">Asset Renewal Needs (Stations):
• Strachan T14 & T13/T15
• Charles TS: T3/T4
• Duplex TS: T1/T2 & T3/T4
• Basin TS: T3/T5
• Scarboro TS: T23
• Fairchild TS: T1 & T3/T4
• Bermondsey TS: T3/T4
• Malvern TS: T3
• Manby TS: T7, T9, T12 autotransformers, T13/T14 step-down transformer
• Leslie TS: T1

Asset Renewal Needs (Lines):
• 115 kV H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. overhead section
• 115 kV L9C/L12C: Leaside TS to Balfour Jct. overhead section

Line Capacity Need:
• 230 kV Richview TS to Manby TS Corridor

Station Capacity Need:
• Fairbank TS
• Strachan TS</td><td>Line Capacity Need:
• 115 kV Manby TS to Riverside Jct. Corridor

Load Restoration:
• Loss of C14L/C17L
• Loss of C18R/P22R</td></tr>
<tr><td>Long-Term Needs:
• Sheppard TS – Station Capacity
• Basin TS – Station Capacity
• Glengrove TS – Station Capacity
• Finch TS / Bathurst TS – Station Capacity
• Warden TS – Station Capacity
• 230/115kV Manby W Autotransformers – Transformation Capacity
• 230/115kV Leaside TS Autotransformers – Transformation Capacity
• 230 kV Parkway TS to Richview TS Corridor – Line Capacity
• 115kV Leaside TS to Wiltshire TS Corridor – Line Capacity</td></tr>
</table>

This NA assessment does not include or consider the impact from the IESO's "Pathways to Decarbonization" report published on December 15, 2022. The electricity demand and new infrastructure need in the longer term could be substantially higher than anticipated and discussed in this report. The TWG recommends that this be assessed in the next phase of this RP cycle.

TABLE OF CONTENTS

List of Tables and Figures

1 INTRODUCTION

The second cycle of the Regional Planning (“RP”) process for the Toronto Region was completed in March 2020 with the publication of the Regional Infrastructure Plan (“RIP”) report.

The purpose of this Needs Assessment (“NA”) is to identify new needs in the region, reaffirm and update needs identified in the previous Toronto RP cycle, and recommend which needs require further assessment and regional coordination and which do not.

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

Table 1: Toronto Region TWG Participants

Company
Alectra Utilities Corporation
Elexicon Energy Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (“IESO”)
Toronto Hydro-Electric System Limited (“THESL”)
Hydro One Networks Inc. (Lead Transmitter)

2 REGIONAL ISSUE/TRIGGER

In accordance with the RP process, the RP cycle should be triggered at least once every five years. Considering these timelines, the third RP cycle was triggered for the Toronto Region.

3 SCOPE OF NEEDS ASSESSMENT

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

- Reaffirm and update needs/plans identified in the previous RP cycle;
- Identify any new needs resulting from this assessment;
- Recommend which need(s) require further assessment and regional coordination in the next phases of the RP cycle; and

- Recommend which need(s) that do not require further regional coordination (i.e. can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle).

The TWG may identify additional needs during the next phases of the RP process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), and/or RIP based on updated information available at that time.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Toronto Region covers 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 includes the City of Toronto, which is the largest City in Canada and the fourth largest in North America. Please see Figure 1 for the Toronto Region map. Electrical supply to this 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 seventeen 230/27.6kV step-down transformer stations. The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS) and sixteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The region is also supplied locally by Portlands Energy Centre, a 550 MW combined-cycle power generating station. The sum of 2021 non-coincident summer station peak load of the Region was about 4,850 MW.

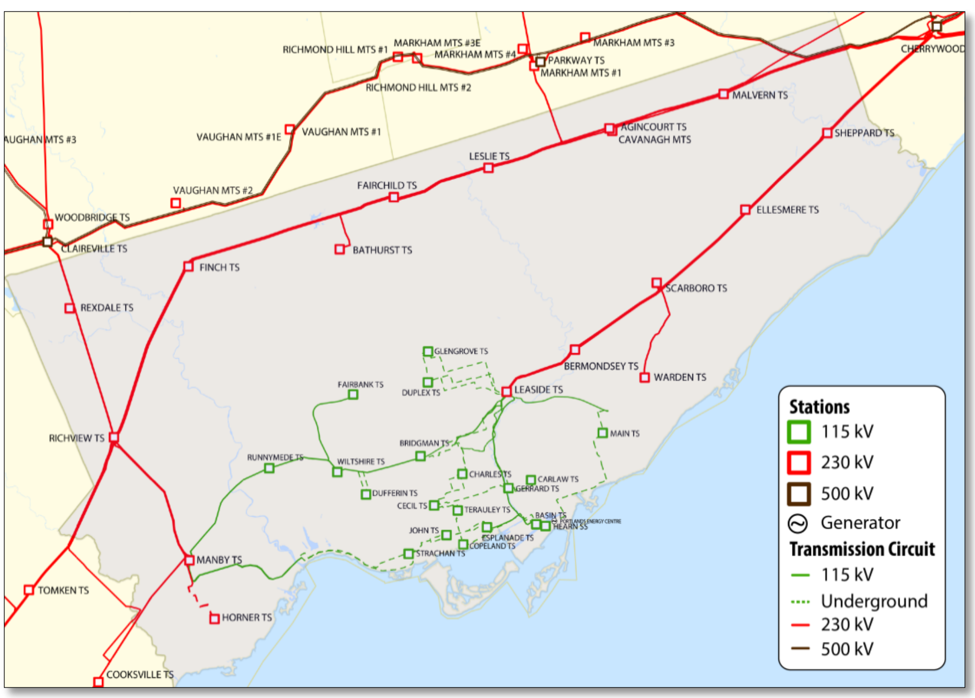

Figure 1: Toronto Region Map

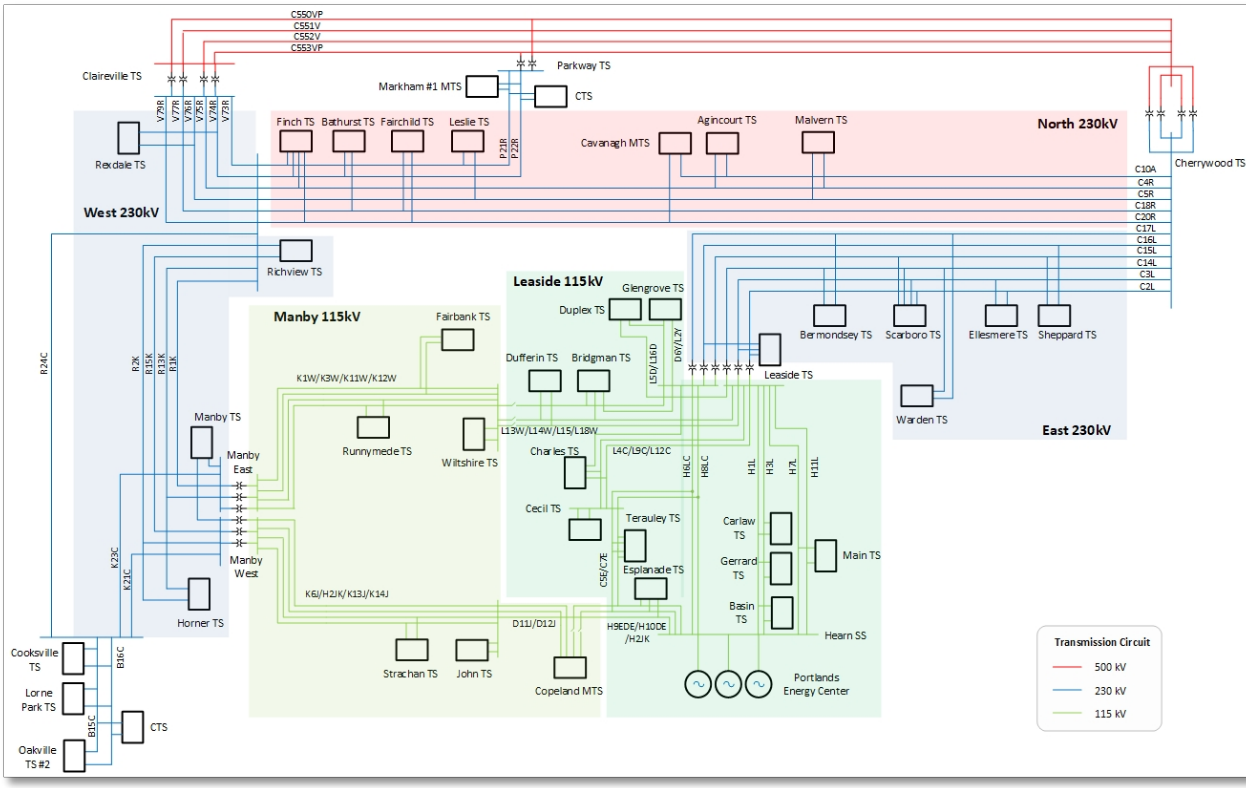

Figure 2: Toronto Region – Single Line Diagram

5 INPUTS AND DATA

TWG 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 for all supply stations in the Toronto Region;
- Known capacity and system reliability needs, operational issues, and/or major HV transmission equipment requiring replacement over the study period; and
- Planned/foreseen transmission and distribution investments that are relevant to the Toronto RP process.

The information provided was the most recent information available and provided at the time of the NA phase. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in October 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the RP process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP) (in cases where it has been produced by the municipality and the information can be translated by the LDC into the impact on peak demand). Accordingly, the OEB

RPPAG also recently developed a guideline called “Improving the Electricity Planning Process in Ontario: Enhanced Coordination between Municipalities and Entities in the Electricity Sector”, which lists the key MEP/CEP outputs to improve LDC load forecasts going forward. THESL has been closely coordinating with developers, provincial agencies and the City of Toronto on energy plans impacting various sections of the grid across the Toronto region. This NA report is recommending that further engagement be undertaken during the next phase of the RP cycle.

Also, it is important to be noted that, the IESO has just published the “Pathways to Decarbonization” on December 15, 2022, which evaluates a moratorium on the procurement of new natural gas generating stations in Ontario and develops an achievable pathway to decarbonization in the electricity system. It recommends that development work for priority transmission investments be identified to support decarbonization in the RP process. With this increasing focus on decarbonization and electrification, the electricity demand and new infrastructure need in the longer term could be substantially higher than anticipated and discussed in this NA report. The TWG recommends that the “Pathways to Decarbonization” report and its subsequent impact on the need and/or the timing for additional electrical supply facilities in the Toronto Region be considered and assessed in the next phase of this RP cycle.

6 ASSESSMENT METHODOLOGY

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

Information gathering included:

- Load forecast: The LDCs provided their load forecast for all the stations supplying their loads in the Toronto Region for the 10-year study period. The IESO provided a Conservation and Demand Management (“CDM”) forecast and Distributed Generation (“DG”) contract information for the Toronto Region. The region’s extreme summer non-coincident peak gross load forecast for each station were prepared by applying the growth rates from the LDC load forecast to the actual 2021 summer peak extreme weather corrected loads. The extreme summer weather correction factor was provided by Hydro One. The net extreme weather summer load forecast was produced by reducing the gross load forecast for each station by the percentage CDM from the IESO for that station. It is to be noted that even though the IESO did not have information on new and contracted DG coming into service within the planning horizon, THESL has assumed the existing DGs are to remain in-service in the base year when developing their load forecast. The extreme summer weather corrected net non-coincident peak and coincident peak load forecasts for the individual stations in the Toronto region are given in Appendices A-1 and A-2;
- Relevant information regarding system reliability and operational issues in the region;
- List of major HV transmission equipment planned and/or identified to be replaced based on asset condition assessment, and relevant for RP purposes. The scope of equipment considered is given in Section 7.1.

A technical assessment of needs was undertaken based on:

- Station capacity and transmission adequacy assessment;
- System reliability and operational considerations;
- Asset renewal for major HV transmission equipment requiring replacement with consideration to “right-sizing”; and
- Sensitivity analysis to capture uncertainty in the load forecast (which does not consider the impact from the “Pathways to Decarbonization” report published by the IESO on December 15, 2022, but will be assessed in the next phase of this RP cycle).

The following other assumptions are made in this report.

- The study period for this NA is 2022-2031.
- Transmission system adequacy is assessed by using coincident peak loads in the area.
- 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 (LV) capacitor banks and 95% lagging power factor for stations having LV capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

7 NEEDS

This section identifies any new needs in the Toronto Region, and reaffirms and provides an update on the near, medium, and long-term needs already identified in the previous RIP.

Needs that were identified in the previous RP cycle with associated projects recently completed or currently underway were reaffirmed and are briefly described below with relevant updates. These are not further discussed in later sections of this report.

- Second DESN at Horner TS and refurbishment projects at Runnymede TS (T3/T4), Sheppard TS (T3/T4), and Strachan TS (T12) were completed in 2021-2022.
- Copeland MTS phase 2 is expected to be in-service in 2024 to address the station capacity need.
- Bridgman TS transformer replacement (T11/T12/T13/T14) is expected to be completed in 2024.
- Fairbank TS transformer replacement (T1/T2/T3/T4) is expected to be completed in 2024.
- Main TS transformer replacement (T3/T4) is expected to be completed in 2024.
- John TS transformer replacement (T5/T6) is expected to be completed in 2025. Transformer T1, T2 and T4 were replaced in 2019-2021. Based on asset condition assessment, transformer T3 and the 115 kV breakers are not recommended for replacement in the near/medium term.
- Circuits C5E/C7E underground cable replacement between Esplanade TS and Terauley TS is underway and expected to be completed in 2026. A 2.5 km tunnel between Esplanade TS and Terauley TS is to be built.

The planned in-service year for the above underway projects is tentative and is subject to change.

All the other near/medium-term needs and long-term needs are summarized in Table 2 and Table 3 respectively. The load restoration need was also reviewed and is discussed in Section 7.4.

Table 2: Near/Medium Term Needs Identified in Previous RIP [(1)] and/or this NA

Type of Needs	Near/Medium-Term Needs	NA Section	Timing	Recommended Plan / Status	RIP Report Section
Line Capacity	Richview TS to Manby TS 230 kV Corridor	7.2.1	2026	Project in estimate phase.	7.5
Line Capacity	Manby TS to Riverside Jct 115 kV Corridor	7.2.2	2028 [(3)]	Timing is advanced to 2026.	7.9.5
Asset Renewal Needs (Stations) [(2)]	Strachan TS: Transformers T14 & T13/T15	7.1.1	2025 2031	• T14 requires replacement with higher rated unit. • T13/T15 need replacement with higher rated unit in medium term.	NEW
Asset Renewal Needs (Stations) [(2)]	Charles TS: Transformer T3/T4	7.1.2	2026	T3/T4 require replacement with higher rated units.	2nd cycle NA
Asset Renewal Needs (Stations) [(2)]	Duplex TS: Transformers T1/T2 & T3/T4	7.1.3	2026 2031	• T1/T2 require replacement with higher rated units. • T3/T4 need replacement with higher rated unit in medium term.	2nd cycle NA NEW
Asset Renewal Needs (Stations) [(2)]	Basin TS: Transformers T3/T5	7.1.4	2027	T3/T5 require replacement with higher rated units.	NEW / 7.9.4
Asset Renewal Needs (Stations) [(2)]	Scarboro TS: Transformer T23	7.1.5	2027	T23 requires replacement with like-for-like unit.	NEW
Asset Renewal Needs (Stations) [(2)]	Fairchild TS: Transformer T1 & T3/T4	7.1.6	2028	T1 and T3/T4 require replacement with like-for-like units.	2nd cycle NA (T1), NEW (T3/T4)
Asset Renewal Needs (Stations) [(2)]	Bermondsey TS: Transformers T3/T4	7.1.7	2029	T3/T4 require replacement with like-for-like units.	7.7
Asset Renewal Needs (Stations) [(2)]	Malvern TS: Transformer T3	7.1.8	2029	T3 requires replacement with like-for-like unit.	NEW
Asset Renewal Needs (Stations) [(2)]	Manby TS: Autotransformers (T7, T9, T12), Step-down transformer (T13/T14)	7.1.9	2029 2030	• T13/T14 need replacement with similar unit per current standard. • T7/T9/T12 need replacement with similar unit per current standard. • 230 kV breakers are in fair condition; will not be replaced in the near term.	7.6, NEW (T14)
Asset Renewal Needs (Stations) [(2)]	Leslie TS: Transformer T1	7.1.10	2030	T1 requires replacement with similar unit per current standard.	2nd cycle NA
Asset Renewal Needs (Lines) [(2)]	H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. overhead section	7.1.11	2025	Development and estimate work to initiate in 2023.	7.2
Asset Renewal Needs (Lines) [(2)]	L9C/L12C: Leaside TS to Balfour Jct. overhead section	7.1.12	2027	Development and estimate work to initiate in 2023.	7.3

(1) Includes needs identified in the previous RIP that do not have projects in execution yet.
(2) The replacement/refurbishment scope, timing, and prioritization are based on the best available information at the time, and are subject to change.
(3) Earliest in-service of reconductoring the overhead line K13J/K14J is expected to be around 2028 if the development and estimate work is to be initiated in 2023.

Table 3: Long-Term Needs Identified in Previous RIP and/or this NA

Type of Needs	Long-Term Needs	NA Section	Timing (2nd Cycle RIP)	Description / Update	RIP Report Section
Station Capacity	Fairbank TS	7.3.1	2030-2035	New Runnymede DESN and the underway transformers replacement at Fairbank TS will provide relief.	7.9.1
	Sheppard TS	7.3.2	2030-2035	Consideration may be given to utilizing the idle winding on transformers T1/T2.	7.9.2
	Strachan TS	7.3.3	2030-2035	Transformer T12 has been replaced with a 60/100 MVA unit. Station capacity will increase after T14 is replaced by 2025 and T13/T15 are replaced in the medium term.	7.9.3
	Basin TS	7.3.4	2030-2035	Station capacity will increase when transformers T3/T5 will be replaced with 60/100 MVA units by 2027.	7.9.4
	Glengrove TS	7.3.5	Beyond 2031	Glengrove TS is almost at capacity in 2031. The transformer replacement with higher rated units at Duplex TS will provide relief.	NEW
	Finch TS / Bathurst TS	7.3.6	Beyond 2031	Total load at Finch TS and Bathurst TS is almost reaching the combined station capacity in 2031. To be managed by load transfer between DESNs and nearby stations at distribution level in the near/medium term.	NEW
	Warden TS	7.3.7	Beyond 2031	Load demand near Warden TS exceeds its capacity from 2024. To be managed by load transfer to Scarboro TS at distribution level in the near/medium term.	NEW
Transformation Capacity	Manby W TS Autotransformers (T12)	7.3.8	2030-2035	Restricted by the lowest rated autotransformer unit T12. This unit is planned to be replaced by 2030 and will provide relief to this constraint.	7.9.6
	Leaside TS Autotransformers (T16)	7.3.9	2035-2040	Autotransformer T16 is potentially overloaded following circuit C14L, C15L, or C17L contingency, assuming that two of the three units at Portlands Energy Centre GS are out-of-service, and total plant generation is 160 MW. Post-contingency control action is currently available to resolve this issue by transferring Dufferin TS to Manby supply if needed.	7.9.8
Line Capacity	230 kV Parkway TS to Richview TS Corridor	7.3.10	Beyond 2031	Some sections of the 230 kV circuits P21R and P22R near the Parkway TS end are approaching limit by 2031. The baseline forecast does not reflect several customers that show interest in connecting new load near the Steeles / Hwy 404 area. This need may arise sooner.	NEW
	115 kV Leaside TS to Wiltshire TS Corridor		2035-2040	The Bayview Jct. x Balfour Jct. underground section of the 115 kV circuit L15 is potentially overloaded in the long term.	7.9.7

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second RP cycle, Hydro One and the TWG have identified some new major HV equipment replacement needs over the next 10 years in the Toronto Region, as shown in Table 4 below. These needs are determined by asset condition assessment, which is based on a range of considerations such as equipment deterioration; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. The scope, timing, and prioritization of these replacement needs are based on the current available information and are subject to change.

The major HV transmission equipment considered in this assessment includes the following:

- 230 / 115 kV autotransformers;
- 230 kV and 115 kV load serving step-down transformers;
- 230 kV and 115 kV breakers where:
  - Replacement of six breakers or more than 50% of station breakers, the lesser of the two; and
- 230 kV and 115 kV transmission lines requiring refurbishment where:
  - Leave to Construct (i.e., Section 92) approval is required for any alternatives to like-for-like.

The asset renewal assessment considers options for "right-sizing" the equipment such as:

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 the load to other existing facilities;
5. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement); and
6. Replacing equipment with higher ratings and built to current standards.

Table 4: New Major HV Transmission Equipment Replacement Needs Identified in this NA

Station	Timing	Need Description
Strachan TS: Transformers T14 & T13/T15	2025* 2031	T14 requires replacement in the medium term with higher rated unit. T13/T15 need replacement in the medium term with higher rated units.
Basin TS: Transformers T3/T5	2027	T3/T5 require replacement in the near term with higher rated units.
Scarboro TS: Transformer T23	2027	T23 requires replacement in the near term with like-for-like unit.
Fairchild TS: Transformer T3/T4	2028	T3 requires replacement in the medium term with like-for-like unit.
Malvern TS: Transformer T3	2029	T3 requires replacement in the medium term with like-for-like unit.
Manby TS: Transformer T14	2029	T14 need replacement in the medium term with similar unit per current standard.
Duplex TS: Transformers T3/T4	2031	T3/T4 require replacement in the medium term with higher rated units.

* Need date is advanced to support planned work at the other DESN in Strachan TS.

The newly identified major HV transmission equipment replacement need in this NA will be discussed in detail in the following subsections. The previously identified asset renewal needs from the last RP cycle, for which project execution has not yet been initiated, will also be reviewed and discussed in the following. The TWG recommends continuation of addressing all the identified needs for the Toronto Region as per the recommended plan described in each subsection. THESL has also confirmed that there is no plan to replace any major HV transmission equipment under its under ownership over the study period.

For the 115-13.8 kV 45/75 MVA step-down transformers where replacement is required, and upsizing is recommended, the largest standard size (60/100MVA) units for this voltage class will be used. The 115-13.8 kV 60/100 MVA transformer has two secondary windings and each winding has an LTR of 72 MVA which matches the 3000 A or 72 MVA metal clad switchgear that THESL has standardized on and used at 13.8 kV. Even if a larger custom size transformer is procured, no additional station capacity will be provided as it is limited by the metal clad switchgear. The estimated incremental cost of upsizing a 45/75 MVA unit to a 60/100 MVA unit is approximately $300k based on current dollars.

7.1.1 Strachan TS

Strachan TS comprises two DESN units, T12/T14 (T12 replaced in 2022: 60/100 MVA; T14: 45/75 MVA) and T13/T15 (45/75 MVA), having a summer 10-Day LTR of 171 MW. The station’s 2021 actual non-coincident summer peak load was about 135 MW and is forecasted to be approximately 140 MW (net adjusted for extreme weather) in 2031.

Transformer T14 is currently about 47 years old and requires replacement in the medium term based on asset condition assessment. It is planned to replace it with a 60/100MVA unit as the companion transformer T12 was recently replaced with a 60/100 MVA unit thereby increasing the station capacity. Transformers T13 and T15 are currently about 40 years old and will also require replacement in the medium term based on their condition. The station capacity will be further increased after they are replaced with 60/100 MVA units. This will provide the additional capacity required to support the transformers and switchgear replacement work planned for Strachan TS in the medium term and accommodate the long-term growth and development need anticipated in the area subsequent to the Ontario Line subway project. Replacing the transformers with similar size equipment is not recommended since upgrading later within the lifetime of the transformer due to eventual load growth will be significantly more costly. It should also be noted that increasing capacity, as opposed to maintaining it, is a more resilient option as it provides additional flexibility during emergency conditions or any planned outages through load transfers. With new T12 installed this year, replacing the remaining three transformers with 60/100 MVA units will provide an additional station capacity of approximately 98 MVA at Strachan TS.

Based on the above, the TWG recommends that transformers T14, T13 and T15 be replaced with 60/100MVA units. Hydro One and THESL will coordinate the replacement plan for these transformers. The planned in-service date is 2025 for T14 and 2031 for T13 and T15.

7.1.2 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 211 MW. The station's 2021 actual non-coincident summer peak load was about 127 MW and is forecasted to be approximately 165 MW (net adjusted for extreme weather) in 2031. Transformers T3 and T4 are currently about 55 years old and require replacement based on asset condition assessment.

The load at Charles TS is forecasted to be almost 80% 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 about 80%, 65%, and 80% in the medium term.

As discussed in the 2nd cycle NA, the TWG recommends that transformer T3 and T4 be replaced with 60/100MVA units because this is the most cost-effective option that addresses the replacement need and maintains reliable long-term supply to the existing and potential customers in the area. Hydro One and THESL are coordinating this replacement work and the planned in-service date is 2026.

7.1.3 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 128 MW. The station's 2021 actual non-coincident summer peak load was about 88 MW and is forecasted to be approximately 112 MW (net adjusted for extreme weather) in 2031.

Transformers T1 and T2 are currently about 54 years old and require replacement in the near term based on asset condition assessment. As discussed in the second cycle NA, replacing T1/T2 with 60/100 MVA units is recommended to allow for effective planning for long-term electricity needs, reliability and system resiliency. The forecast developed in this NA reaffirms this recommendation as the load at Duplex TS and its nearby stations Bridgman TS and Glengrove TS are to be over 85%, 80% and 95% of their station LTR respectively in 2031.

Transformer T3 and T4 are currently about 46-48 years old and require replacement in the medium term based on asset condition assessment. With the same reasons discussed above and the growing demand in the area, the TWG recommends that these transformers be replaced with 60/100 MVA units.

Hydro One and THESL will coordinate the replacement plan for transformers T1/T2 and T3/T4. The current planned in-service dates are 2026 and 2031 respectively.

7.1.4 Basin TS

Basin TS comprises one DESN unit, T3/T5 (45/75 MVA), having a summer 10-Day LTR of 88 MW. The station's 2021 actual non-coincident summer peak load was about 57 MW and is forecasted to be approximately 85 MW (net adjusted for extreme weather) in 2031.

Transformers T3 and T5 are currently about 39 years old and require replacement in the near term based on asset condition assessment. The load at Basin TS is forecasted to be over 95% of its station LTR in 2031.

The load at its nearby stations Carlaw TS, Gerrard TS and Esplanade TS is also forecasted to be over 70-85% of their station LTR by 2031.

The City of Toronto is planning to re-develop the East Harbour land which is located in the Lakeshore and Don Roadway area in the near and medium term, as well as the Port Lands area in the longer term. These areas may see additional load in the longer term, beyond what is currently forecast in this NA. The scale and timing of additional load will depend upon the City's plan. However, the City's current re-development plans may impact the continued operation of Basin TS and several high voltage lines in their current locations in the Port Lands area. If implemented, this would significantly impact both Hydro One infrastructure and THESL infrastructure within and outside of Basin TS. No potential sites for a replacement transformer station or high voltage line routes have been identified by the City at this time. Hydro One and THESL have requested the City to revise its plans to avoid the conflicts with Basin TS and high voltage lines, and joined others in a legal appeal of the City's land plans. In December 2020, the appeal was settled provided that all parties will continue to reassess different options with and without the relocation or reconfiguration of the electricity infrastructure in the Port Lands area. There is no update or change in status at this time, but Hydro One and THESL will provide updates to the TWG as information becomes available.

Based on asset condition assessment of the existing transformers at Basin TS, the TWG recommends that transformers T3/T5 be replaced with 60/100 MVA units to address the replacement need and avoid any extended forced outages due to potential failure of these existing transformers. This will also provide an additional station capacity of approximately 46 MVA at Basin TS to help accommodate expected load growth in this area. Hydro One and THESL coordinate the replacement work.

The TWG also recommends that the long-term supply need in the Basin / Port Lands area be reviewed as part of the next phase in the RP process because of the uncertainty associated with the long-term growth plans as well as the potential impacts on the electricity infrastructure in this area resulting from the City's redevelopment plans. This is consistent with the finding and the recommendation from the previous RP cycle and as discussed in Section 7.3.4 of this report.

7.1.5 Scarboro TS

Scarboro TS comprises two DESN units, T21/T22 (75/125 MVA) and T23/T24 (75/125 MVA), having a summer 10-Day LTR of 340 MW. The station's 2021 actual non-coincident summer peak load was about 217 MW and is forecasted to be approximately 257 MW (net adjusted for extreme weather) in 2031.

Transformer T23 is currently about 48 years old and require replacement in the near term based on asset condition assessment. The load at Scarboro TS is forecasted to be over 75% of its station LTR in 2031. Its nearby stations Warden TS is forecasted to exceed its station capacity in the near term and need relief by transferring load to Scarboro TS. The load at other closest stations Bermondsey TS and Ellesmere TS is also forecasted to be about 80% and 85% of their station LTR by 2031.

Downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly costlier. 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 or any planned outages through load transfers. Therefore, downsizing T23 is not a viable option. Upgrading the transformer is also not an option since it is already at the maximum standard size.

The TWG has recommended that transformer T23 be replaced with the same type and size unit (75/125 MVA). Hydro One and THESL will coordinate the replacement plan for the transformer and the planned in-service date is 2027.

7.1.6 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 2021 actual non-coincident summer peak load was about 216 MW and is forecasted to be approximately 243 MW (net adjusted for extreme weather) in 2031. Transformers T1 is 52 years old but was rebuilt 36 years ago. The companion DESN transformer T2 failed and was replaced under emergency in 2017 with a similar 75/125 MVA unit. Transformers T3 and T4 in the other DESN are 39 years old. Transformers T1, T3 and T4 require replacement in the medium term based on asset condition assessment.

The load at Fairchild TS is forecasted to be over 70% of its LTR in the medium term. The load at the two closest stations, Bathurst TS and Leslie TS, is also forecasted to be about 95% and 90% of their respective LTR's in the medium term. Downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly costlier. 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 or any planned outages through load transfers. Therefore, downsizing the transformers at Fairchild TS and consolidating load within the station and/or with area stations is not a viable option given medium term load growth at these stations. Upgrading the transformers is also not an option since they are already at the maximum standard size.

Based on the above, the TWG recommends that transformers T1, T3 and T4 be replaced like-for-like. Hydro One and THESL will coordinate the replacement plan for these transformers. The planned in-service date is 2028.

7.1.7 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 2021 actual non-coincident summer peak load was about 153 MW and is forecasted to increase significantly in the near term due to new load customers in the area. The load is forecasted to be approximately 275 MW (net adjusted for extreme weather) in 2031. Transformers T3 and T4 are currently about 57 years old and require replacement in the near term based on asset condition assessment.

The load at Bermondsey TS is forecasted to be almost 80% of its LTR in the medium term. The load at the three closest stations, Scarboro TS, Warden TS, and Leaside TS is forecasted to be over 75%, 100%[1], and 67% respectively of their LTR's in the medium term.

As evaluated in the 2nd cycle RIP and reaffirmed in this NA, transformer T3 and T4 are to be replaced with similar type and size equipment as per current standard because this is the most cost effective option that addresses the replacement need and maintains reliable long-term supply to the customers in the area. The planned in-service date of this refurbishment work is 2029.

7.1.8 Malvern TS

Malvern TS comprises one DESN unit, T3/T4 (75/125 MVA), having a summer 10-Day LTR of 176 MW. The station's 2021 actual non-coincident summer peak load was about 110 MW and is forecasted to be approximately 119 MW (net adjusted for extreme weather) in 2031. Transformers T3 is currently 36 years old and requires replacement in the medium term based on asset condition assessment.

The load at Malvern TS is forecasted to be almost 70% of its LTR in the medium term. The load at the three closest stations, Agincourt TS, Cavanagh MTS, and Sheppard TS is forecasted to be over 60%, 90%, and 90% respectively of their LTR's in the medium term. Downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly costlier. 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 or any planned outages through load transfers. Therefore, downsizing the transformer at Malvern TS and consolidating load within the station and/or with area stations is not a viable option given medium term load growth at these stations.

Based on the above, the TWG recommends that transformer T3 be replaced with the same type and size unit (75/125 MVA). Hydro One and THESL will coordinate the replacement plan for this transformer. The planned in-service date is 2029.

7.1.9 Manby TS

Manby TS is a major bulk electric switching and autotransformer station in the Toronto region. Station facilities include the Manby West and Manby East 230 kV and 115 kV switchyards, six 230/115 kV autotransformers (T1, T2, T7, T8, T9, T12), and six 230/27.6 kV step-down transformers supplying three DESNs (T3/T4, T5/T6, T13/T14).

Three of the autotransformers, T7, T9, and T12, and two of the step-down transformers, T13 and T14, are close to 55 years old and require replacement in the medium term based on asset condition assessment. It is to be noted that T14 was not identified as a candidate for replacement in the previous RP cycle. The autotransformers continue to be critical to the load supply to the downtown and west Toronto area and will

[1] The net demand at Warden TS exceeds its station LTR by 2024. THESL will manage the station overload by transferring some load to Scarboro TS in the near/medium term.

be replaced with similar 250 MVA units, consistent with recommendations from previous RP cycle. The expected in-service date for the autotransformer replacement is 2030.

The total summer 10-Day LTR of the six step-down transformers is 226 MW. The station's 2021 actual non-coincident summer peak load was about 237 MW which exceeds the station capacity and will be relieved in the near and medium term by transferring load to the second DESN at Horner TS recently built. The total DESN load at Manby TS, after the load transfer, is forecasted to be approximately 204 MW (net adjusted for extreme weather) in 2031, i.e. over 90% of its LTR in the medium term. Therefore, the TWG recommends transformers T13 and T14 (56/93 MVA units, non-standard size) be replaced with the current standard size units (75/125 MVA units) to address the replacement need and maintain reliable long-term supply to the customers in the area. This will potentially increase the station LTR by approximately 60 MVA. Hydro One and THESL will coordinate the replacement plan for these transformers. The planned in-service date of this refurbishment work is 2029.

Previously, the 230 kV oil breakers were considered as candidates for replacement. Since then, the condition of these breakers has been reviewed and based on this assessment, they are not required for replacement in the near or medium term. Hydro One will continue to monitor the condition of these breakers and coordinate the future replacement plan with the phase 2 work of the Richview TS x Manby TS 230 kV Corridor Upgrade project as described in Section 7.2.1 of this report. Updates will be provided to the TWG in the next RP cycle as required.

7.1.10 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 323 MW. The station's 2021 actual non-coincident summer peak load was about 221 MW and is forecasted to be approximately 249 MW (net adjusted for extreme weather) in 2031. Transformer T1 is currently about 59 years old and require replacement based on asset condition assessment. The companion DESN transformer T2 is currently 25 years old and does not require replacement in the near or medium term.

It should be noted that transformers T1 and T2 are non-standard units with dual LV voltages (230-27.6-13.8 kV 75/125 MVA units). The 13.8 kV load that are currently supplied from Leslie TS will be diminished and the 13.8 kV supply will not be needed from Leslie TS. Excluding the capacity for the 13.8kV winding, the total station LTR for the 27.6kV load is about 280 MW. The 27.6kV load at Leslie TS will be at almost 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 70%, 90%, and 60% respectively of their LTR's in the medium term. THESL is also anticipating additional new load connection in the longer term at Leslie TS and Agincourt TS.

Based on the above and consistent with the recommendation from the last NA, the TWG recommends that transformer T1 be replaced with a standard unit of same size without dual LV voltages (i.e. a 230-27.6-27.6 kV 75/125 MVA unit). Hydro One and THESL will coordinate the replacement plan for this transformer. When more capacity is required at Leslie TS, the companion transformer T2 can be replaced with the same

230-27.6-27.6 kV 75/125 MVA unit to provide an increase of approximately 70 MVA for the 27.6 kV supply capacity. The planned in-service date for transformer T1 is 2030.

7.1.11 Overhead Transmission Line H1L/H3L/H6LC/H8LC

The 115 kV circuits H1L/H3L/H6LC/H8LC provide connections between Leaside TS, Hearn SS, and Cecil TS, and supply transformer stations in the eastern part of central Toronto including Gerrard TS, Carlaw TS, and Basin TS. Based on their asset condition, conductors along the overhead section between Leaside 34 Jct. and Bloor St. Jct. (about 2 route km) are required to be replaced in the near term.

As recommended by the TWG from the previous RIP, the conductor in this overhead section will be replaced with largest size possible conductor while retaining existing tower structures. The expected in-service date for this line replacement work is around 2025.

7.1.12 Overhead Transmission Line L9C/L12C

The 115 kV circuits L9C/L12C provide connections between Leaside TS and Cecil TS, and supply to central downtown area including Charles TS and Cecil TS. The overhead section of this 115 kV double-circuit line between Leaside TS and Balfour Jct. (about 3.6 route km) is over 90 years old and require replacement in the near term.

As recommended by the TWG from the previous RIP, the conductor in this overhead section will be replaced with largest size possible conductor while retaining existing tower structures. The expected in-service date for this line replacement work is around 2027.

7.2 Station and Transmission Capacity Needs in the Near / Medium Term

The Station and Transmission supply capacities have been reviewed. No near or medium-term station capacity need has been identified in the Toronto region. However, two transmission line capacity needs are identified below during the study period of 2022 to 2031.

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

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto. Along this corridor there are two double-circuit 230 kV lines R1K/R2K and R13K/R15K. Together with circuit R24C between Richview TS and Cooksville TS, this corridor also supplies the load in the southern Mississauga and Oakville areas via Manby TS. The need and options to increase transfer capability of this transmission corridor to support the continuous load growth in these areas has been identified and discussed in the past RP cycles. This need was also reaffirmed in an IRRP addendum done in 2021.[2]

[2] The IRRP addendum for the Richview TS x Manby TS Circuit Upgrade need has not been published or shared outside of the TWG yet. However, since it was just reviewed last year, this need is not to be re-evaluated in this NA.

As previously documented, the recommendation is to proceed with:

Phase 1: Rebuilding the existing idle 115 kV overhead line on the transmission corridor between Richview TS and Manby TS to 230 kV standards. The new line will operate in parallel with the existing four 230 kV circuits from Richview TS to Manby TS, which will initially be reconfigured to create two "supercircuits" R2K and R15K. This configuration avoids the need to build new terminations and new breakers at Manby TS. This project is currently in estimate and public consultation phase. The planned in-service date is 2026.

Phase 2: Unbundling the "supercircuits" with one new circuit connected to Manby West and one to Manby East with new termination installed at Manby TS. At Richview TS, the new circuits will be tapped to existing 230 kV circuits V73R and V79R from Claireville TS. This configuration allows Richview TS to be bypassed and permits continued supply to Manby TS should there be an emergency at Richview TS. The timing of Phase 2 will be planned to coincide with Manby TS 230kV breakers replacement work when the time comes. As discussed in Section 7.1.9 of this report, the 230 kV breakers at Manby TS are currently in good condition and not planned to be in replaced in the coming 10 years. Their condition will be monitored and this phase 2 work will be coordinated with the replacement work. Updates will be provided to the TWG in the next RP cycle as required.

7.2.2 Manby TS x Riverside Junction 115 kV Corridor – Line Capacity

The 115 kV transmission corridor between Manby TS and John TS comprises four circuits K13J, K14J, K6J and H2JK, and provides supply to Downtown Toronto via three transformer stations John TS, Strachan TS and Copeland MTS. The 2021 actual total coincident summer peak load of these stations was about 370 MW and is forecasted to be approximately 513 MW and 500 MW (net adjusted for extreme weather) in 2026 and 2031 respectively. This corridor also provides backup supply to other stations that are normally connected to the Leaside / Hearn subsystem, such as Esplanade TS and Terauley TS.

The 7 km overhead section of the circuits K13J/K14J between Manby TS and Riverside Jct., as shown in Figure 3, is potentially overloaded under the contingency of the loss of the other circuits on this corridor. This need was identified as a long-term need (2030-2035) in the previous RIP. However, the new forecast in this NA has reflected the load demand increase from the Ontario Line subway and other residential and commercial development projects expected in the near term at Copeland MTS and John TS, and therefore this need is advanced to 2026.

The companion overhead line K6J/H2JK was upgraded in 2000 and currently has a higher ampacity rating than the K13J/K14J line. The capacity of this corridor could potentially be increased by approximately 100 MVA if the overhead section of the circuits K13J/K14J between Manby TS and Riverside Jct. is upgraded. A line upgrade project of this scope may take over 5-6 years to carry out the required work before it is in-service which includes, but not limited to, the development and estimate work, public consultation, environmental assessment, internal and external approvals, construction, outage planning and commissioning work. The earliest in-service date of the reconductoring work could be in 2028 if the development and estimate work is to begin in 2023. It is also to be noted that extended outages may be required to reconductor the line. As a result of limited load transfer capability between the Manby West and Leaside / Hearn subsystems, obtaining the said outages to complete this work could be very challenging, and worsen further as the load increases in these areas.

Considering the long timeline of the corridor upgrade and that more load could potentially be affected during construction, the TWG recommends Hydro One proceed on the development work for reconductoring the circuits K13J/K14J to higher ampacity conductors without replacing the existing towers. This need will continue to be reviewed as part of the next phase of this RP cycle.

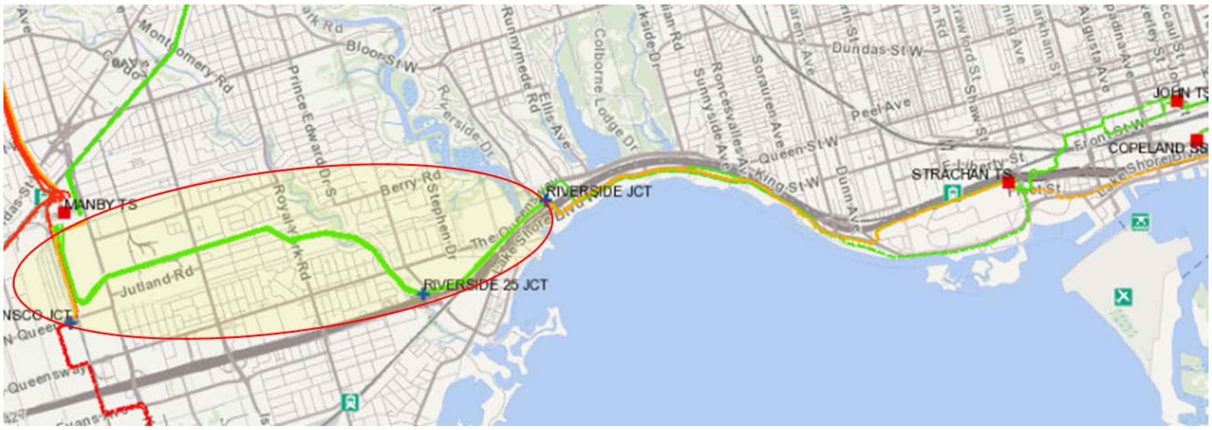

Figure 3: 115 kV Corridor between Manby TS and John TS (overhead section is circled)

7.3 Long-Term Capacity Needs

This section describes the long-term capacity needs identified from the previous RIP as well as the potential ones that are observed from this NA review.

This NA focuses on assessing and identifying the needs in the Toronto Region within the 10-year timeframe (up to 2031). It is observed that there are some transformer stations and 230 kV circuits that are approaching their limits by 2031 as listed in Table 5 below. This finding is consistent with the information shared by the TWG that the Toronto Region is about to embark on a period of growth over the short and medium term driven by electrification, and that the large-scale development and customer connection projects are expected in several areas within the Toronto Region in the coming years.

Table 5: Potential Long-Term Capacity Needs to be Further Assessed

Station / Circuit	Need Description
Glengrove TS	Total net demand is forecasted to be about 98% of station LTR by 2031.
Finch TS / Bathurst TS	Total net demand at Finch TS and Bathurst TS is forecasted to be about 100% and 97% of station LTR respectively by 2031.
Warden TS	The net demand at Warden TS exceeds its station LTR by 2024. THESL will manage the station overload by load transfer to Scarboro TS in the near/medium term.
Parkway TS to Richview TS 230 kV Corridor (P21R/P22R)	Markham #1 Jct. x Leaside Jct. section of the overhead 230 kV circuits P21R and P22R, connecting Parkway TS and Richview TS, is approaching limit by 2031.

These potential long-term capacity needs will be further reviewed in the next phases of this RP cycle.

7.3.1 Fairbank TS – Station Capacity

The long-term capacity need at Fairbank TS was identified in the previous RIP. The load at Fairbank TS was expected to exceed LTR within the 2030-2035 time period.

Fairbank TS comprises two DESN units, T1/T3 and T2/T4 (all 115/27.6 kV 50/83 MVA units), having a summer 10-Day LTR of 182 MW. The station's 2021 actual non-coincident summer peak load was about 197 MW. The excess load is planned to be transferred to Runnymede TS where a new DESN was built in 2019 and the old DESN was rebuilt in 2021. The Fairbank TS load is forecasted to be approximately 170 MW (net adjusted for extreme weather) or 93% of its station LTR in 2031. The transformer replacement work at Fairbank TS (T1/T2/T3/T4) is also underway with planned in-service date of 2024. The station LTR at Fairbank TS is expected to increase after the transformer replacement and provide some additional capacity. Together with the new and refurbished DESNs recently built at Runnymede TS, it is expected that the existing facilities will be adequate to supply the long-term growth in the area. The TWG recommends the loading be monitored and reviewed in the next RP cycle.

7.3.2 Sheppard TS – Station Capacity

The long-term capacity need at Sheppard TS was identified in the previous RIP. The load at Sheppard TS was expected to exceed LTR within the 2030-2035 time period.

Sheppard TS comprises two DESN units, T1/T2 (75/125 MVA units with idle winding) and T5/T6 (50/83 MVA units), having a summer 10-Day LTR of 204 MW. The station's 2021 actual non-coincident summer peak load was about 167 MW, and is forecasted to be approximately 187 MW (net adjusted for extreme weather) or 92% of its station LTR in 2031. Consideration may be given to utilizing the idle winding on transformers T1/T2. The TWG recommends the Sheppard TS loading be monitored and reviewed in the next phases of this RP cycle.

7.3.3 Strachan TS – Station Capacity

The long-term capacity need at Strachan TS was identified in the previous RIP. The load at Strachan TS was expected to exceed LTR within the 2030-2035 time period.

As discussed in Section 7.1.1, the transformer T12 at Strachan TS has been replaced recently with a 60/100 MVA unit. The station capacity at Strachan TS will increase after the transformer T14, and T13/T15 are also replaced with 60/100MVA units. This will provide adequate capacity to accommodate the long-term growth. The TWG recommends the loading be monitored and reviewed in the next RP cycle.

7.3.4 Basin TS – Station Capacity

The long-term capacity need at Basin TS was identified in the previous RIP. The load at Basin TS was expected to exceed LTR within the 2030-2035 time period.

As discussed in Section 7.1.4, the load at Basin TS is forecasted to be over 95% in 2031 and expected to increase further in the longer term due to the development plan in the Port Lands area as well as the East Harbor area. The transformers T13/T15 (45/75 MVA units) require replacement in the near term based on asset condition assessment. The TWG recommends that Hydro One and THESL coordinate and initiate the development work for replacing the transformers T3/T5 with 60/100 MVA units, and that the long-term supply need in the Basin / Port Lands area be reviewed as part of the next phase in the RP process. This will include consideration of the uncertainty associated with the long-term growth plans as well as the potential impacts on the electricity infrastructure in this area resulting from the City's redevelopment plans. This is consistent with the finding and the recommendation from the previous RP cycle.

7.3.5 Glengrove TS – Station Capacity

Glengrove TS comprises two DESN units, T1/T3 and T2/T4 (all 25/42 MVA units), having a summer 10-Day LTR of 88 MW. The station's 2021 actual non-coincident summer peak load was about 47 MW and is forecasted to be approximately 86 MW (net adjusted for extreme weather) or 98% of its LTR in 2031.

As discussed in Section 7.1.3, its closet station Duplex TS also has two DESN units, T1/T2 (45/75 MVA) and T3/T4 (45/75 MVA), having a summer 10-Day LTR of 128 MW. The load at Duplex TS is forecasted to be approximately 112 MW (net adjusted for extreme weather) or 88% of its LTR in 2031. The transformers T1/T2 and T3/T4 require replacement in the near and medium term. The TWG has recommended that these transformers be replaced with 60/100 MVA units to provide additional capacity in this area, and that the Glengrove TS and Duplex TS loading be monitored and reviewed in the next phases of this RP cycle.

7.3.6 Finch TS / Bathurst TS – Station Capacity

THESL has identified an emerging load growth in the Northwest Toronto area near Finch TS and Bathurst TS due to re-development plan in the Downsview area located in the Keele and Sheppard area.

Finch TS comprises two DESN units, T1/T2 and T3/T4 (all 75/125 MVA units), having a summer 10-Day LTR of 366 MW. The station's 2021 actual non-coincident summer peak load was about 253 MW and is forecasted to be approximately 367 MW (net adjusted for extreme weather) in 2031.

Bathurst TS also comprises two DESN units, T1/T2 and T3/T4 (all 75/125 MVA units), having a summer 10-Day LTR of 361 MW. The station's 2021 actual non-coincident summer peak load was about 241 MW and is forecasted to be approximately 350 MW (net adjusted for extreme weather) or 97% of its LTR in 2031. The TWG recommends this need be reviewed in the next phases of this RP cycle.

7.3.7 Warden TS – Station Capacity

Warden TS comprises one DESN unit, T3/T4 (75/125 MVA), having a summer 10-Day LTR of 182 MW. The station's 2021 actual non-coincident summer peak load was about 150 MW and is forecasted to be approximately 195 MW and 185 MW (net adjusted for extreme weather) in 2024 and 2031.

The demand at Warden TS exceeds its station LTR in 2024 due to new large customer connection request in the south Toronto. THESL will manage it in the near/medium term by transferring load to its closest station Scarboro TS as discussed in Section 7.1.5. The TWG recommends this need be reviewed in the next phases of this RP cycle.

7.3.8 Manby W TS Autotransformers – Transformation Capacity

The long-term transformation capacity need at Manby West TS was identified in the previous RIP. Manby West TS 230/115 kV autotransformers were found to be restricted by the lowest rated unit T12 in the fleet, and is potentially overloaded within the 2030-2035 time period, following T1 or T2 contingency. This NA also affirms this transformation capacity need and the autotransformer replacement plan for T12 that is expected to provide relief to this constraint as discussed in Section 7.1.9. The current planned in-service date of the T12 autotransformer replacement is around 2030. The TWG recommends that the long-term supply need in this area be reviewed as part of the next phase of this RP cycle.

7.3.9 Leaside TS Autotransformers – Transformation Capacity

The long-term transformation capacity need at Leaside TS was identified in the previous RIP. Leaside TS 230/115 kV autotransformers were found to be restricted by the lowest rated unit T16 in the fleet, and is potentially overloaded within the 2035-2040 time period, following T15 or T17 contingency, assuming that two of the three units at Portlands Energy Centre GS are out-of-service, and total plant generation is 160 MW. Post-contingency control action is currently available to resolve this issue by transferring Dufferin TS to Manby supply. The TWG recommends this need be monitored and reviewed in the next phases of this RP cycle.

7.3.10 Parkway TS to Richview TS 230 kV Corridor – Line Capacity

The 230 kV circuits P21R/P22R provide the transmission network connection between Parkway TS and Richview TS. These circuits also supply two transformer stations in the City of Markham as well as three transformer stations in the Northwest Toronto area (Leslie TS, Bathurst TS, and Finch TS) together with the other 230 kV circuits on the "Finch Corridor" between Cherrywood TS and Richview TS.

With the increasing demand forecasted on this corridor, some sections of the circuits P21R/P22R[3] are over 90% of their ratings under certain contingencies in the medium term and are potentially overloaded in the long term. Consideration may be given to reconductoring part of the circuits close to the Parkway TS end. It is to be noted that the baseline NA forecast does not reflect a number of customers that show interest in connecting new load near the Steeles / Hwy 404 area. The need for this corridor upgrade may become sooner. The TWG recommends this need be monitored and reviewed in the next phase of this RP cycle.

[3] The line section between Markham #1 Jct. and CTS Jct. of the circuits P21R/P22R is found to be the most restrictive in this NA review; however, the scope and timing of the preferred plan for this need will be reviewed and determined in the next phases of this RP cycle when a more certain and longer term load forecast will become available and considered.

7.3.11 Leaside TS to Wiltshire TS 115 kV Corridor – Line Capacity

The 115 kV transmission corridor between Leaside TS and Wiltshire TS comprises four circuits L13W, L14W, L18W and L15. It provides supply to Midtown Toronto area via two transformer stations Bridgman TS and Dufferin TS. The 2021 actual total coincident summer peak load of these stations was about 257 MW and is forecasted to be approximately 280 MW (net adjusted for extreme weather) in 2031. This corridor also provides backup supply to other stations that are normally connected to the Manby East subsystem such as Wiltshire TS, Fairbank TS and/or Runnymede TS.

The line capacity need on this corridor was identified as a long-term need (2035-2040) in the previous RIP, that the 1.8 km underground section of the circuit L15 between Bayview Jct. and Balfour Jct. is potentially overloaded in the long term. In this NA review, the contingency flow on this line section is about 80% of its limited time emergency rating in 2031. The TWG recommends the loading and the line capacity need on this Leaside TS x Wiltshire TS corridor be monitored and reviewed in the next phase of this RP cycle.

7.4 Load Restoration Analysis

The contingencies from the previous load restoration analysis in the 2nd cycle IRRP are reviewed along with this new NA forecast. The potential load interrupted by configuration for the following contingencies is significantly higher than the amount from the 2nd cycle IRRP.

For the loss of 230kV circuits C14L and C17L[4] (stations connected are Warden TS and Bermondsey TS), a total load of 379 MW in 2031 will be interrupted by configuration and 129 MW of it will need to be restored within 30 minutes based on the load restoration criteria in the ORTAC.

For the loss of 230kV circuits C18R and P22R[5] (Bathurst TS), a total load of 350 MW in 2031 will be interrupted by configuration and 100 MW of it will need to be restored within 30 minutes based on the load restoration criteria in the ORTAC.

THESL has indicated that the current distribution feeder configuration and spare capacity from the nearby stations will not be adequate to resupply all of the aforementioned amount of load in excess of 250 MW within 30 minutes and recommends that these load restoration scenarios and options be reviewed in the next phase of this RP cycle.

8 SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended

[4] The circuits C14L and C17L only share the same towers along a 4 km overhead line tap supplying Warden TS.
[5] The circuits C18R and P22R only share the same towers along a 2 km overhead line tap supplying Bathurst TS.

investments. The TWG has determined that the key electric demand driver in the Toronto Region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and electrified heating.[6]

A high demand growth forecast was developed by applying + 5% on the extreme summer corrected Normal Growth net load forecast. The TWG has also considered a slower EV and electrified heating change and developed a low demand growth forecast by applying - 2.5% on the extreme summer corrected Normal Growth net load forecast.

The impact of sensitivity analysis for the high and low growth scenarios on the capacity needs identified in Section 7 is summarized in Table 6.

Table 6: Impact of Sensitivity Analysis on the Identified Capacity Needs

Need	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario (1)
Manby TS to Riverside Jct 115 kV Corridor	2026	2026	2026
Fairbank TS	Beyond 2031	Beyond 2031	-
Sheppard TS	Beyond 2031	Beyond 2031	-
Strachan TS	Beyond 2031	Beyond 2031	-
Basin TS	Beyond 2031	2031	-
Glengrove TS	Beyond 2031	2031	-
Finch TS / Bathurst TS	Beyond 2031	2028	-
Warden TS	Beyond 2031	TBD (2)	-
Manby W TS Autotransformers (T12)	Beyond 2031	Beyond 2031	-
Leaside TS Autotransformers (T16)	Beyond 2031	2031	-
230 kV Parkway TS to Richview TS Corridor	Beyond 2031	Beyond 2031 (3)	-
115 kV Leaside TS to Wiltshire TS Corridor	Beyond 2031	Beyond 2031	-

(1) The objective of a low growth scenario analysis is to identify any deferment in the timing of needs identified in this NA. Therefore, the long-term needs will not be looked at in the low growth scenario analysis.
(2) Forecasted load demand at Warden TS exceeds its capacity from 2024 but THESL plans to manage it by transferring the excess load to Scarboro TS. A higher load growth scenario will certainly advance the need to relieve Warden TS and further assessment will be carried out during the next phases of this Regional Planning cycle.
(3) Like the normal growth scenario, the high growth scenario does not reflect several customers that show interest in connecting new load near the Steeles / Hwy 404 area. The need for this corridor upgrade may be advanced to the medium term. The TWG recommends this need be monitored and reviewed in the next phases of this RP cycle.

In the high growth scenario, the timing of some of the long-term station capacity needs (Basin TS, Glengrove TS, Finch TS / Bathurst TS, and potentially Warden TS as well) is advanced to the medium-term timeframe. The timing of the long-term transformation capacity needs at Leaside TS is also advanced to 2031. The TWG recommends these needs be assessed during the next phases of this RP cycle.

The timing of the near-term capacity need on the 115 kV corridor between Manby TS and Riverside Jct. does not change in the sensitivity analysis. As discussed in Section 7.2.2, the TWG recommends Hydro One proceed on the development work for reconductoring the circuits K13J/K14J to higher ampacity conductors without replacing the existing towers and this need be reviewed as part of the next phase of this RP cycle.

[6] The sensitivity analysis does not consider the impact from the IESO's "Pathways to Decarbonization" report published on December 15, 2022. The electricity demand and new infrastructure need in the longer term could be substantially higher than anticipated in this report, and will be assessed in the next phase of this RP cycle.

9 RECOMMENDATIONS

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

a) No further regional coordination is required for the following need:
- Asset renewal needs for replacing the major HV equipment as listed in Table 7 below. These needs will be addressed directly by Hydro One and THESL to develop a preferred replacement plan giving consideration to "right-sizing";

b) Further assessment and regional coordination is required in the next phases of the RP cycle to review and/or develop a preferred plan for the follow needs:
- The line capacity need for the 115 kV corridor between Manby TS and Riverside Jct. Hydro One will initiate the development work for reconductoring the overhead line section; and
- The load restoration and long-term needs as listed in the following table.

Table 7 summarizes the above recommendations.

Table 7: Summary of Recommendations

Further Regional Coordination Not Required	Further Regional Coordination Required
Asset Renewal Needs (Stations): • Strachan T14 & T13/T15 • Charles TS: T3/T4 • Duplex TS: T1/T2 & T3/T4 • Basin TS: T3/T5 • Scarboro TS: T23 • Fairchild TS: T1 & T3/T4 • Bermondsey TS: T3/T4 • Malvern TS: T3 • Manby TS: T7, T9, T12 autotransformers, T13/T14 step-down transformer • Leslie TS: T1 **Asset Renewal Needs (Lines):** • 115 kV H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. overhead section • 115 kV L9C/L12C: Leaside TS to Balfour Jct. overhead section **Line Capacity Need:** • 230 kV Richview TS to Manby TS Corridor **Station Capacity Need:** • Fairbank TS • Strachan TS	**Line Capacity Need:** • 115 kV Manby TS to Riverside Jct. Corridor **Load Restoration:** • Loss of C14L/C17L • Loss of C18R/P22R **Long-Term Needs:** • Sheppard TS – Station Capacity • Basin TS – Station Capacity • Glengrove TS – Station Capacity • Finch TS / Bathurst TS – Station Capacity • Warden TS – Station Capacity • 230/115kV Manby W Autotransformers – Transformation Capacity • 230/115kV Leaside TS Autotransformers – Transformation Capacity • 230 kV Parkway TS to Richview TS Corridor – Line Capacity • 115kV Leaside TS to Wiltshire TS Corridor – Line Capacity

This NA assessment was performed before the publication of the IESO's "Pathways to Decarbonization" report on December 15, 2022, and does not include its impact on the need and/or the timing for additional electrical supply facilities in the Toronto Region. The TWG recommends that the "Pathways to Decarbonization" and its subsequent impact be considered and assessed in the next phase of this RP cycle.

10 REFERENCES

[1]. Hydro One, "Toronto Regional Infrastructure Plan", March 6, 2020.
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[5]. IESO, Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0, August 22, 2007
https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/connecting/IMO-REQ-0041-TransmissionAssessmentCriteria.ashx

Appendix A-1: Non-Coincident Summer Peak Net Load Forecast (2022 to 2031)

STATIONS	DESN ID	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NORTH 230kV		**1902**	**1249**	**1317**	**1388**	**1459**	**1483**	**1513**	**1525**	**1553**	**1573**	**1575**	**1577**
Agincourt TS	T5/T6	174	88	89	91	98	102	105	106	106	108	108	108
Bathurst TS	T1/T2	183	131	120	123	125	142	160	178	176	175	174	172
	T3/T4	178	110	135	131	146	148	146	146	163	181	179	178
Cavanagh MTS	T1/T2	157	120	117	118	121	121	127	130	141	141	141	142
Fairchild TS	T1/T2	174	108	119	131	134	134	134	134	133	132	132	132
	T3/T4	172	108	118	117	116	114	114	113	112	112	112	112
Finch TS	T1/T2	180	129	144	167	176	178	181	182	182	183	184	185
	T3/T4	186	124	132	156	179	178	178	178	177	179	181	182
Leslie TS	T1/T2 13.8	43	9	13	14	13	10	11	0	0	0	0	0
	T1/T2 27.6	96	85	86	92	100	102	88	91	91	92	93	93
	T3/T4 27.6	184	127	139	141	141	143	157	157	158	157	157	156
Malvern TS	T3/T4	176	110	106	108	108	109	112	112	113	114	115	119
EAST 230kV		**1475**	**962**	**1018**	**1059**	**1154**	**1156**	**1158**	**1186**	**1207**	**1209**	**1212**	**1213**
Bermondsey TS	T1/T2	186	60	75	103	109	109	127	143	142	142	141	140
	T3/T4	162	93	120	124	129	132	113	131	130	129	132	135
Ellesmere TS	T3/T4	189	124	123	131	152	157	157	156	165	165	164	163
Leaside TS	T19/T20/T21 13.8	100	67	70	70	69	70	71	71	71	71	71	71
	T19/T20/T21 27.6	110	83	81	80	78	78	77	76	75	75	74	74
Scarboro TS	T21/T22	189	109	113	111	137	139	138	136	150	150	151	150
	T23/T24	151	108	112	111	112	109	108	108	108	108	108	107
Sheppard TS	T1/T2	95	76	69	70	70	70	70	70	70	81	81	82
	T5/T6 (was T3/T4)	109	91	98	100	103	105	106	108	109	103	104	105
Warden TS	T3/T4	182	150	156	160	195	187	191	188	186	186	186	185
WEST 230kV		**1239**	**768**	**752**	**796**	**837**	**810**	**828**	**864**	**862**	**870**	**879**	**889**
Horner TS	T1/T2	184	0	30	31	39	40	96	95	95	95	95	95
	T3/T4	182	147	126	147	145	145	117	115	115	114	114	113
Manby TS	T13/T14	106	85	81	82	98	98	83	83	84	84	86	86
	T3/T4	60	73	58	58	59	60	53	53	53	55	56	58
	T5/T6	60	79	64	66	65	53	55	56	57	59	59	61
Rexdale TS	T1/T2	187	102	104	108	108	93	93	140	144	148	154	160
Richview TS	T1/T2	159	111	114	112	111	109	108	106	105	104	103	102
	T5/T6	188	103	104	121	142	141	150	140	132	132	132	133
	T7/T8	113	68	70	71	71	72	74	76	77	79	80	81
LEASIDE 115kV		**1779**	**1141**	**1265**	**1318**	**1339**	**1365**	**1365**	**1369**	**1382**	**1389**	**1403**	**1416**
Basin TS	T3/T5	88	57	74	59	67	69	72	77	81	82	82	85
Bridgman TS	T11/T12/T13/T14/T15	189	133	145	146	148	147	147	147	147	147	148	150
Carlaw TS	T1/T2	73	63	43	43	42	47	49	50	51	52	53	53
Cecil TS	T1/T2	85	55	61	60	59	58	57	55	54	55	57	57
	T3/T4	130	92	91	89	89	87	86	84	82	81	81	82
Charles TS	T1/T2	130	70	86	91	95	93	98	97	98	97	96	95
	T3/T4	81	57	62	64	60	71	71	72	71	70	70	70
Dufferin TS	T1/T3	94	46	53	64	59	63	65	66	66	67	67	67
	T2/T4	86	80	71	70	68	69	68	66	66	65	65	65
Duplex TS	T1/T2	81	55	66	68	70	70	72	73	73	75	76	78
	T3/T4	47	35	36	33	32	32	33	33	33	33	33	34
Esplanade TS	T11/T12/T13	187	125	145	150	155	157	156	155	157	158	158	158
Gerrard TS	T1/T2	128	30	55	78	80	79	80	80	84	88	91	91
Glengrove TS	T1/T3	44	17	31	33	35	35	35	35	36	36	37	37
	T2/T4	44	30	32	36	39	39	41	42	44	46	47	49
Main TS	T3/T4	77	56	60	62	62	63	63	64	64	65	66	67
Terauley TS	T1/T4	108	53	61	91	95	99	85	85	87	87	88	89
	T2/T3	108	88	92	81	86	86	88	88	88	88	88	89
MANBY E 115kV		**579**	**362**	**374**	**399**	**421**	**428**	**430**	**428**	**429**	**430**	**432**	**436**
Fairbank TS	T2/T4	90	90	96	86	89	90	91	88	89	89	90	91
	T1/T3 (to be T5/T6)	92	107	89	81	74	74	75	75	76	77	78	79
Runnymede TS	T1/T2	108	78	80	95	108	110	106	105	104	103	103	102
	T5/T6 (was T3/T4)	111	32	28	44	49	53	57	59	60	61	62	65
Wiltshire TS	T1/T6	48	25	34	34	34	34	35	35	35	35	36	36
	T7X/T2X	129	30	47	59	67	67	66	65	65	64	64	64
MANBY W 115kV		**611**	**374**	**375**	**380**	**423**	**425**	**518**	**516**	**511**	**508**	**506**	**505**
Copeland MTS	T1/T3	130	80	104	114	120	121	182	179	177	175	174	173
John TS	T1/T2/T3/T4	187	83	39	37	61	59	98	99	143	142	141	140
	T5/T6	123	75	92	92	99	99	101	101	54	53	53	52
Strachan TS	T12/T14	74	52	59	56	57	57	87	86	86	86	86	87
	T13/T15	97	84	81	81	86	89	50	50	51	52	52	53
TOTAL REGIONAL LOAD		**7586**	**4856**	**5100**	**5341**	**5633**	**5667**	**5812**	**5887**	**5944**	**5979**	**6008**	**6036**

Appendix A-2: Coincident Summer Peak Net Load Forecast (2022 to 2031)

STATIONS	DESN ID	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NORTH 230kV		**1902**	**1173**	**1240**	**1309**	**1376**	**1401**	**1430**	**1444**	**1470**	**1490**	**1492**	**1493**
Agincourt TS	T5/T6	174	72	73	74	80	83	86	86	87	88	89	88
Bathurst TS	T1/T2	183	127	116	119	121	138	156	173	171	170	169	168
	T3/T4	178	110	135	131	146	148	146	145	163	180	179	178
Cavanagh MTS	T1/T2	157	96	93	94	97	97	101	104	113	113	113	113
Fairchild TS	T1/T2	174	106	117	129	132	132	132	131	131	130	130	129
	T3/T4	172	108	118	117	116	114	114	113	112	112	112	112
Finch TS	T1/T2	180	128	143	166	175	177	180	180	181	181	182	183
	T3/T4	186	124	133	156	179	178	178	178	177	179	181	182
Leslie TS	T1/T2 13.8	43	5	7	8	7	6	6	0	0	0	0	0
	T1/T2 27.6	96	74	75	80	87	89	76	79	80	80	81	81
	T3/T4 27.6	184	127	139	141	141	143	157	157	158	157	157	156
Malvern TS	T3/T4	176	96	92	94	94	95	97	98	98	99	100	104
EAST 230kV		**1475**	**865**	**915**	**950**	**1029**	**1033**	**1031**	**1056**	**1075**	**1076**	**1079**	**1080**
Bermondsey TS	T1/T2	186	48	60	82	87	87	101	114	113	113	113	112
	T3/T4	162	88	114	117	122	125	107	124	123	122	125	128
Ellesmere TS	T3/T4	189	116	115	122	141	147	146	145	154	154	153	152
Leaside TS	T19/T20/T21 13.8	100	66	69	69	68	69	70	70	70	70	70	70
	T19/T20/T21 27.6	110	79	77	76	74	74	73	72	72	71	71	70
Scarboro TS	T21/T22	189	94	97	96	118	119	118	117	129	129	129	129
	T23/T24	151	107	111	110	111	109	108	107	108	107	107	107
Sheppard TS	T1/T2	95	65	60	60	60	60	60	60	60	69	70	70
	T5/T6 (was T3/T4)	109	89	96	97	100	102	104	105	106	101	102	103
Warden TS	T3/T4	182	113	118	120	147	141	144	141	140	140	140	140
WEST 230kV		**1239**	**648**	**640**	**680**	**711**	**685**	**710**	**745**	**743**	**749**	**756**	**764**
Horner TS	T1/T2	184	0	30	31	39	40	96	95	95	95	95	95
	T3/T4	182	144	123	144	142	142	115	112	112	112	111	111
Manby TS	T13/T14	106	58	55	56	67	67	57	57	57	57	59	58
	T3/T4	60	36	29	29	29	30	26	26	26	27	28	29
	T5/T6	60	75	60	62	62	50	52	53	54	56	55	57
Rexdale TS	T1/T2	187	97	99	103	102	89	88	133	137	141	147	152
Richview TS	T1/T2	159	109	112	110	108	107	106	104	103	102	101	100
	T5/T6	188	83	84	98	114	114	121	113	106	106	107	107
	T7/T8	113	46	47	48	48	49	50	51	53	54	54	55
LEASIDE 115kV		**1779**	**1131**	**1253**	**1305**	**1326**	**1352**	**1351**	**1355**	**1368**	**1375**	**1389**	**1401**
Basin TS	T3/T5	88	57	74	59	67	69	72	77	81	82	82	85
Bridgman TS	T11/T12/T13/T14/T15	189	133	145	146	148	148	147	147	147	147	149	151
Carlaw TS	T1/T2	73	62	43	42	41	46	49	49	50	51	52	52
Cecil TS	T1/T2	85	55	61	61	59	58	57	56	54	55	57	57
	T3/T4	130	92	91	89	89	87	86	84	82	80	81	82
Charles TS	T1/T2	130	70	86	91	94	93	97	97	97	96	95	94
	T3/T4	81	57	61	64	60	70	71	71	70	70	70	70
Dufferin TS	T1/T3	94	46	53	63	58	63	64	65	66	66	66	66
	T2/T4	86	78	69	68	66	67	66	65	64	64	63	63
Duplex TS	T1/T2	81	55	67	68	70	71	72	73	74	75	76	78
	T3/T4	47	34	35	33	31	31	32	32	32	32	33	33
Esplanade TS	T11/T12/T13	187	125	145	150	155	156	156	155	157	157	157	158
Gerrard TS	T1/T2	128	29	53	76	77	77	77	77	81	85	88	88
Glengrove TS	T1/T3	44	16	30	32	34	34	34	34	34	35	35	36
	T2/T4	44	29	31	35	37	38	40	41	43	44	45	47
Main TS	T3/T4	77	54	58	60	61	61	62	62	62	63	64	65
Terauley TS	T1/T4	108	52	60	89	94	97	83	84	85	86	87	88
	T2/T3	108	87	91	80	85	85	87	87	87	87	88	88
MANBY E 115kV		**579**	**293**	**336**	**362**	**384**	**390**	**392**	**390**	**391**	**392**	**394**	**398**
Fairbank TS	T2/T4	90	79	84	75	78	79	80	77	78	78	79	80
	T1/T3 (to be T5/T6)	92	91	75	69	62	63	63	64	64	65	66	67
Runnymede TS	T1/T2	108	69	71	83	95	97	94	93	92	91	90	90
	T5/T6 (was T3/T4)	111	1	28	44	49	53	57	59	60	61	62	65
Wiltshire TS	T1/T6	48	23	32	32	32	32	33	33	33	33	34	34
	T7X/T2X	129	30	46	59	66	66	65	65	64	64	64	63
MANBY W 115kV		**611**	**370**	**371**	**376**	**418**	**420**	**512**	**510**	**506**	**503**	**501**	**500**
Copeland MTS	T1/T3	130	79	102	112	119	119	180	177	175	173	171	170
John TS	T1/T2/T3/T4	187	83	39	37	61	59	98	99	143	142	140	140
	T5/T6	123	74	91	91	98	98	100	99	53	53	52	52
Strachan TS	T12/T14	74	51	58	56	56	56	85	85	85	85	85	85
	T13/T15	97	83	80	80	85	88	49	50	50	51	52	53
TOTAL REGIONAL LOAD		**7586**	**4480**	**4756**	**4982**	**5245**	**5281**	**5426**	**5500**	**5553**	**5585**	**5611**	**5636**

Appendix B: Lists of Step-Down Transformer Stations (Current)

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	L14W/L15/L18W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cavanagh MTS T1/T2	230/27.6	C20R/C10A
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
Copeland MTS T1/T3	115/13.8	D11J/D12J
Dufferin TS T1/T3	115/13.8	L13W/L18W
Dufferin TS T2/T4	115/13.8	L13W/L18W
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/H10DE(C5E)/H9DE(C7E)
Fairbank TS T1/T3 (to be T5/T6)	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W

Station (DESN)	Voltage (kV)	Supply Circuits
Fairchild TS T1/T2	230/27.6	C18R/C20R
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/T2	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
Horner TS T1/T2	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	Leaside Buses HL2, HL3, HL16
Leaside TS T19/T20/T21 27.6	230/27.6	Leaside Buses HL2, HL3, HL16
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 27.6	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

Station (DESN)	Voltage (kV)	Supply Circuits
Richview TS T5/T6	230/27.6	V74R/V72R
Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
Runnymede TS T1/T2	115/27.6	K12W/K11W
Runnymede TS T5/T6 (was T3/T4)	115/27.6	K12W/K11W
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 T5/T6 (was 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 T7X/T2X	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)

Appendix C: Lists of Transmission Circuits

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	D11J, D12J, H9DE, H10DE	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 Bridgman x Wiltshire	L13W, L14W, L15, L18W	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 D: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
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
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
MEP	Municipal Energy Plan
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
RP	Regional Planning
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

Toronto

REGIONAL INFRASTRUCTURE PLAN

March 6, 2020

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Prepared and supported by:

Company
Alectra Utilities Corporation
Elexicon Energy Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Toronto Hydro-Electric System Limited
Hydro One Networks Inc. (Lead Transmitter)

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 any additional needs identified based on new and/or updated information provided by the RIP Study Team.

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 Study Team.

Study Team 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 WITH SUPPORT FROM THE RIP STUDY TEAM 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 TORONTO REGION.

The participants of the Regional Infrastructure Plan ("RIP") Study Team included members from the following organizations:

- Alectra Utilities ("Alectra")
- Elexicon Energy Inc. ("Elexicon")
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- Toronto Hydro-Electric System Limited ("THESL")
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the second cycle of Toronto regional planning process, which follows the completion of the Toronto Integrated Regional Resource Plan ("IRRP") in August 2019 and the Toronto Region Needs Assessment ("NA") in October 2017. This RIP provides a consolidated summary of the needs and recommended plans for Toronto Region over the planning horizon (1 – 20 years) based on available information.

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment and IRRP reports for this cycle, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, the following projects have been completed:

- Midtown Transmission Reinforcement Project (completed in 2016)
- Clare R. Copeland 115 kV Switching Station and Copeland MTS (completed in 2019)
- Manby SPS Load Rejection (L/R) Scheme (completion in 2019)

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in the Table 1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 1. Recommended Plans in Toronto Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate(1)
1	Main TS: End-of-life of transformers T3/T4	Replace the end-of-life transformers with similar type and size equipment as per current standard	2021	$33M
2	H1L/H3L/H6LC/H8LC: End-of-life of Leaside Jct. to Bloor St. Jct. overhead section	Refurbish the end-of-life H1L/H3L/H6LC/H8LC section	2023	$11M
3	L9C/L12C: End-of-life of Leaside TS to Balfour Jct. overhead section	Refurbish the end-of-life L9C/L12C section	2023	$3M
4	C5E/C7E: End-of-life of underground cables between Esplanade TS and Terauley TS	Replace the end-of-life C5E/C7E cables	2024	$128M
5	Richview TS to Manby TS 230 kV Corridor Reinforcement	Replace existing idle 115 kV double circuit line with new 230 kV double circuit line between Richview TS and Manby TS	2023	$21M
6	Manby TS: End-of-life of autotransformers (T7, T9, T12), step-down transformer (T13), and the 230 kV switchyard	Replace the end-of-life transformers with similar type and size equipment as per current standard, and refurbish/reconfigure Manby 230 kV switchyard	2025	$85M
7	Bermondsey TS: End-of-life of transformers T3/T4	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	$27M
8	John TS: End-of-life of transformers (T1, T2, T3, T4, T5, T6), 115 kV breakers, and LV switchgear	Replace with similar type and size equipment as per current standard	2026	$102M

(1) Budgetary estimates are provided for Hydro One's portion of the work

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 1 while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

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1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE TORONTO REGION BETWEEN 2019 AND 2039.

The report was prepared by Hydro One Networks Inc. (Transmission) (“Hydro One”) on behalf of the Study Team that consists of Hydro One, Alectra Utilities (“Alectra”), Elexicon Energy Inc. (“Elexicon”), Hydro One Networks Inc. (Distribution), the Independent Electricity System Operator (“IESO”), and Toronto Hydro-Electric System Limited (“THESL”) in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The Toronto Region is comprised of the area within the municipal boundary of the City of Toronto. Electrical supply to the region is provided by thirty-five 230 kV and 115 kV step-down transformer stations (“TS”) as shown in Figure 1-1. The outer parts of the region to the east, north, and west are supplied by fifteen 230/27.6 kV and two 230/27.6-13.8 kV step-down transformer stations. The central area is supplied by two 230/115 kV autotransformer stations at Leaside TS and Manby TS, and sixteen 115/13.8 kV and two 115/27.6 kV step-down transformer stations.

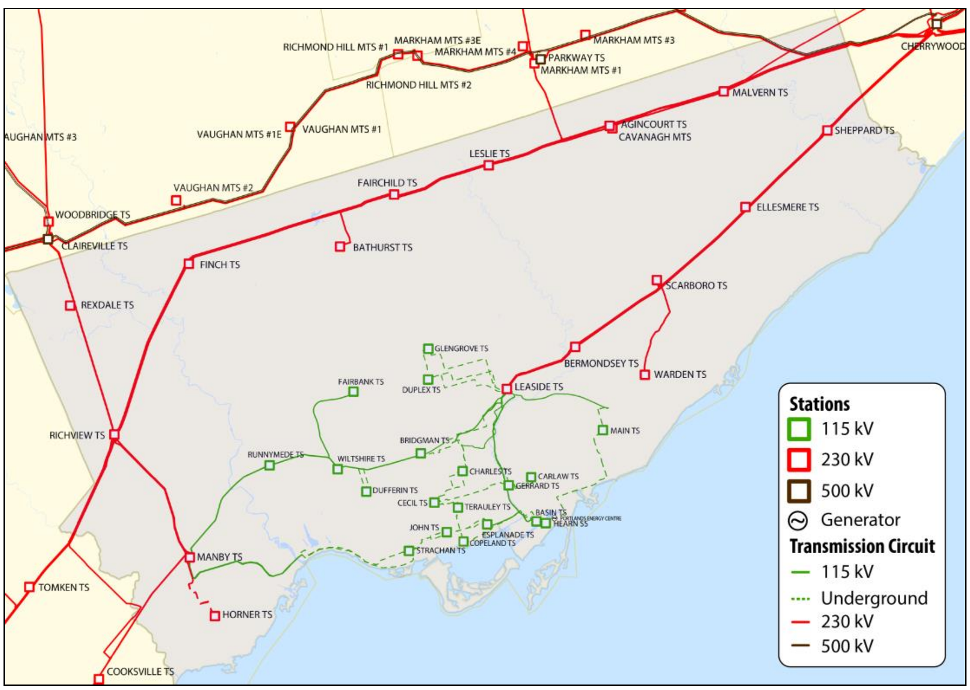

Figure 1-1: Toronto Region Map

1.1 Objectives and Scope

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

- Provide a comprehensive summary of needs and wires plans to address the needs;

- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), and/or Integrated Regional Resource Plan ("IRRP");
- Assess and develop a wires plan to address these needs; and
- 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 reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the near, mid- and long-term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, 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 relevant wires plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, and/or Integrated Regional Resource Plan);
- Discussion of any other major transmission infrastructure investment plans over the planning horizon;
- Identification of any new needs 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 Study Team.

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 adequacy of the transmission facilities in the region over the study period.
- 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 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 Study Team 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.

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 that 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, Indigenous communities, business sectors and other interested stakeholders in the region.

[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; 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 is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or 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;
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers.

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.

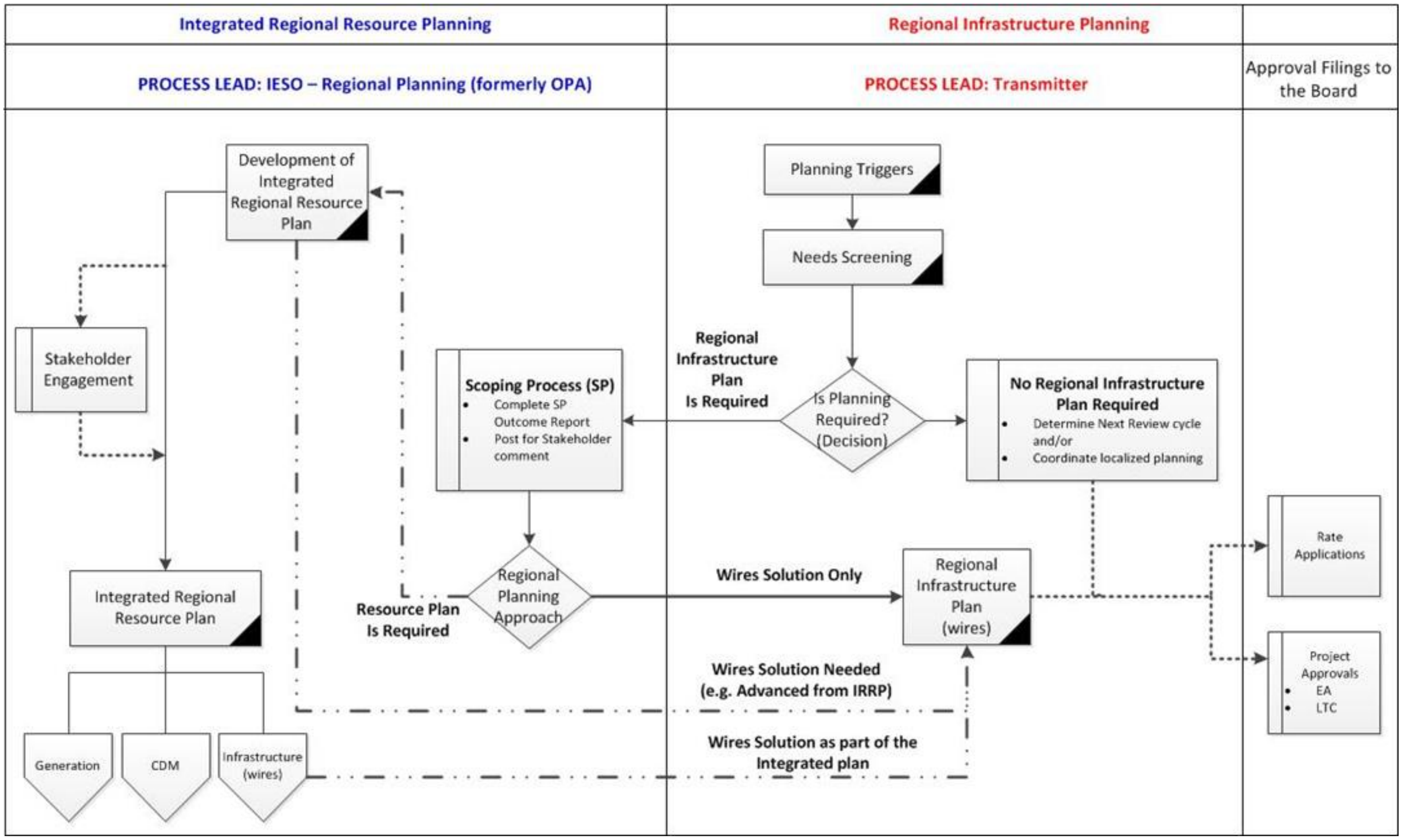

Figure 2-1: Regional Planning Process Flowchart

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 phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team 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. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required

or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.

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.

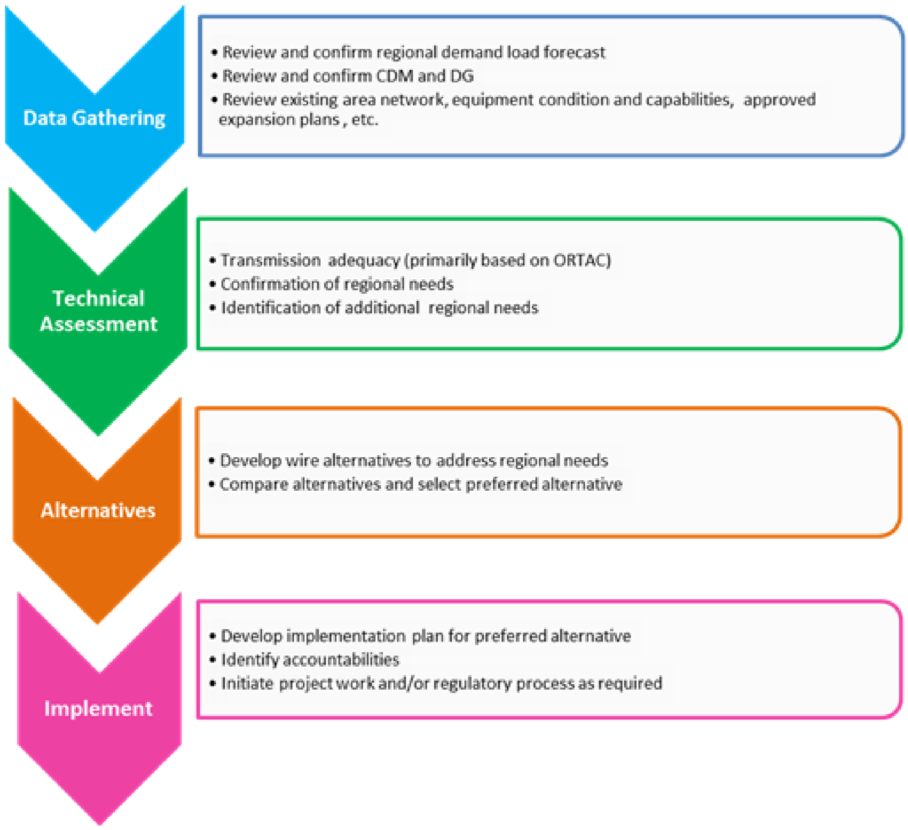

Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE 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 Toronto Region is provided through three 500/230 kV transformers stations at 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 the Downtown area and connected to the 115 kV network at Hearn Switching Station (“SS”). The Toronto Region summer coincident peak demand in 2018 was about 4,660 MW which represents about 20% of the gross total demand (23240 MW) in the province.

Toronto Hydro-Electric System Limited (“THESL”) is the main Local Distribution Company (“LDC”) which serves the electricity demand in the Toronto Region. Other LDCs supplied from electrical facilities in the Toronto Region are Hydro One Networks Inc. Distribution, Alectra Utilities and Elexicon Energy Inc. The LDCs receive power at the step-down transformer stations and distribute it to the end-users – industrial, commercial and residential customers.

A single line diagram showing the electrical facilities of the Toronto Region is provided in Figure 3-1. Copeland MTS is a new THESL owned transformer station which serves the Downtown area and came into service in Q1 2019.

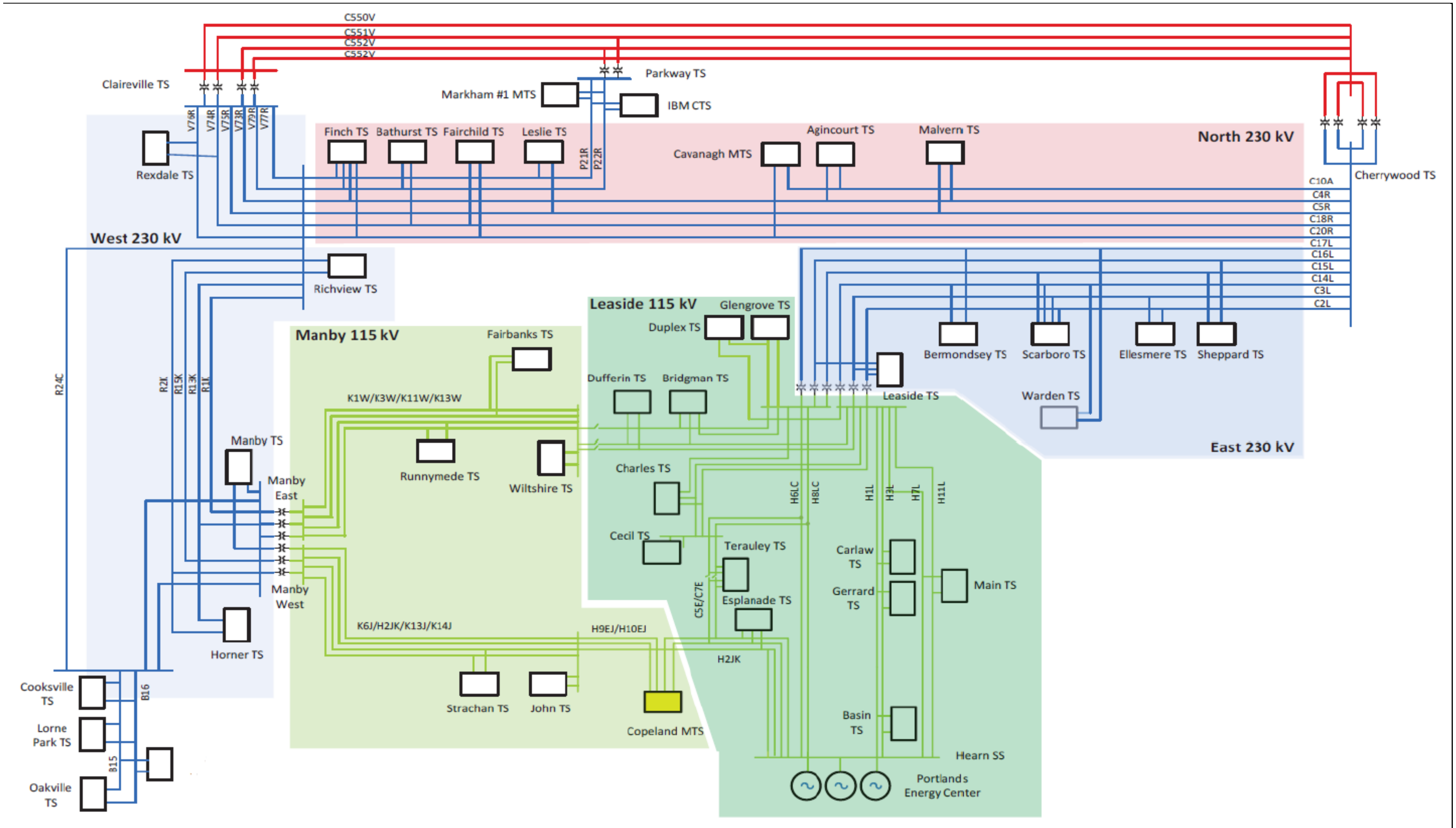

Figure 3-1: Single Line Diagram of Toronto Region's Transmission Network

The thirty-five Toronto's transformer stations can be grouped into five electrical zones based on their HV supply network:

1. **Leaside 115 kV Area:** The transformer stations in this area are supplied by the Leaside TS 230/115 kV autotransformers, and serve roughly the customers in the eastern part of Central Toronto. A list of the transformer stations in this area is provided below.
    - Basin TS
    - Bridgman TS
    - Carlaw TS
    - Cecil TS
    - Charles TS
    - Dufferin TS
    - Duplex TS
    - Esplanade TS
    - Gerrard TS
    - Glengrove TS
    - Main TS
    - Terauley TS

2. **Manby 115 kV Area:** This area covers the western part of Central Toronto which is supplied by the Manby TS 230/115 kV autotransformers. The transformer stations in this area is listed below.
    - Copeland MTS
    - Fairbank TS
    - John TS
    - Runnymede TS
    - Strachan TS
    - Wiltshire TS

3. **East 230 kV Area:** This area includes transformer stations connected to the 230 kV circuits between Cherrywood TS and Leaside TS C2L/C3L, C14L/C15L, and C16L/C17L, serving customers in the outer-eastern part of Toronto and Scarborough areas. Below are the transformer stations in East 230 kV area.
    - Bermondsey TS
    - Ellesmere TS
    - Leaside TS
    - Scarboro TS
    - Sheppard TS
    - Warden TS

4. **North 230 kV Area:** This area covers the outer northern part of Toronto bordering the York Region. The transformer stations in this area, listed below, are supplied by the 230kV circuits connecting Richview TS, Cherrywood TS, and/or Parkway TS C4R/C5R, C18R/C20R, P21R/P22R.
    - Agincourt TS
    - Bathurst TS
    - Cavanagh MTS
    - Fairchild TS
    - Finch TS
    - Leslie TS
    - Malvern TS

5. **West 230 kV Area**: The transformer stations in this area serve customers in the outer western part of Toronto including Etobicoke, and includes stations supplied by the Claireville TS to Richview TS 230 kV circuits V73R/V74R/V75R/V76R/V77R/V79R and the Richview TS to Manby TS 230 kV circuits R1K/R2K and R13K/R15K. Below are the transformer stations in West 230 kV area.
    - Horner TS
    - Manby TS
    - Rexdale TS
    - Richview TS

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

OVER THE LAST TEN YEARS, A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY TO THE TORONTO REGION.

A summary and description of the major projects completed and/or currently underway over the last ten years is provided below.

- Incorporation of the 550 MW Portland's Energy Centre (2009) – Covered modification to the Hearn 115 kV switchyard to connect the new generation.

- 115 kV Switchyard Work at Hearn SS, Leaside TS, and Manby TS (2013, 2014) – Includes replacement of the aging 115 kV switchyard at Hearn SS with a new gas-insulated switchgear ("GIS") and replacement of all 115 kV oil 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 and 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 (completed in 2016) – Covered replacement of the aging L14W underground cable and addition of a new 115 kV circuit between Leaside TS and Bridgman TS.

- Clare R. Copeland 115 kV Switching Station (completed in 2019) – Built to connect a new THESL owned 115/13.8 kV step-down transformer station (Copeland MTS) in Downtown Toronto.

- Runnymede TS DESN#2 and Manby TS to Wiltshire TS Circuits Upgrade Project (2018) – covered building of a second 50/83MVA, 115/27.6kV DESN at Runnymede TS and reinforcement of the Manby TS to Wiltshire TS 115kV circuits to accommodate increasing load demand in the area.

- Manby SPS Load Rejection (L/R) Scheme (2019) – Built to ensure that loading on in-service equipment at Manby TS is not exceeded for loss of two out of three autotransformers in the Manby East TS and Manby West switchyards.

- Horner TS DESN #2 Project (2022) – covers construction of a second 75/125MVA, 230/28 kV, DESN at the Horner TS site to meet the load growth in the south west Toronto area.

- Richview to Manby Corridor Reinforcement (R X K) Project (2023)– Adding a third double-circuit line between Richview TS and Manby TS, aimed to increase the transmission line capacity between the two stations to meet forecast load demand in the South West GTA.

- Multiple Station Refurbishment Projects – Work is also under way on refurbishing Bridgman TS, Fairbank TS, Main TS and Runnymede TS DESN#1. These projects are expected to be completed between 2021 and 2024.

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The electricity demand in the Toronto Region is anticipated to grow at an average rate of 0.9% over the next ten years. Figure 5-1 shows the Toronto Region's summer peak load forecast developed during the Toronto IRRP process. This IRRP forecast was used to determine the loading that would be seen by transmission lines and autotransformer stations and to identify the need for additional line and auto-transformation capacity. Figure 4-1 also shows the Toronto region's non-coincident load forecast developed using the individual station's peak loads and which was used to determine the need for station capacity.

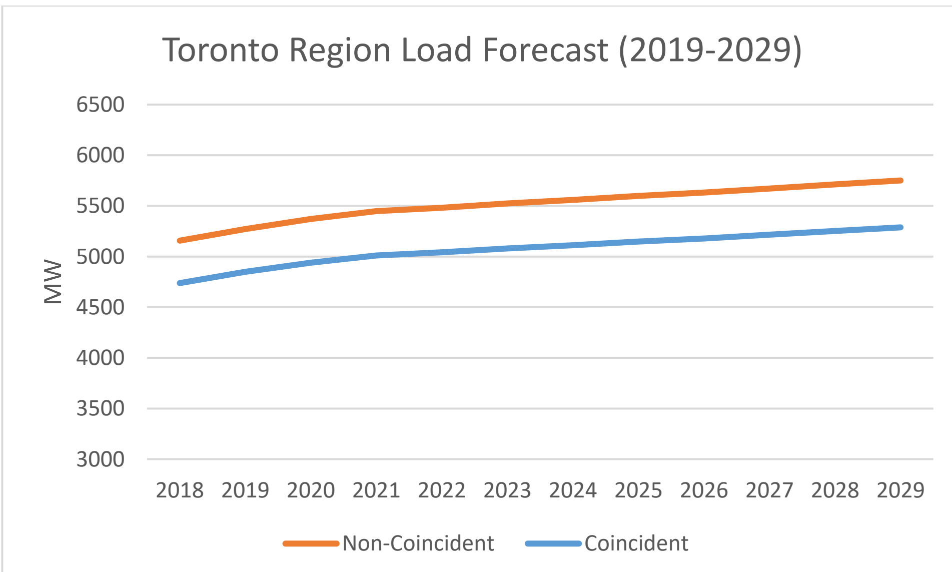

Figure 5-1: Toronto Region Load Forecast

The IRRP forecast shows that the Region peak summer load increases from 4850 MW in 2019 to 5290 MW by 2029. The corresponding non-coincident summer peak loads increase from 5270 MW to about 5750 MW over the same period. The IRRP and non-coincident load forecasts for the individual stations in the Toronto Region is given in Appendix D, Table D-1 and Table D-2.

The IRRP had provide an estimated of the energy-efficiency savings resulting from building codes and equipment standards improvement in Ontario. This has the potential to lower the demand growth in the region to approximately 0.6% annually. Details for the individual stations peak loads considering the energy-efficiency are given in Appendix D, Table D-3 and Table D-4.

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2029.
- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period 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 is determined by the summer 10-day Limited Time Rating (LTR).
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- Metrolinx plans to connect three Traction Power Substation (TPSS) to Hydro One's 230 kV circuits in Toronto area for GO Transit electrification – Mimico TPSS to K21C and K23C close to Manby TS; City View TPSS to V73R and V77R north of Richview TS; and Scarborough TPSS to C2L and C14L at Scarboro TS. Metrolinx have advised that their current electrification schedule is uncertain and new facilities would be built likely beyond 2023. Appendix F of the 2019 Toronto IRRP ("Richview TS x Manby TS Study") verified that the reinforcement of Richview TS to Manby TS Transmission Corridor is required by 2021 and that Metrolinx new load do not affect the need and timing of the project. After the completion of Richview TS to Manby TS Transmission Reinforcement, the new TPSS loads can be connected without need of any new facilities.

6 ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE TORONTO REGION OVER THE PLANNING PERIOD (2019-2039). ALL PROJECTS CURRENTLY UNDERWAY ARE ASSUMED IN-SERVICE.

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

- 2017 Toronto Region Needs Assessment ("NA") Report
- 2019 Toronto Integrated Regional Resource Plan ("IRRP") and Appendices

This section provides a review of the adequacy of the transmission lines and stations in the Metro Toronto Region. The adequacy is assessed using the latest regional load forecast provided in Appendix D from a loading perspective. Sustainment aspects were identified in the NA report and are addressed in Section 7 of this report. The review assumes that the following projects shown in Table 6-1 are in-service. Sections 6.1 to 6.4 present the results of this review.

Table 6-1: New Facilities Assumed In-Service

Facility	In-Service Date
Second DESN at Horner TS	2022
Richview to Manby 230 kV Corridor Reinforcement	2023
Copeland MTS Phase 2	2024

6.1 230 kV Transmission Facilities

The Metro Toronto 230 kV transmission facilities consist of the following 230 kV transmission circuits (please refer to Figure 3-1):

a) Cherrywood TS to Leaside TS 230 kV circuits: C2L, C3L C14L, C15L, C16L, and C17L
b) Cherrywood TS to Agincourt TS 230 kV circuit C10A
c) Cherrywood TS to Richview TS 230 kV circuits: C4R, C5R, C18R, and C20R
d) Parkway TS to Richview TS 230 kV circuits: P21R and P22R
e) Claireville TS to Richview TS 230 kV circuits: V73R, V74R, V75R, V76R, V77R, and V79R
f) Richview TS to Manby TS 230 kV circuits: R1K, R2K, R13K, and R15K

The Cherrywood TS to Richview TS circuits, the Parkway TS to Richview TS circuits, and the Claireville TS to Richview TS circuits carry bulk transmission flows as well as serve local area station loads within the Sub-Region. These circuits are adequate[2] over the study period.

The Cherrywood TS to Agincourt TS circuit C10A is a radial circuit that supplies Agincourt TS and Cavanagh MTS. The circuit is adequate over the study period.

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

The Richview TS to Manby TS circuits supply the Manby TS 230/115 kV autotransformer station as well as Horner TS. With the Richview to Manby 230 kV Corridor Reinforcement in-service in 2023, the circuits will be adequate over the study period.

6.2 230/115 kV Autotransformers Facilities

The autotransformers at Manby TS and Leaside TS serve the 115 kV transmission network and local loads in Central Toronto. A 550 MW generation facility Portlands Energy Centre ("PEC") is situated in Central Toronto, connecting to the 115 kV transmission system at Hearn Switching Station ("SS").

The 230/115 kV autotransformers facilities in the region consist of the following elements:

a. Manby East TS 230/115 kV autotransformers: T7, T8, T9
b. Manby West TS 230/115 kV autotransformers: T1, T2, T12
c. Leaside TS 230/115 kV autotransformers: T11, T12, T14, T15, T16, T17

Manby East and West TS autos supply two distinct 115 kV load pockets. Manby East TS autos supply Runnymede TS, Fairbank TS, and Wiltshire TS through the Manby TS to Wiltshire TS circuits. Manby West TS autos normally supply the Strachan TS, John TS, and Copeland MTS through Manby TS to John TS circuits. The Manby TS autotransformer facilities are adequate over the study period.

Leaside TS autos supply the rest of the 115kV transformer stations – Basin TS, Bridgman TS, Carlaw TS, Cecil TS, Charles TS, Dufferin TS, Duplex TS, Esplanade TS, Gerrard TS, Glengrove TS, Main TS, and Terauley TS. The Leaside TS autotransformer facilities are adequate over the study period.

6.3 115 kV Transmission Facilities

The 115 kV transmission facilities in the Metro Toronto Region serve local station loads in the Central Toronto area and are connected to the rest of the grid via Manby TS and Leaside TS autotransformers. The 115 kV transmission facilities can be divided into nine main corridors summarized below.

a. Manby East TS x Wiltshire TS – Four circuits K1W, K3W, K11W, and K12W

[2] Adequate – means that current flows are with conductor or equipment thermal limits and all area bus voltages meet the Ontario Resource and Transmission Assessment Criteria (ORTAC) under normal and contingency conditions.

b. Manby West TS x John TS – Six circuits H2JK, K6J, K13J, K14J, D11J, and D12J
c. Leaside TS x Cecil TS – Three circuits L4C, L9C, and L12C
d. Leaside TS x Hearn SS – Six circuits H6LC, H8LC, H1L, H3L, H7L, and H11L
e. Leaside TS x Wiltshire TS – Four circuits L13W, L14W, L15, and L18W
f. Leaside TS x Duplex TS and Glengrove TS – Four circuits L5D, L16D, L2Y, and D6Y
g. Cecil TS x Esplanade TS – Two circuits C5E and C7E
h. John TS x Esplanade TS x Hearn SS – Three circuits H2JK, H9DE/D11J, and H10DE/D12J

The Manby East TS to Wiltshire TS 115 kV circuits supply Runnymede TS, Fairbank TS, and Wiltshire TS and were identified as requiring reinforcement in the 2016 Metro Toronto RIP. This work was completed in November 2018. With the completion of this work, the corridor circuits are adequate over the study period.

The Manby West TS to John TS 115 kV circuits supply Strachan TS, John TS and Copeland MTS. The corridor circuits are adequate over the study period.

The Leaside TS to Cecil TS 115 kV circuits and the Leaside TS to Hearn SS 115 kV circuits supply Basin TS, Carlaw TS, Cecil TS, Charles TS, Gerrard TS, and Main TS. The circuits are adequate over the study period.

The Leaside TS to Wiltshire TS corridor supply Bridgman TS and Dufferin TS. It has been recently reinforced with the addition of the L18W circuit in 2016 (Midtown transmission reinforcement). With the completion of this work the existing corridor circuits are adequate over the study period.

The Leaside TS to Duplex TS and Glengrove TS circuits (L5D, L16D, L2Y, and D6Y) are radial circuits that supply loads at Duplex TS and Glengrove TS. The circuits are adequate over the study period.

The Cecil TS to Esplanade TS circuits supply Terauley TS. The circuits are adequate over the study period.

The John TS to Esplanade TS and Hearn SS supply Esplanade TS. The circuits are adequate over the study period.

6.4 Step-Down Transformer Station Facilities

There are a total of 35 step-down transformers stations in the Toronto Region, connected to the 230 kV and 115 kV transmission network as listed below. The stations summer peak load forecast are given in Appendix D Table D-1.

Table 6-2: Toronto Step-Down Transformer Stations

230 kV Connected		115 kV Connected		
Agincourt TS	Leslie TS	Basin TS	Esplanade TS	Fairbank TS
Bathurst TS	Malvern TS	Bridgman TS	Gerrard TS	Copeland MTS
Bermondsey TS	Rexdale TS	Carlaw TS	Glengrove TS	John TS
Cavanagh MTS	Scarboro TS	Cecil TS	Main TS	Strachan TS
Ellesmere TS	Sheppard TS	Charles TS	Terauley TS	Horner TS
Fairchild TS	Warden TS	Dufferin TS	Wiltshire TS	Manby TS
Finch TS	Richview TS	Duplex TS	Runnymede TS	
Leaside TS				

With the construction of the second DESN at Runnymede TS (completed in 2018) and the second DESN at Horner TS (planned to be in-service by 2022), there will be adequate transformer station capacity over the study period.

6.5 Longer Term Outlook (2030-2040)

While the RIP was focused on the 2019-2029 period, the Study Team has also looked at longer-term loading between 2030 and 2040. The results indicate that the following facilities may be overloaded or reach capacity over this period.

- Manby West TS 230/115 kV autotransformers, which is limited by the lowest rated unit T12 in the fleet. T12 autotransformer replacement, planned to be completed by 2025, is expected to relieve this constraint.
- Leaside TS 230/115 kV autotransformers. This capacity need is based on the assumption that two of the three units at Portlands Energy Centre GS are out-of-service, and total plant generation is 160 MW. Post-contingency control action is currently available to resolve this issue by transferring Dufferin TS to Manby supply. Refer to Appendix D of 2019 Toronto IRRP ("Planning Study Results") for more details.
- Table 6.3 and 6.4 provide the adequacy summary of the transmission circuits and transformer stations potentially requiring relief within the 2030-2040 period.

Table 6-3: Longer Term Adequacy of Transmission Facilities

Facilities	Area MW Load (1)			MW Load Meeting Capability	Limiting Element	Limiting Contingency	Need Date
	2030	2035	2040				
115 kV Leaside TS x Wiltshire TS corridor	309	332	342	340	L15	L14W	2035-2040
115 kV Manby W TS x Riverside Jct. corridor	487	517	547	510	K13J	H2JK	2030-2035

(1) The sum of station's coincident summer peak load adjusted for extreme weather, excluding energy-efficiency savings, assuming normal supply configuration, without load transfer

Table 6-4: Longer Term Adequacy of Step-Down Transformer Stations

Facilities	Station MW Load [1]			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Fairbank TS	182	188	193	182	2030-2035
Sheppard TS	203	216	224	204	2030-2035
Strachan TS	167	182	193	169	2030-2035
Basin TS	85	91	95	88	2030-2035

(1) Station's non-coincident summer peak load, adjusted for extreme weather, excluding energy-efficiency savings

7 REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE TORONTO REGION AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses electrical infrastructure needs in the Toronto Region and plans to address these needs. The electrical infrastructure needs in the Toronto Region are summarized below in Table 7.1 and Table 7.2. Except for the Richview to Manby Reinforcement, these needs are primarily associated with the replacement of end-of-life equipment.

Table 7-1: Identified Near and Mid-Term Needs in Toronto Region

Section	Facilities	Need	Timing
7.1	Main TS	End-of-life of transformers T3 and T4	2021
7.2	H1L/H3L/H6LC/H8LC	End-of-life of overhead line section between Leaside 34 Jct. & Bloor St. Jct.	2023
7.3	L9C/L12C	End-of-life of overhead line section between Leaside TS & Balfour Jct.	2023
7.4	C5E/C7E	End-of-life underground cables between Esplanade TS & Terauley TS	2024
7.5	Richview TS to Manby TS 230 kV Corridor	Additional load meeting capability upstream of Manby TS (Richview TS to Manby TS 230 kV corridor)	2023
7.6	Manby TS	End-of-life of autotransformers T7, T9, T12, step-down transformer T13, and the 230 kV switchyard at Manby TS	2025
7.7	Bermondsey TS	End-of-life of transformers T3, T4 at Bermondsey TS	2025
7.8	John TS	End-of-life of T1, T2, T3, T4, T5, T6 transformers, 115 kV breakers, and LV switchgear at John TS	2026

Table 7-2: Identified Long-Term Needs in Toronto Region

Section	Facilities	Need	Timing
7.9.1	Fairbank TS	Station capacity exceeded	2030-2035
7.9.2	Sheppard TS	Station capacity exceeded	2030-2035
7.9.3	Strachan TS	Station capacity exceeded	2030-2035
7.9.4	Basin TS	Station capacity exceeded	2030-2035
7.9.5	115 kV Manby W TS x Riverside Jct. corridor	Manby TS x Riverside Jct section of circuit K13J overloaded for circuit H2JK contingency	2030-2035
7.9.6	Manby W TS Autotransformers	Autotransformer T12 overloaded for T1 or T2 contingency	2030-2035
7.9.7	115 kV Leaside TS x Wiltshire TS corridor	Leaside TS to Balfour Jct. section of circuit L15 overloaded for circuit L14W contingency	2035-2040
7.9.8	Leaside TS Autotransformers	Autotransformer T16 overloaded for circuit C15L or C17L contingency, assuming 160 MW at Portlands GS	2035-2040

7.1 Main TS: End-of-Life Transformers

7.1.1 Description

Main TS is a 115/13.8 kV transformer station serving the eastern part of Central Toronto including the Beaches and Danforth area. The station is electrically situated within the Leaside 115 kV zone, supplied via 115 kV circuits H7L/H11L (see Figure 7-1). Peak demand at Main TS has been on average 59 MW over the last 3 years and is expected to increase to 62 MW over the next 10 years.

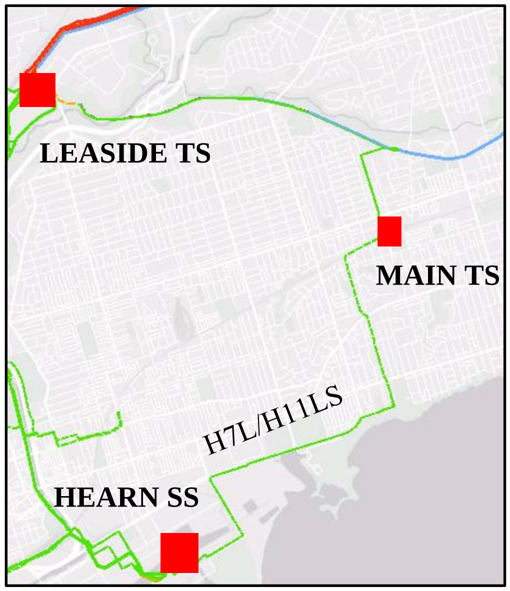

Figure 7-1: Main TS

The two transformers at Main TS (T3 and T4) are 46-51 years old 75 MVA units and are reaching their end-of-life. In addition, other equipment in the station, such as 115 kV line disconnect switches, current and voltage transformers, are also reaching their end-of-life.

7.1.2 Alternatives and Recommendation

The following alternatives were considered to address Main TS end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One’s obligation to provide reliable supply to the customers.
2. **Alternative 2 - Replace with similar type and size equipment as per current standard:** Under this alternative the existing transformers at Main TS are replaced with new 115/13.8 kV transformers. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.
3. **Alternative 3 - Converting Main TS to 230 kV operation:** This alternative would require replacing the existing transformers with new 230/13.8kV transformers and building a new 230kV supply to Main TS from either Warden TS or Leaside TS. The existing H7L/H11L circuits cannot be used as they are required for Hearn TS x Leaside TS use. This alternative is significantly more costly (3-4 times) compared to Option 2 as it would require building the new 230 kV supply in addition to replacing the transformers. It was therefore not considered further.
4. **Alternative 4 - Supplying Main TS switchgear from new transformers at Warden TS:** Under this alternative instead of replacing the existing aging transformers at Main TS, new 230/13.8 kV transformers will be installed at Warden TS, a 230/27.6 kV transformer station located approximately 4.5 km north-east of Main TS. This alternative is significantly more (3-4 times) costly compared to Option 2 due to the excessive amount of distribution cables required to connect the transformers at Warden TS to the switchgear at Main TS. It was therefore not considered further.

The Study Team recommends Alternative 2 as the technically preferred and most cost-effective alternative to refurbish Main TS. Further given the longer term potential for growth; need to provide system resiliency and flexibility; and insignificant incremental cost difference between 45/75 MVA and 60/100 MVA transformers, the Study Team recommends that Hydro One replace the existing transformers with larger 60/100 MVA units. The plan cost is estimated to be about $33 million, and is expected to in-service by end 2021.

7.2 H1L/H3L/H6LC/H8LC: End-of-Life Overhead Section (Leaside 34 Jct. to Bloor St. Jct.)

7.2.1 Description

The 115 kV circuits H1L/H3L/H6LC/H8LC provide connections between Leaside TS, Hearn SS, and Cecil TS, and supply transformer stations in the eastern part of central Toronto including Gerrard TS, Carlaw TS, and Basin TS. Based on their asset condition, conductors along the overhead section between Leaside 34 Jct. and Bloor St. Jct. are determined to be approaching their end-of-life. Figure 7.2 shows the location of the end-of-life section.

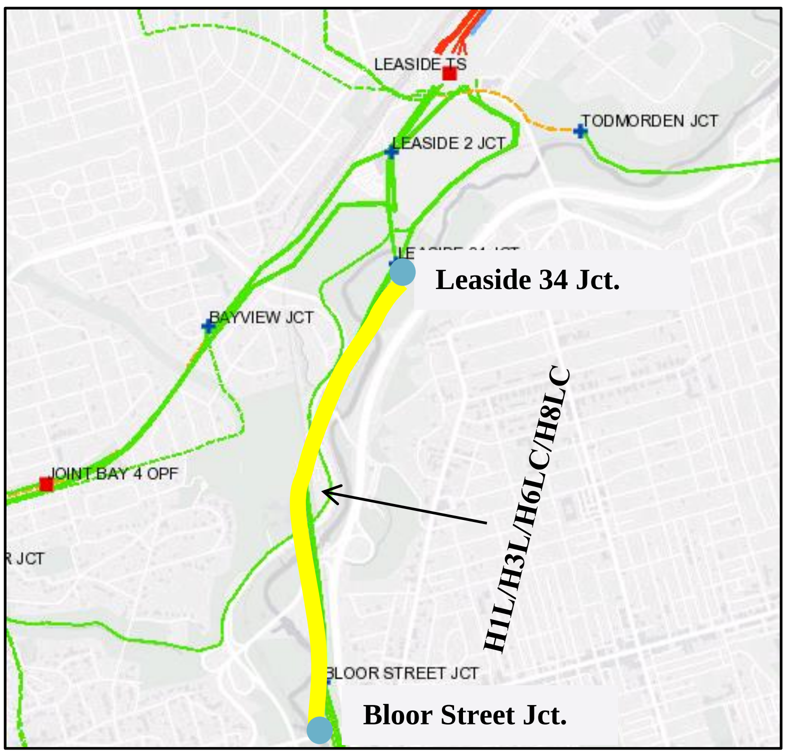

Figure 7-2: H1L/H3L/H6LC/H8LC Section between Leaside 34 Jct. and Bloor St. Jct.

7.2.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
2. **Alternative 2 – Refurbish the end-of-life overhead section as per current standard:** Under this alternative the existing end-of-life overhead section will be refurbished and the conductor will be replaced with largest size possible while retaining existing tower structures. This alternative addresses the end-of-life assets need, minimizes losses and maintains reliable supply to the customers in the area.
3. **Alternative 3 –Replace and rebuild line for future 230 kV operation:** Under this alternative the line would be rebuilt to 230kV standards so as to be able for future 230kV operation. This alternative would be significantly more costly than Alternative 2 and with no plans to utilize the line at the higher operating voltage, was rejected and not considered further.

The Study Team recommends that Hydro One proceed with Alternative 2 – the refurbishment of the end-of-life overhead section. The line refurbishment work is expected to be complete by 2023.

7.3 L9C/L12C: End-of-Life Overhead Section (Leaside TS to Balfour Jct.)

7.3.1 Description

The overhead section of 115 kV double circuit line L9C/L12C between Leaside TS and Balfour Jct. is over 80 years old and has been determined to be approaching its end-of-life. Figure 7.3 shows the location of the end-of-life section.

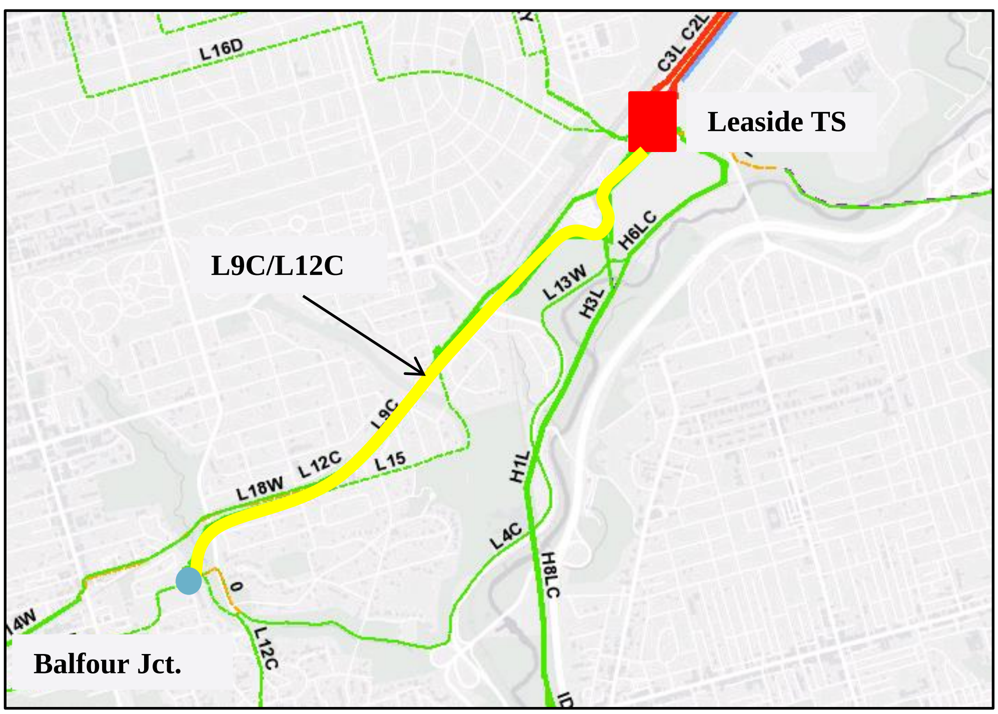

Figure 7-3: L9C/L12C Section between Leaside TS and Balfour Jct.

7.3.2 Alternatives and Recommendation

The following alternatives are considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
2. **Alternative 2 – Refurbish the end-of-life overhead section as per current standard:** Refurbish the end-of-life overhead section and replace conductors with the largest size possible while retaining existing tower structures. This alternative is recommended as it addresses the end-of-life assets need and maintains reliable supply to the customers in the area.

The Study Team recommends that Hydro One proceed with Alternative 2 – the refurbishment of the end-of-life overhead section of L9C/L12C between Leaside TS and Balfour Jct. The line refurbishment work is planned to be completed by 2023.

7.4 C5E/C7E: End-of-Life Underground Cables (Esplanade TS to Terauley TS)

7.4.1 Description

Circuits C5E and C7E between Esplanade TS to Terauley TS are 115 kV paper insulated low pressure oil filled underground transmission cables that provide a critical 115 kV supply to Toronto's downtown core and are partially routed along Lake Ontario.

These circuits, put into service in 1959, are among the oldest cable circuits in the Hydro One's transmission system. Based on condition test results, the cable jackets and paper insulation were found to be in deteriorated condition which can lead to overheating, oil leaks, and cable failure. Figure 7.3 shows the location of the end-of-life section.

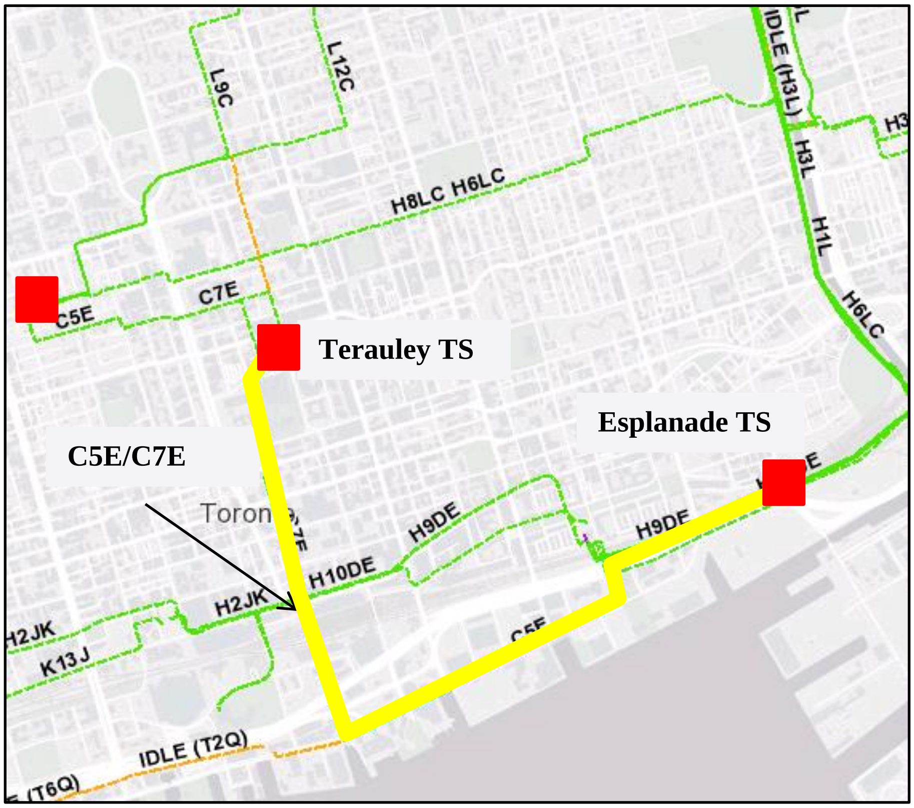

Figure 7-4: C5E/C7E Underground Cable Section between Esplanade TS and Terauley TS

7.4.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition. Failure to these cables can impact the power supply to critical facilities in Downtown Toronto. A large oil leak would have significant environmental impact and require costly environmental remediation.
2. **Alternative 2 - Replace with similar type and size equipment as per current standard:** Under this alternative, the existing cables will be replaced with new 230 kV rated cables. The 230 kV rated cables have higher insulation and are less prone to failure. This alternative is recommended as it addresses the end-of-life assets need and maintains reliable supply to the customers in the area.

The Study Team recommends that Hydro One proceed with Alternative 2 – the replacement of the end-of-life underground cables between Esplanade TS and Terauley TS. Hydro One is currently proceeding with detailed estimation of options including tunneling for evaluating the most appropriate routes and construction options. This will be an input for public consultations to obtaining permit and necessary approvals along with environmental assessments. A final route and installation option will be selected as part of the open EA process. The cable refurbishment work is planned to be completed by 2024.

7.5 Richview TS to Manby TS 230 kV Corridor

7.5.1 Description

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto. Along this corridor there are two double-circuit 230 kV lines R1K/R2K and R13K/R15K. Together with circuit R24C between Richview TS and Cooksville TS, this corridor also supplies the load in the southern Mississauga and Oakville areas via Manby TS. The first cycle Metro Toronto Regional Infrastructure Plan has identified the need to increase transfer capability of this transmission corridor to support the continuous load growth in these areas.

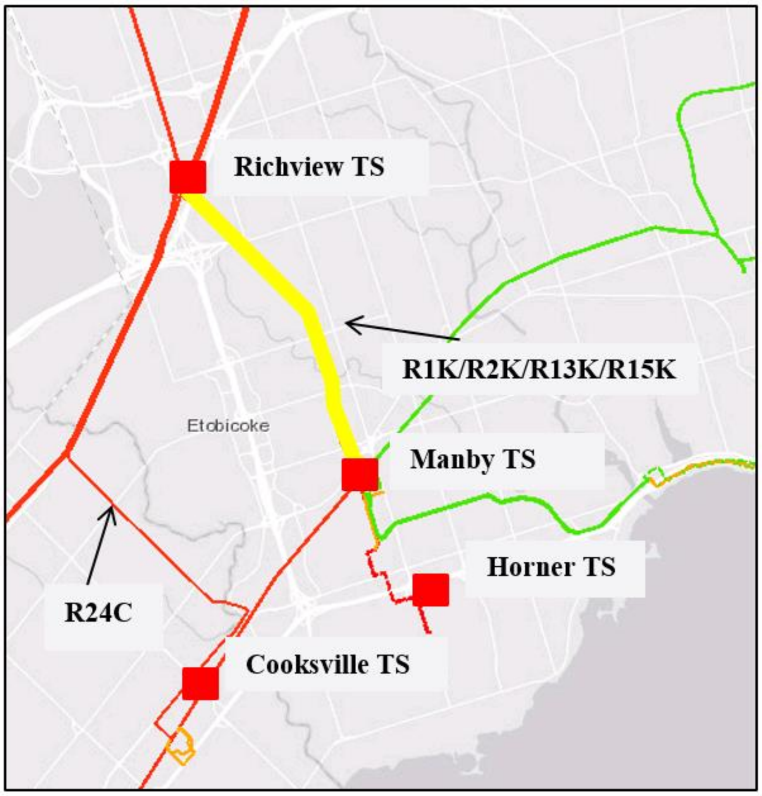

Figure 7-5: Richview TS to Manby TS 230 kV Corridor

7.5.2 Alternatives and Recommendation

A detailed assessment of the Richview TS to Manby TS corridor need was carried out in the Appendix F of the Toronto IRRP to reconfirm the capacity need of this corridor based on the changes in assumptions and the up-to-date load forecast. The assessment confirmed the need, and the Study Team continues to recommend that the reinforcement of the Richview TS to Manby TS 230 kV circuits to be completed as soon as possible.

Evaluation of alternatives was completed by the Study Team as documented in the 2015 Toronto Regional Infrastructure Plan. As per the Study Team's recommendation, Hydro One is proceeding with the Richview TS to Manby TS 230 kV transmission reinforcement project, which will be carried out in two phases:

- **Phase 1:** This phase covers rebuilding the existing idle 115 kV overhead line on the transmission corridor between Richview TS and Manby TS to 230 kV standards. The new line will operate in parallel with the existing four 230 kV circuits from Richview TS to Manby TS, which will initially be reconfigured to create two "supercircuits." This configuration avoids the need to build new terminations and new breakers at Manby TS. The IRRP noted the need for Phase 1 is in 2021 but the expected in-service is Q4 2023. Figure 7-6 below shows the transmission configuration after Phase 1 is completed.

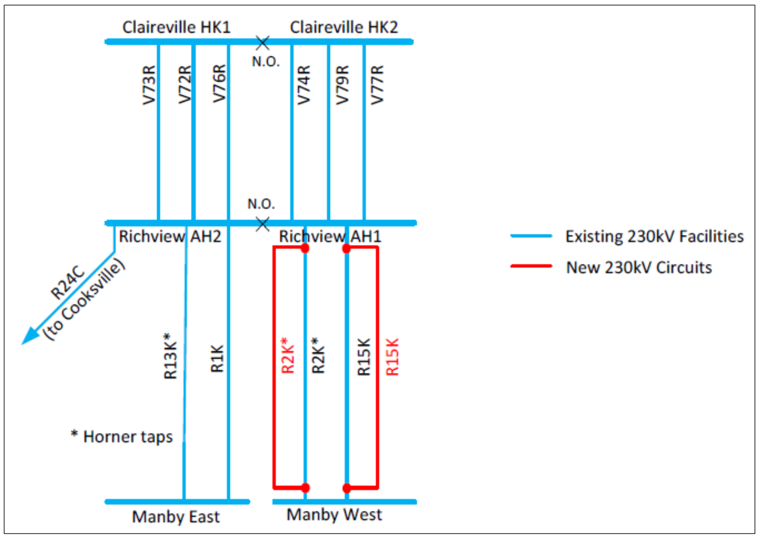

Figure 7-6: Richview TS to Manby TS 230 kV Corridor – Phase 1

i. **Phase 2:** In the second phase the super circuits will be unbundled with one new circuit connected to Manby West and one to Manby East with new termination installed at Manby TS. At Richview TS, the new circuits will be tapped to existing 230 kV circuits V73R and V79R from Claireville TS. This configuration allows Richview TS to be bypassed and permits continued supply to Manby TS should there be an emergency at Richview TS. The timing of Phase 2 will be planned to coincide with Manby TS end of life refurbishment, all of which is planned to be complete by 2025. Figure 7-7 below shows the transmission configuration after Phase 2 is completed. Note that the nomenclature shown for the new circuits are for illustrative purposes only and subject to change.

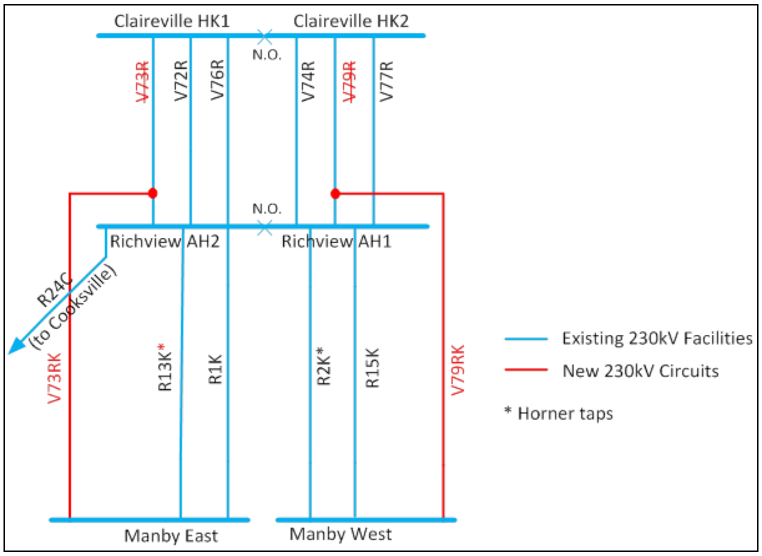

Figure 7-7: Richview TS to Manby TS 230 kV Corridor – Phase 2

7.6 Manby TS: End-of-Life Transformers and 230 kV Switchyard

7.6.1 Description

Manby TS is a major bulk electric switching and autotransformer station in the Toronto region. Station facilities include the Manby West and Manby East 230 kV and 115 kV switchyards, six 230/115 kV autotransformers (T1, T2, T7, T8, T9, T12), and six 230/27.6 kV step-down transformers supplying three DESNs (T3/T4, T5/T6, T13/T14).

The Manby TS autotransformers T7, T9, and T12 and step down transformer T13 are about 50 years old and all four have been identified to be nearing the end of their useful life and require replacement in the next 5 years. All three DESNs at Manby TS are currently at capacity, and the new second DESN at nearby Horner TS (I/S 2022) is expected to pick-up the load growth in the area.

The 230 kV oil breakers have also been identified to be nearing end-of-life and require replacement over the next 5-year period. As part of breaker replacement work, the 230 kV Manby West and Manby East switchyards will be modified and an additional three breakers added to terminate the two new circuits to Richview TS described above in Section 7.5 under Phase 2 for the Richview TS to Manby TS corridor reinforcement.

Figure 7-8: Manby TS

7.6.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability for customers.
2. **Alternative 2 - Replace the end-of-life transformers with similar type and size equipment as per current standard, and rebuild/modify the 230 kV switchyard:** This alternative involves the replacement of Manby East T7, T9, and Manby West T12 autotransformers with 250 MVA units; Manby T13 DESN transformers with 75/93 MVA unit; replacement of end-of-life 230 kV oil breakers; as well as 230 kV switchyard modification and installing three new breakers to accommodate the new circuits to Richview TS (as part of the Richview TS to Manby TS Corridor Reinforcement). This alternative is recommended as it addresses the end-of-life asset needs and maintains reliable supply to customers in the area by:
    - reducing the risk of breaker failure events at Manby TS;
    - providing relief to the autotransformer capacity constraints in the long-term at Manby West TS by replacing the lowest rated unit T12; and
    - connecting the new circuits to Richview TS to support the continuous load growth in these areas.

The Study Team recommends that Hydro One proceed with Alternative 2 – the end-of-life transformer replacement and rebuilding of the Manby TS 230 kV switchyard. The project is expected to be completed by 2025.

7.7 Bermondsey TS: End-of-Life Transformers

7.7.1 Description

Bermondsey TS along with Ellesmere TS, Scarborough TS, Sheppard TS and Warden TS supply the Scarborough area and comprises of two DESNs. The T1/T2 DESN was built in 1990, has 6 feeders, an LTR of 185.8 MW and supplied a summer 2018 peak load of 43 MW. The T3/T4 DESN was built in 1965, has 12 feeders, an LTR of 162.5 MW and supplied a 2018 summer peak load of 117 MW.

The T3 and T4 transformers are about 55 years old, have been identified as nearing the end of their useful life and requiring replacement in the next 5 years.

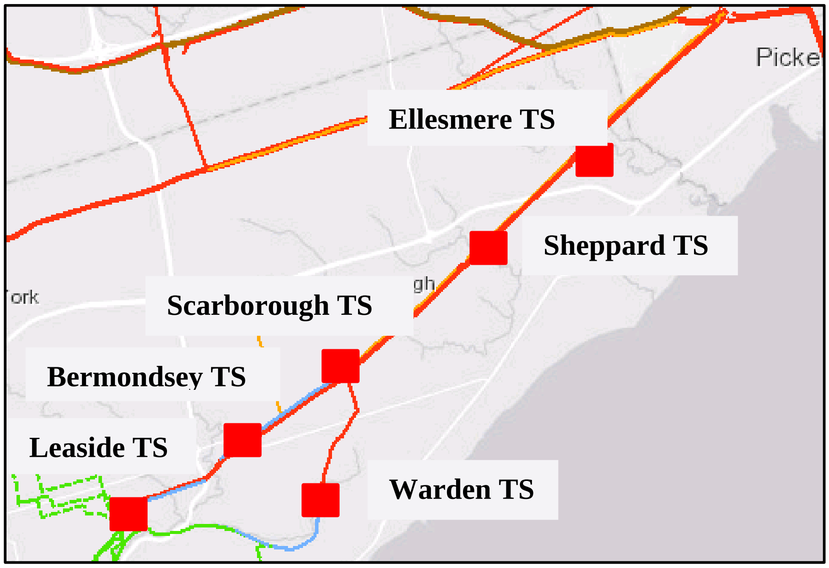

Figure 7-9: Bermondsey TS and Surrounding Stations

7.7.2 Alternatives and Recommendation

The recommendation for the end of life replacement is as follows:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
2. **Alternative 2 - Decommission the T3/T4 DESN at its end-of-life:** This alternative is not viable as there would be insufficient feeder capacity to supply the existing load. It was not considered further.
3. **Alternative 3 - Downsize (replace with smaller 83 MVA transformers):** This alternative would require extensive feeder transfers, and reconfiguration of the station including addition of new feeders on the T1/T2 DESN. The cost of the station reconfiguration work is expected to exceed $5M and significantly exceeds the $500-600k cost savings resulting from using the smaller size transformers.
4. **Alternative 4 - Replace with similar type and size equipment as per current standard:** This alternative is recommended as this is the most cost effective option, and addresses the end-of-life assets need and maintains reliable supply to the customers in the area.

Considering above options, the Study Team recommends that Hydro One proceed with Alternative 4 – the refurbishment of the T3/T4 DESN of Bermondsey TS and build to current standard. The refurbishment plan is expected to be in-service by 2025.

7.8 John TS: End-of-Life Transformers, 115 kV Breakers, and LV Switchgear

7.8.1 Description

John TS (also referred to as Windsor TS) is connected to the 115 kV Manby West system and supplies the western half of City of Toronto's downtown district. Station facilities include a 115 kV switchyard and six 115/13.8 kV step-down transformers (T1, T2, T3, T4, T5, T6) supplying six Toronto Hydro low voltage metalclad switchgears. The summer 10-day LTR is 311 MW. The station's 2018 actual non-coincident summer peak load (adjusted for extreme weather) was about 261 MW.

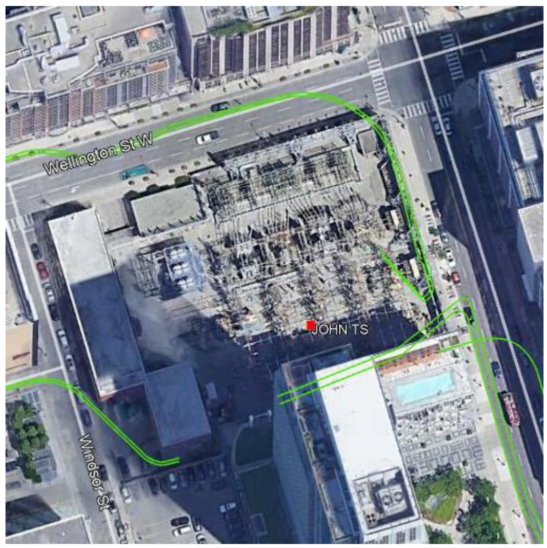

Figure 7-10: John TS

The T1 and T4 step-down transformers at John TS, both over 50 years old and in poor condition, were replaced in 2019. The step down transformers (T2, T3, T5 and T6) which range in age from 44-50 years are also at, or nearing, end of life. It is expected that these transformers will need to be replaced in the next 3-5 years. The 115 kV breakers are mostly oil type and are about 44 years old. They are also nearing end of useful life and are expected to require replacement in the next 5-10 years.

Toronto Hydro has also identified the need for renewal of their switchgear facilities at John TS. This work will be done over multiple phases and is expected to take 20-25 years to fully complete. The first phase involves relocating the feeders from switchgear at John TS to new switchgear at Copeland MTS so as to permit of the replacement of switchgear at John TS. The presence of Copeland MTS, which went into service in 2019, enables the switchgear replacement due to the capacity (transformation and feeder positions) at Copeland MTS that are not available at John TS or other neighboring stations. The load transfer to Copeland MTS is necessary to reduce load at John TS to facilitate the transformer and switchgear replacement work at John TS.

Toronto Hydro plan to initiate the switchgear renewal process starting with the Windsor Station A5-A6 and the A3-A4 metalclad switchgear buses. These buses are expected to be replaced by the new A19-A20 bus in 2022-2023 and later followed by A21-A22 bus. Hydro One will replace associated low voltage transformer breaker disconnect switches and cables in coordination with Toronto Hydro.

7.8.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.

2. **Alternative 2 – Reducing the Number of Transformers from Six to Four Units:** As part of the John TS refurbishment work and the consequent reduction in loading at the station, Hydro One investigated the opportunity for reducing the number of 115/13.8 kV transformer units at John TS from the current six units to four units. Hydro One assessed with Toronto Hydro the feasibility of the following two options:
   i. Reducing the number of switchgear pairs in the station from the current six to four to match the supply from four transformers. The assessment concluded that Copeland MTS has only enough feeder positions available to pick up one bus (typically 14-16 feeders) from John TS, and therefore there are no additional feeder positions available at Copeland MTS to further eliminate another bus at John TS. As such this option is not feasible.
   ii. Reducing the number of transformer supply points to the existing six switchgear pairs through switchgear bus bundling (while not reducing the number of feeder positions at the station). This involved looking at opportunities of electrically joining presently distinct switchgear pairs while at the same time respecting equipment ratings. No opportunities were found that would respect equipment ratings. If opportunities that would respect equipment ratings had been found these would then be reviewed based upon operational factors involving customers impacted by a contingency, restoration times, etc. A first review of these operational factors found that Toronto Hydro's ability to perform bus load transfers would be limited than what it is today and its restoration times would be lengthened compared to what exists today due to the increased concentration of customers per bus. Given the lack of opportunities and the negative operational impacts even if opportunities were to be found, this option is not feasible.
   iii. Consistent with the IRRP load forecast, Toronto Hydro has cited continued electricity demand along with higher reliability from customers for new connections to its distribution system in the downtown core. The growth in new connections coupled with Toronto Hydro's distribution system for reliable service is leading to the demand for feeder positions outpacing the peak demand growth. Six switchgear pairs along with six transformer supply points are still required for John/Windsor TS.

   Based on the findings of above assessments, this alternative is not viable as Toronto Hydro feeder requirements are such that all of the six transformers are needed to supply load in the area via the six pairs of Toronto Hydro buses as described above.

3. **Alternative 3 - Similar Connection Arrangement with 60/100 MVA Transformers:** This alternative is recommended as it addresses the end-of-life assets need and maintains reliable supply

to the customers in the area. This alternative involves the replacement of the remaining T2, T3 (45/75 MVA), and T5, T6 (75/125 MVA) transformers with 60/100 MVA units, replacement of the LV switchgear in coordination with Toronto Hydro, and replacement of the existing oil filled breakers with SF6 breakers in the 115 kV switchyard. Minor modifications may be made (to the extent practically possible) to improve operational flexibility under outage conditions. Several options as described below were considered into the scope of the John TS refurbishment:

i. Downsize (replace with smaller size transformers): The renewal of John TS switchgear facilities is expected to be completed over multiple phases within the next 20-25 years. Over this time period, the load of an existing switchgear will be transferred from one transformer winding pairs to another to connect to the new switchgear. Since some of the switchgear is heavily loaded, all of the transformer windings should be able to handle the maximum load of a single switchgear (i.e., 3000 Amps). For this reason, downsizing of John TS transformers is not viable.

ii. Rebuild/reconfigure the 115 kV switchyard to a "Breaker-and-Half" configuration: The existing 115 kV breakers and buses are currently arranged in a ring-bus configuration and consideration was given to rebuilding and reconfiguring the 115 kV switchyard using a breaker and half arrangement. However, this alternative is not viable due to physical space constraints and clearances required for equipment and personnel safety. Although, practically constrained, this option will also require rerouting and retermination of high voltage cables and the cost of investment required for this reconfiguration significantly outweigh the incremental benefits.

The Study Team therefore recommends that Hydro One to proceed with Alternative 3 as described above. The John TS refurbishment plan is expected to be in service by 2026.

7.9 Long-Term Capacity Needs

A number of longer term capacity needs have been identified as described in Section 6.5 and Table 7.2. The Study team recommends that these needs be monitored and evaluated in future planning cycles. No investment is required at this time due to the forecast uncertainty and the longer-term timing of need. Preliminary comments are given below.

7.9.1 Fairbank TS Capacity Need

Fairbank TS load is expected to exceed LTR within the 2030-2035 time period. Consideration may be given to load transfer to the neighboring Runnymede TS. The Study Team recommends reviewing the loading in the next planning cycle.

7.9.2 Sheppard TS Capacity Need

Sheppard TS is also forecast to exceed capacity within the 2030-2035 time period. Consideration may be given to utilizing the idle winding on transformers T1/T2. The Study Team recommends reviewing the loading in the next planning cycle.

7.9.3 Strachan TS Capacity Need

Strachan TS is forecast to exceed capacity within the 2030-2035 time period. Consideration maybe given to provide relief to Strachan TS through permanent load transfers to Copeland MTS and/or John TS. The Study Team recommends reviewing the loading in the next planning cycle.

7.9.4 Basin TS Capacity Need

Basin TS is located in the Portlands area in Downtown Toronto. The need for additional capacity at Basin TS is expected to arise in the long-term (within the 2030-2035 time period). The timing of the need is dependent on the pace of development in the area. Physical space is available at the current Basin TS site to plan and build a second DESN to meet long term needs.

The City of Toronto is planning the re-development of the Portlands. The area may see additional load beyond that which has been included in the present forecasts. The timing of any new needs will depend upon the timing of the City's plan.

However, the City's current re-development plans will end the continued operation of Basin TS and several high voltage lines in their current locations in the Portlands. This will significantly impact both Hydro One infrastructure and Toronto Hydro infrastructure within and outside of Basin TS. No sites for a replacement transformer station or high voltage line routes have been identified by the City.

Hydro One and Toronto Hydro have requested the City to revise its plans so as to avoid the conflicts with Basin TS and high voltage lines. Hydro One and Toronto Hydro have also joined others in a legal appeal of the City's land plans.

Given the appeal and lack of information currently available to Hydro One and Toronto Hydro from the City, the Study Team recommends that Hydro One and Toronto Hydro continue to monitor the situation and update the Study Team as appropriate. Plans for supplying the Portlands area will be developed as more information becomes known.

7.9.5 Manby West TS to Riverside Jct. Corridor Capacity Need

The Manby TS x Riverside Jct. section of K13J/K14J is potentially overloaded under certain contingency conditions within the 2030-2035 time period. Consideration may be given to reconductor circuit with a higher ampacity conductor. The Study Team recommends reviewing the loading in the next planning cycle.

7.9.6 Manby West TS Autotransformers T12 Capacity Need

Manby West TS 230/115 kV autotransformers is restricted by the lowest rated unit T12 in the fleet, and is potentially overloaded within the 2030-2035 time period, following T1 or T2 contingency. T12 autotransformer replacement, planned to be completed by 2025, is expected to provide relieve to this constraint and meet the capacity requirement at Manby West TS autotransformers facility. See Section 7.5 for more details.

7.9.7 Leaside TS to Wiltshire TS Corridor Capacity Need

The Leaside TS x Balfour Jct. section of the underground 115 kV circuit L15, connecting Leaside TS and Wiltshire TS, is potentially overloaded in the long-term within the 2035-2040 time period. The Study Team determines that no further investment is required to address this need at this time due to the level of uncertainties and amount of lead time available. This need will be reevaluated in the next planning cycle.

7.9.8 Leaside TS Autotransformers T16 Capacity Need

Leaside TS autotransformer T16 is potentially overloaded in the long-term within the 2035-2040 time period, following circuit C15L or C17L contingency, assuming that two of the three units at Portlands Energy Centre GS are out-of-service, and total plant generation is 160 MW. Post-contingency control action is currently available to resolve this issue by transferring Dufferin TS to Manby supply. The Study Team determines that no further investment is required to address this need at this time due to the level of forecast uncertainty and amount of lead time available. The Study Team recommends reviewing the loading in the next planning cycle.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE TORONTO REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 8-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1: Recommended Plans in Toronto Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate(1)
1	Main TS: End-of-life of transformers T3/T4	Replace the end-of-life transformers with similar type and size equipment as per current standard	2021	$33M
2	H1L/H3L/H6LC/H8LC: End-of-life of Leaside Jct. to Bloor St. Jct. overhead section	Refurbish the end-of-life H1L/H3L/ H6LC/H8LC section	2023	$11M
3	L9C/L12C: End-of-life of Leaside TS to Balfour Jct. overhead section	Refurbish the end-of-life L9C/L12C section	2023	$3M
4	C5E/C7E: End-of-life of underground cables between Esplanade TS and Terauley TS	Replace the end-of-life C5E/C7E cables	2024	$128M
5	Richview TS to Manby TS 230 kV Corridor Reinforcement	Replace existing idle 115 kV double circuit line with new 230 kV double circuit line between Richview TS and Manby TS	2023	$21M
6	Manby TS: End-of-life of autotransformers (T7, T9, T12), step-down transformer (T13), and the 230 kV switchyard	Replace the end-of-life transformers with similar type and size equipment as per current standard, and refurbish/reconfigure Manby 230 kV switchyard	2025	$85M
7	Bermondsey TS: End-of-life of transformers T3/T4	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	$27M
8	John TS: End-of-life of transformers (T1, T2, T3, T4, T5, T6), 115 kV breakers, and LV switchgear	Replace with similar type and size equipment as per current standard	2026	$102M

(1) Budgetary estimates are provided for Hydro One's portion of the work

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 8-1 while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

9 REFERENCES

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[3] **Toronto Region Scoping Assessment (2018)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/Toronto-Scoping-Assessment-Outcome-Report-February-2018.pdf?la=en

[4] **Toronto Integrated Regional Resource Plan (2019)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/engagement/Toronto-IRRP-20190809-Report.pdf?la=en

[5] **Toronto Integrated Regional Resource Plan - Appendices (2019)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/engagement/Toronto-IRRP-Appendices.pdf?la=en

APPENDIX A. STATIONS IN THE 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/L15/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/L15
Dufferin TS T2/T4	115/13.8	L13W/L15
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
Fairchild TS T3/T4	230/27.6	C18R/C20R

Station (DESN)	**Voltage (kV)**	**Supply Circuits**
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 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	D11J, D12J, H9DE, H10DE	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 Bridgman x Wiltshire	L13W, L14W, L15, L18W	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 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	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
Alectra Utilities	Agincourt TS	Dx
	Fairchild TS	Dx
	Finch TS	Dx
	Leslie TS	Dx
	Richview TS	Dx
Elexicon Energy Inc.	Malvern TS	Dx
	Sheppard TS	Dx

APPENDIX D. TORONTO REGION LOAD FORECAST

Table D-1: Toronto IRRP Load Forecast, without the Impacts of Energy-Efficiency Savings

		Near & Mid-Term Forecast												Long-Term Forecast		
Area & Station	**LTR (MW)**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2035**	**2040**
North 230 kV																
Agincourt TS	174	92	95	98	100	101	102	103	104	104	105	106	106	107	110	114
Bathurst TS	334	210	220	226	229	231	233	235	236	238	239	242	245	247	265	274
Cavanagh MTS	157	91	92	93	94	95	95	95	96	97	98	98	99	100	108	112
Fairchild TS	346	235	237	239	241	243	245	247	249	250	250	252	254	255	260	265
Finch TS	365	249	254	258	260	261	262	263	265	267	269	271	272	273	279	284
Leslie TS	325	233	241	249	250	254	255	258	260	261	262	264	265	266	283	293
Malvern TS	176	83	84	85	86	86	86	87	88	88	91	93	95	96	103	106
East 230 kV																
Bermondsey TS	348	148	152	154	156	159	160	161	162	164	164	165	165	165	166	172
Ellesmere TS	189	124	126	128	129	130	131	131	132	133	133	134	134	134	135	138
Leaside TS	202	151	156	160	163	164	165	165	167	168	168	169	169	169	171	178
Scarboro TS	340	204	207	209	211	212	213	214	216	218	218	218	219	219	230	236
Sheppard TS	205	141	144	146	148	148	150	151	153	153	153	156	159	161	171	177
Warden TS	182	106	108	109	110	111	112	113	113	113	117	120	122	124	132	136
West 230 kV																
Horner TS	365	133	137	138	140	140	142	143	144	145	149	154	158	161	177	187
Manby TS	226	191	202	205	211	212	215	216	217	219	220	222	224	226	240	251
Rexdale TS	187	123	124	125	125	127	127	129	129	129	129	127	127	125	118	110
Richview TS	460	227	213	217	219	220	222	223	224	226	224	222	219	218	213	204
Leaside 115 kV																
Basin TS	88	65	71	75	76	77	77	78	79	79	81	83	84	85	91	95
Bridgman TS	212	154	154	156	157	157	160	161	161	162	163	164	165	167	180	186
Carlaw TS	73	66	67	67	67	68	68	69	69	70	70	70	70	72	72	72
Cecil TS	215	162	170	175	177	179	181	182	183	184	182	180	178	177	177	177
Charles TS	211	145	151	154	155	156	158	158	159	159	161	164	166	167	175	176
Dufferin TS	170	136	121	124	125	125	126	127	128	130	134	135	139	142	152	156
Duplex TS	128	99	101	100	98	97	94	94	96	97	98	99	100	102	108	113
Esplanade TS	187	162	142	145	146	146	148	148	149	150	149	147	146	143	147	148
Gerrard TS	102	35	44	47	49	49	50	50	50	51	51	51	51	51	52	53
Glengrove TS	88	48	50	50	51	51	51	51	51	51	52	54	55	56	60	62
Main TS	77	56	57	57	58	59	59	59	60	60	62	62	63	64	65	65
Terauley TS	249	175	188	194	190	188	188	191	191	191	190	187	185	184	181	182
Manby E 115 kV																
Fairbank TS	182	141	125	132	135	139	142	144	145	146	147	148	149	149	154	158
Runnymede TS	219	96	136	141	143	143	146	146	148	148	149	149	151	151	158	164
Wiltshire TS	133	55	71	72	72	72	73	73	73	75	75	76	76	76	83	86
Manby W 115 kV																
Copeland MTS	130	0	0	52	93	93	94	94	96	96	98	99	100	102	107	112
John TS	314	263	266	215	201	202	203	204	206	206	210	212	215	218	228	242
Strachan TS	169	139	143	145	146	147	147	149	149	150	155	159	163	167	182	193

Table D-2: Toronto Non-Coincident Load Forecast, without the Impacts of Energy-Efficiency Savings

		Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
Area & Station	**LTR (MW)**	**2018 (1)**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2035**	**2040**
North 230 kV																
Agincourt TS	174	112	115	119	121	122	124	125	126	126	127	128	128	130	133	138
Bathurst TS	334	227	238	244	248	250	252	254	255	257	258	262	265	267	287	296
Cavanagh MTS	157	108	109	110	112	113	113	113	114	115	116	116	117	119	128	133
Fairchild TS	346	268	270	272	274	277	279	281	284	285	285	287	289	290	296	302
Finch TS	365	290	296	301	303	304	305	306	309	311	313	316	317	318	325	331
Leslie TS	325	233	241	249	250	254	255	258	260	261	262	264	265	266	283	293
Malvern TS	176	105	106	108	109	109	109	110	111	111	115	118	120	122	130	134
East 230 kV																
Bermondsey TS	348	160	164	166	169	171	173	173	175	177	177	178	178	178	179	186
Ellesmere TS	189	124	126	128	129	130	131	131	132	133	133	134	134	134	135	138
Leaside TS	202	163	169	174	177	178	179	179	181	182	182	183	183	183	186	194
Scarboro TS	340	222	225	227	229	231	232	233	235	237	237	237	238	238	250	257
Sheppard TS	205	178	182	184	187	187	189	191	193	193	193	197	201	203	216	224
Warden TS	182	123	125	126	127	129	130	131	131	131	135	139	141	144	153	157
West 230 kV																
Horner TS (2)	365	141	145	146	148	193	199	202	204	208	213	221	228	234	268	292
Manby TS (2)	226	245	258	262	269	225	225	225	225	225	225	225	225	225	225	225
Rexdale TS	187	136	138	139	139	141	141	143	143	143	143	141	141	139	131	122
Richview TS	460	279	263	268	270	271	274	275	276	279	276	274	270	269	263	252
Leaside 115 kV																
Basin TS	88	65	71	75	76	77	77	78	79	79	81	83	84	85	91	95
Bridgman TS	212	154	154	156	157	157	160	161	161	162	163	164	165	167	180	186
Carlaw TS	73	66	67	67	67	68	68	69	69	70	70	70	70	72	72	72
Cecil TS	215	166	174	179	181	183	185	186	187	188	186	184	182	181	181	181
Charles TS	211	145	151	154	155	156	158	158	159	159	161	164	166	167	175	176
Dufferin TS	170	136	120	123	124	124	125	126	127	129	133	134	138	141	151	155
Duplex TS	128	99	101	100	98	97	94	94	96	97	98	99	100	102	108	113
Esplanade TS	187	163	143	146	147	147	149	149	150	151	150	148	147	144	148	149
Gerrard TS	102	37	46	49	51	51	52	52	52	54	54	54	54	54	55	56
Glengrove TS	88	51	53	53	54	54	54	54	54	54	55	57	58	59	63	65
Main TS	77	60	61	61	63	64	64	64	65	65	67	67	68	69	70	70
Terauley TS	249	175	188	194	190	188	188	191	191	191	190	187	185	184	181	182
Manby E 115 kV																
Fairbank TS	182	171	151	159	164	169	173	176	177	178	179	181	182	182	188	193
Runnymede TS	219	96	136	141	143	143	146	146	148	148	149	149	151	151	158	164
Wiltshire TS	133	56	74	75	75	75	76	76	76	78	78	79	79	79	86	90
Manby W 115 kV																
Copeland MTS	130	0	0	52	93	93	94	94	96	96	98	99	100	102	107	112
John TS	314	264	267	217	203	204	205	206	208	208	212	214	217	220	230	244
Strachan TS	169	139	143	145	146	147	147	149	149	150	155	159	163	167	182	193

(1) Non-coincident station peak, adjusted to extreme weather
(2) Load transferred to the new Horner TS DESN #2 in 2022

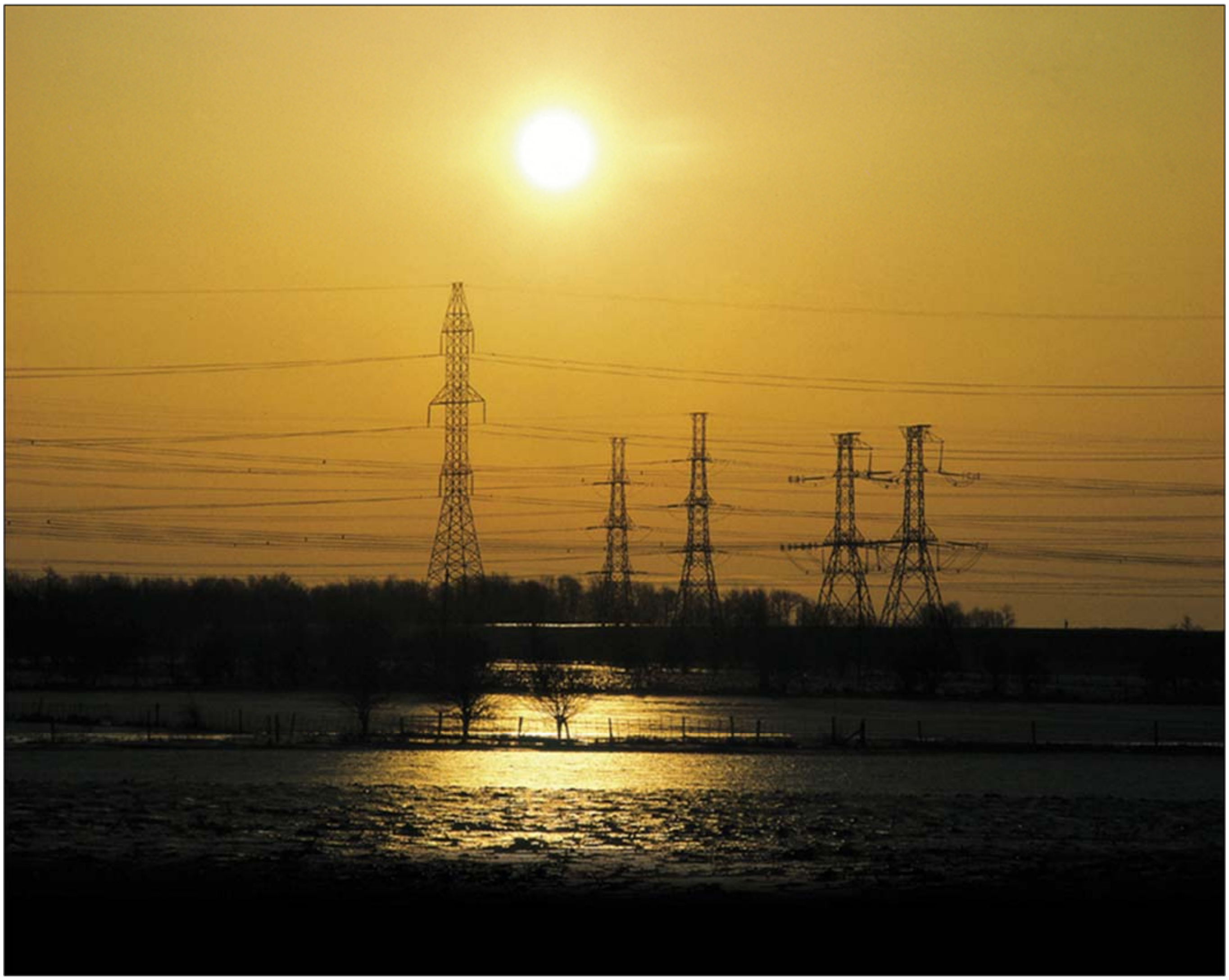
Table D-3: Toronto IRRP Load Forecast, with the Impacts of Energy-Efficiency Savings

		Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
Area & Station	**LTR (MW)**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2035**	**2040**
North 230 kV																
Agincourt TS	174	91	94	96	98	99	100	100	101	101	102	102	102	103	105	108
Bathurst TS	334	208	217	222	225	226	227	229	229	231	231	233	235	237	252	260
Cavanagh MTS	157	90	91	92	92	93	93	93	93	94	95	95	95	96	103	107
Fairchild TS	346	232	233	234	236	237	238	239	241	241	240	241	242	242	244	249
Finch TS	365	247	251	254	256	256	256	257	258	260	261	263	263	263	267	272
Leslie TS	325	230	237	244	245	248	248	250	251	252	252	253	253	253	266	276
Malvern TS	176	82	83	84	85	84	84	85	86	86	88	90	92	93	99	101
East 230 kV																
Bermondsey TS	348	146	150	151	153	155	156	156	157	159	158	159	158	157	157	162
Ellesmere TS	189	123	124	126	127	127	128	128	128	129	128	129	129	128	128	131
Leaside TS	202	149	154	157	160	160	161	160	162	162	162	162	162	161	161	168
Scarboro TS	340	202	204	206	208	208	208	209	210	212	211	211	211	211	219	225
Sheppard TS	205	140	141	143	145	144	146	146	148	148	147	150	152	153	161	167
Warden TS	182	105	106	107	108	109	109	110	109	109	113	115	117	118	125	129
West 230 kV																
Horner TS	365	132	135	136	138	137	139	139	140	141	144	148	152	154	168	177
Manby TS	226	189	199	202	207	208	210	210	211	212	212	214	215	216	227	238
Rexdale TS	187	121	122	123	122	124	123	125	124	124	123	121	120	118	110	102
Richview TS	460	224	209	213	214	215	216	216	216	218	215	213	209	207	200	192
Leaside 115 kV																
Basin TS	88	64	70	74	75	75	75	76	77	76	78	80	80	81	86	90
Bridgman TS	212	152	151	153	154	153	156	156	156	156	157	157	157	159	169	175
Carlaw TS	73	62	63	63	63	64	63	64	64	65	64	64	64	66	65	65
Cecil TS	215	160	167	172	174	175	176	177	177	178	175	173	170	169	167	167
Charles TS	211	143	149	151	152	152	154	153	154	153	155	157	158	159	165	166
Dufferin TS	170	134	119	122	123	122	123	123	124	126	129	130	133	135	143	147
Duplex TS	128	98	99	98	96	95	91	91	93	94	94	95	95	97	102	106
Esplanade TS	187	160	140	142	143	143	144	144	144	145	144	141	140	136	139	140
Gerrard TS	102	32	41	43	45	45	46	46	46	47	46	46	46	46	46	47
Glengrove TS	88	47	49	49	50	50	50	49	49	49	50	52	52	53	56	58
Main TS	77	55	56	56	57	58	57	57	58	58	60	59	60	61	61	61
Terauley TS	249	173	185	190	186	184	183	185	185	184	183	179	177	175	171	172
Manby E 115 kV																
Fairbank TS	182	139	123	130	132	136	138	140	141	141	142	142	143	142	146	149
Runnymede TS	219	95	134	139	140	140	143	142	144	143	144	144	145	144	150	155
Wiltshire TS	133	54	70	71	71	70	71	71	71	73	72	73	73	73	78	81
Manby W 115 kV																
Copeland MTS	130	0	0	51	91	91	92	91	93	93	94	95	96	97	101	106
John TS	314	256	258	207	193	194	194	194	196	195	198	200	202	204	211	224
Strachan TS	169	137	141	142	143	144	143	145	144	145	149	152	156	159	172	182

Table D-4: Toronto Non-Coincident Load Forecast, with the Impacts of Energy-Efficiency Savings

Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW) 2018 (1)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Long-Term Forecast (MW) 2030	2035	2040
North 230 kV																
Agincourt TS	174	112	115	118	120	121	122	123	124	124	124	125	125	126	128	133
Bathurst TS	334	227	237	243	246	247	249	250	251	252	252	255	257	259	275	285
Cavanagh MTS	157	108	109	110	111	112	111	111	112	113	114	113	114	115	123	128
Fairchild TS	346	268	269	270	272	273	275	276	277	278	277	278	279	279	282	287
Finch TS	365	290	295	299	301	302	302	303	304	306	307	309	309	310	314	320
Leslie TS	325	233	240	247	248	251	251	253	255	255	255	256	256	256	270	279
Malvern TS	176	105	106	107	108	108	108	109	110	110	113	115	117	118	126	130
East 230 kV																
Bermondsey TS	348	160	164	165	168	169	170	170	171	173	172	173	172	172	171	178
Ellesmere TS	189	124	126	127	128	129	129	129	130	130	130	130	130	130	129	132
Leaside TS	202	163	169	173	176	176	176	176	178	178	177	178	177	177	177	185
Scarboro TS	340	222	224	226	228	228	229	229	231	233	232	231	232	231	241	247
Sheppard TS	205	178	180	182	185	184	186	187	189	188	188	191	194	196	206	213
Warden TS	182	123	124	125	126	127	128	129	128	128	132	135	137	139	146	151
West 230 kV																
Horner TS (2)	365	141	145	146	147	189	194	195	196	199	203	209	214	219	247	271
Manby TS (2)	226	245	257	260	267	225	225	225	225	225	225	225	225	225	225	225
Rexdale TS	187	136	137	138	137	139	138	140	140	139	139	136	135	133	123	115
Richview TS	460	279	262	266	268	268	270	270	270	272	269	266	261	259	250	240
Leaside 115 kV																
Basin TS	88	65	71	75	75	76	76	77	77	77	79	81	81	82	87	91
Bridgman TS	212	154	153	155	156	155	158	158	158	158	159	159	159	161	171	177
Carlaw TS	73	66	67	67	67	67	67	68	68	69	68	68	68	70	69	69
Cecil TS	215	166	173	178	180	181	183	183	183	184	182	179	176	175	173	173
Charles TS	211	145	150	153	154	154	155	155	156	155	157	159	160	161	167	168
Dufferin TS	170	136	119	122	123	123	123	124	124	126	129	130	133	136	144	148
Duplex TS	128	99	101	99	97	96	93	92	94	95	95	96	96	98	103	108
Esplanade TS	187	163	143	145	146	146	147	147	147	148	147	144	143	139	142	143
Gerrard TS	102	37	47	50	52	52	53	53	53	54	53	53	53	53	53	54
Glengrove TS	88	51	52	52	53	53	53	53	53	52	53	55	56	57	60	62
Main TS	77	60	61	61	62	63	63	62	63	63	65	65	66	66	67	67
Terauley TS	249	175	187	193	188	186	185	188	187	187	185	181	179	177	173	174
Manby E 115 kV																
Fairbank TS	182	171	150	158	162	167	171	173	173	174	175	176	176	175	179	184
Runnymede TS	219	96	63	115	157	156	158	157	160	159	161	161	162	164	170	178
Wiltshire TS	133	56	74	75	74	74	75	75	75	76	76	77	77	77	83	86
Manby W 115 kV																
Copeland MTS	130	0	0	51	91	91	92	91	93	93	94	95	96	97	101	106
John TS	314	264	265	215	200	200	201	201	202	202	205	207	209	211	219	232
Strachan TS	169	139	143	144	145	146	145	147	146	147	151	155	158	161	174	184

(1) Non-coincident station peak, adjusted to extreme weather
(2) Load transferred to the new Horner TS DESN #2 in 2022



GTA North

REGIONAL INFRASTRUCTURE PLAN

October 22, 2020

hydro one

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Prepared by:

Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Alectra Utilities Corporation
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DISCLAIMER

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

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 Study Team.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE RIP STUDY TEAM 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 GTA NORTH REGION.

The participants of the Regional Infrastructure Plan ("RIP") Study Team included members from the following organizations:

- Alectra Utilities
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Newmarket-Tay Power Distribution Ltd.
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the second cycle of GTA North regional planning process, which follows the completion of the GTA North Integrated Regional Resource Plan ("IRRP") in February 2020 and the GTA North Region Needs Assessment ("NA") in March 2018. This RIP provides a consolidated summary of the needs and recommended plans for GTA North Region over the planning horizon (1 – 10 years) based on available information.

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment and IRRP reports for this cycle, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, the following projects have been completed:

- Vaughan #4 MTS (completed in 2017)
- Holland breakers, disconnect switches and special protection scheme (completed in 2017)
- Parkway belt switches at Grainger Jct. (completed in 2018)

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in the Table 1 below, along with their planned in-service date and budgetary estimates for planning purposes.

Table 1. Recommended Plans in GTA North Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate
1	Markham Area: Step-down Transformation Capacity	Build new Markham #5 MTS	2025	$30M
2	Increase Capability of 230kV Circuits P45+P46 (these supply Buttonville TS, Markham #4 MTS, and future Markham #5 MTS)	Reconductor circuits P45/46 from Parkway to Markham #4 MTS, and connect Markham #5 MTS – 2025	2025	$2-3M
3	High voltages on 230kV circuits M80B/M81B	No action required	---	---
4	Northern York Area: Step-down Transformation Capacity	Build new Northern York Station	2027	$35-40M
5	Woodbridge TS: End-of-life of transformer T5	Replace the end-of-life transformer with similar type and size equipment as per current standard	2027	$13
6	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan #5 MTS	2030	$30M

Note: LDC distribution network costs are not included in the above Table.

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 1 while keeping the Study Team apprised of project status;
- All the other long term needs/options identified in Section 6.4 will be further reviewed by the Study Team in the next regional planning cycle.

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1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA NORTH REGION BETWEEN 2020 AND 2030.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) and documents the results of the study with input and consultation with Alectra, Hydro One Distribution, the Independent Electricity System Operator (“IESO”), Newmarket-Tay Power Distribution Ltd. (“NTPDL”) and Toronto Hydro-Electric System Limited (“THESL”) 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, sixteen step-down transformer stations (“TS”), and the York Energy Centre (“YEC”) generating station (“GS”).

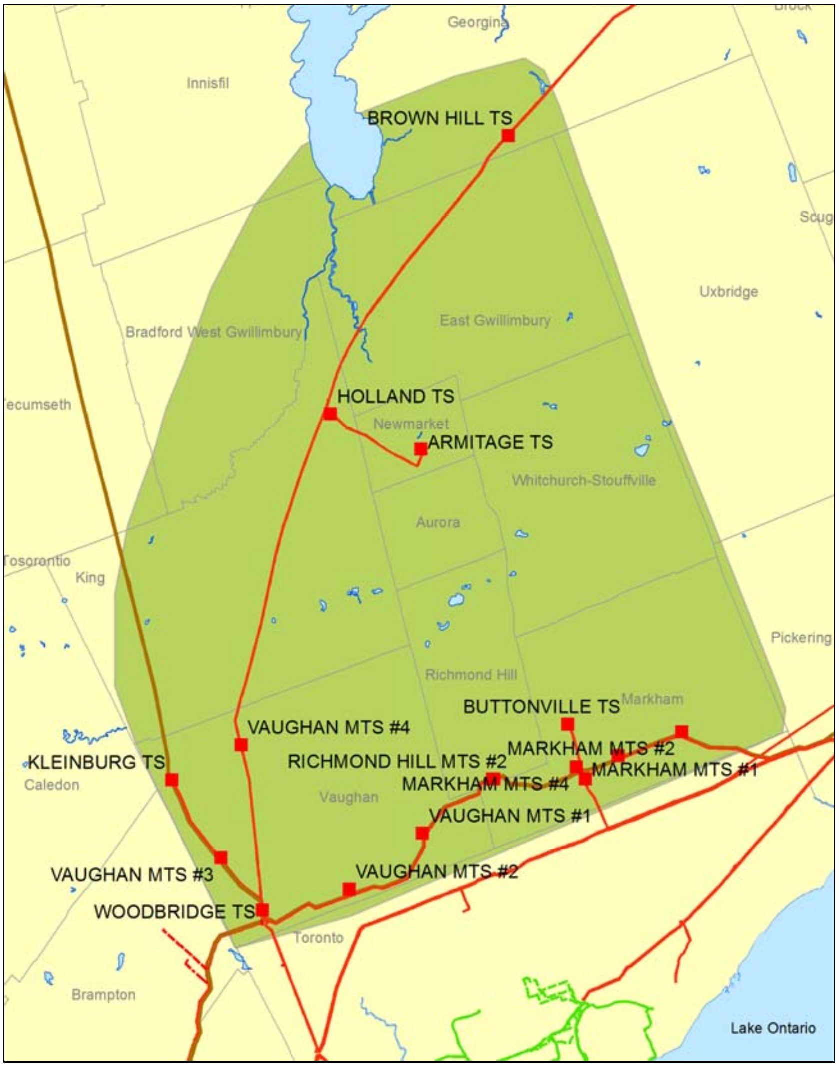


Figure 1-1: GTA North Region Map

1.1 Objectives and Scope

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, as appropriate;
- Provide the status of wires planning projects 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, mid and long-term needs as identified in previous planning phases (Needs Assessment and Integrated Regional Resource Plan).
- Identification of any new needs over the planning horizon and a plan to address them, as appropriate.
- 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 adequacy of the transmission facilities in the region over the study period.
- 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 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 Study Team 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.

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 that 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, Indigenous communities, business sectors and other interested stakeholders in the region.

[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; 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 Hydro One and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in Hydro One's rate filing submissions and as part of LDC rate applications with a planning status letter provided by Hydro One.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or 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;
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers.

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.

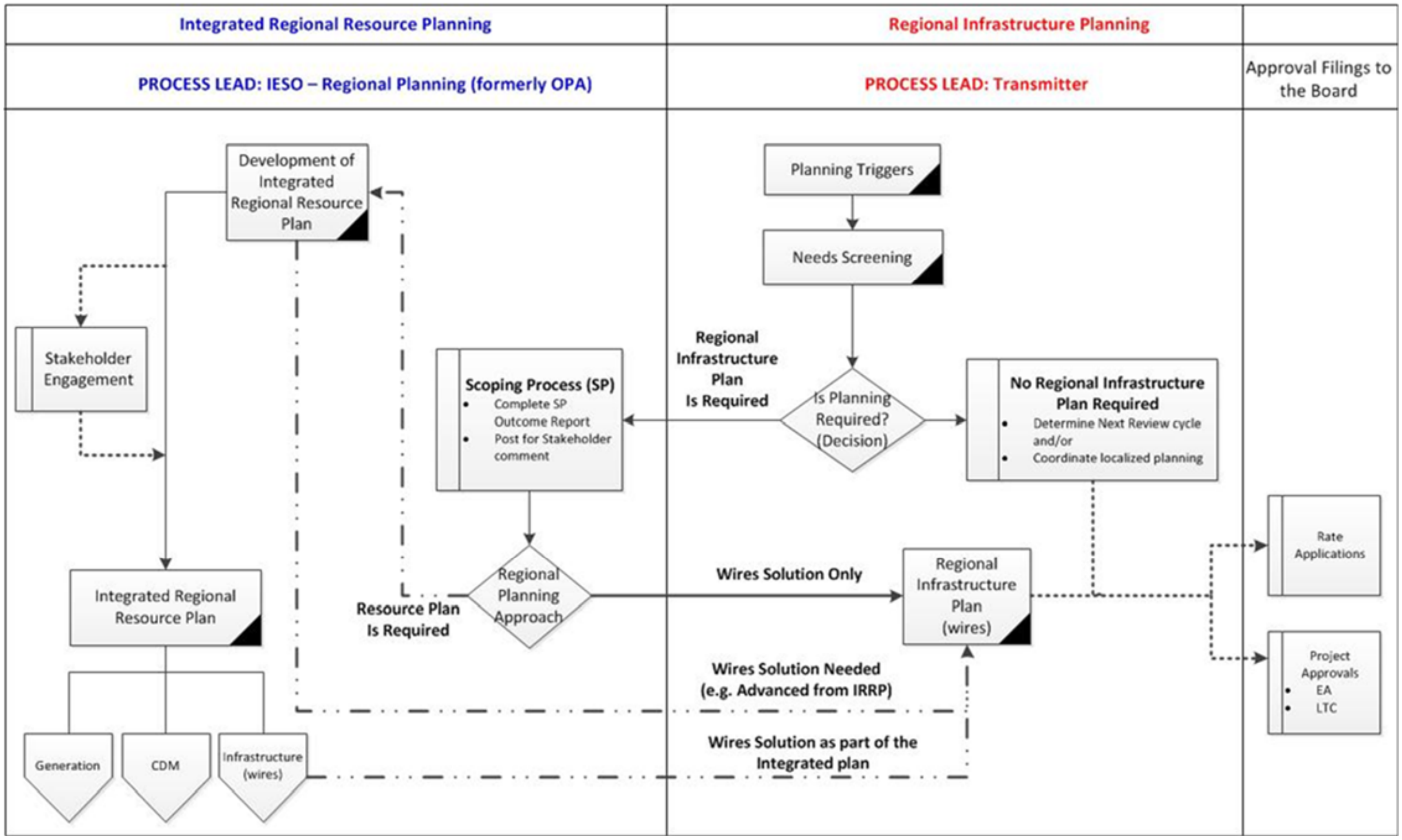


Figure 2-1: Regional Planning Process Flowchart

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 phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team 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. Depending upon the changes to load forecast or other

relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.

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.

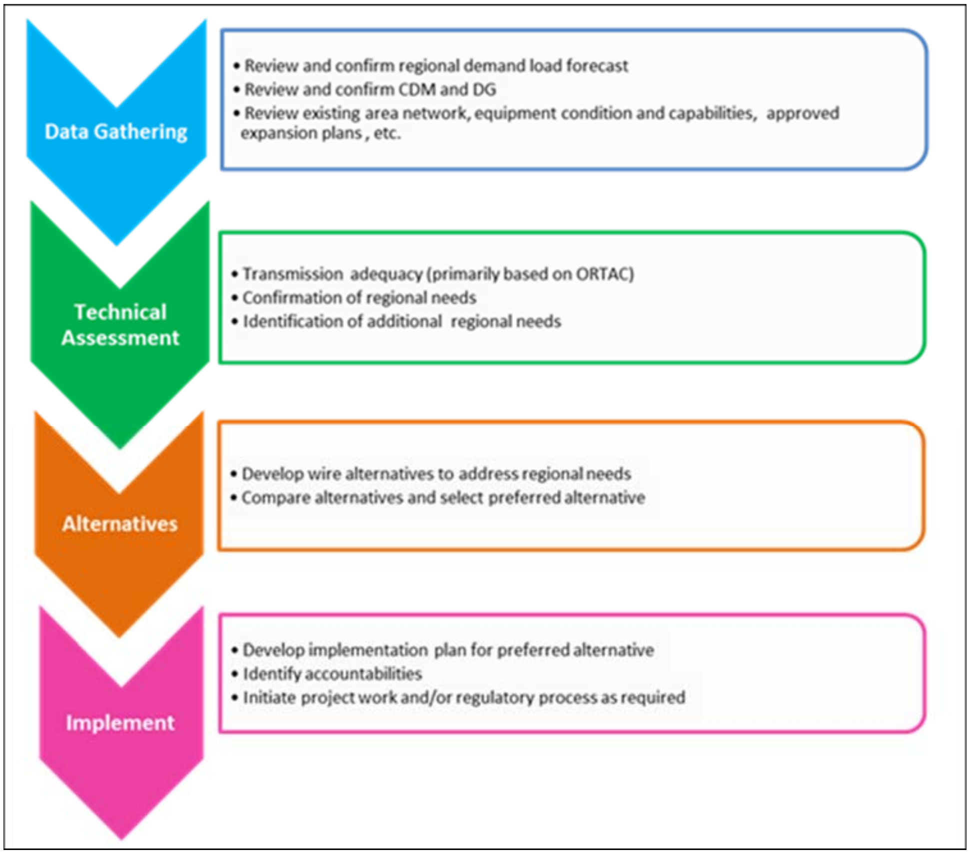


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE GTA NORTH REGION IS COMPRISED OF THE NORTHERN YORK AREA, SOUTHERN YORK AREA AND THE WESTERN AREA. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM SIXTEEN 230 KV STEP-DOWN TRANSFORMER STATIONS. THE 2019 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 2000 MW.

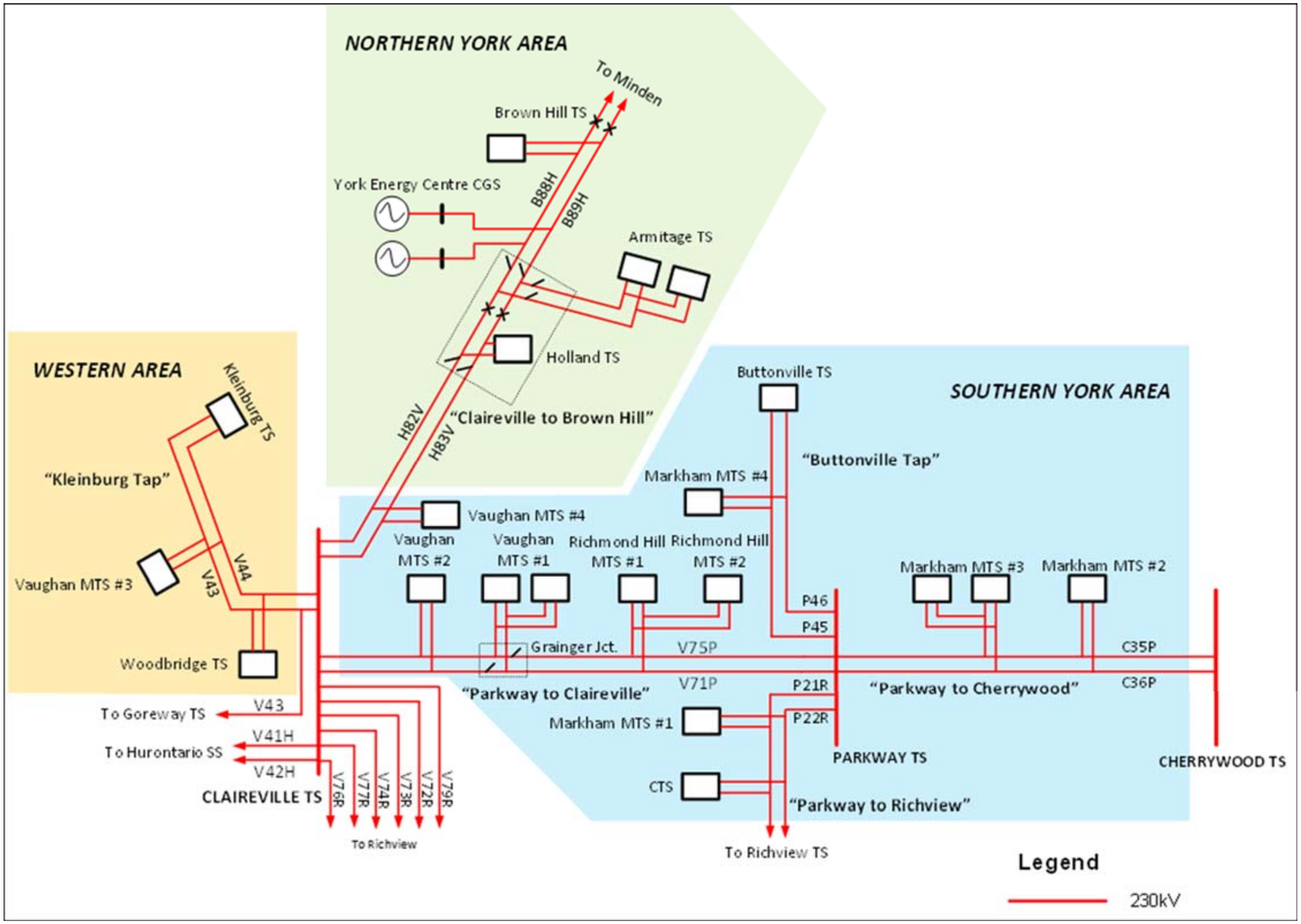
Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B88H/B89H in King Township. Refer to Appendix A, Appendix B and Appendix C for further details.

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 four 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 Alectra.

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 seven 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 Alectra. Please refer to Figure 3-1.

The Western Area comprises the Western portion of the municipality of Vaughan. Electrical supply to the area 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 are Alectra and Hydro One Distribution. Embedded LDCs include Alectra and Toronto Hydro. Please refer to Figure 3-1

Figure 3-1: Single Line Diagram of GTA North Region's Transmission Network



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

OVER THE LAST TEN YEARS, A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY TO THE GTA NORTH REGION.

A summary and description of the major projects completed and/or currently underway over the last ten years is provided below.

- Connect the York Energy Centre generation facility (2012) – to provide a local source of supply for the Northern York Area.
- 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 Northern York area.
- Inline switches on the Parkway belt (V71P/V75P) at Grainger Jct. (2018)

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA North Region is forecast to increase at an average rate of about 2% annually from 2020 to 2030, with average rate of about 2.5% between 2020 and 2025 and about 1.50% between 2025 and 2030.

Figure 5-1 shows the GTA North Region extreme summer weather coincident peak net load forecast ("load forecast"). The 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.

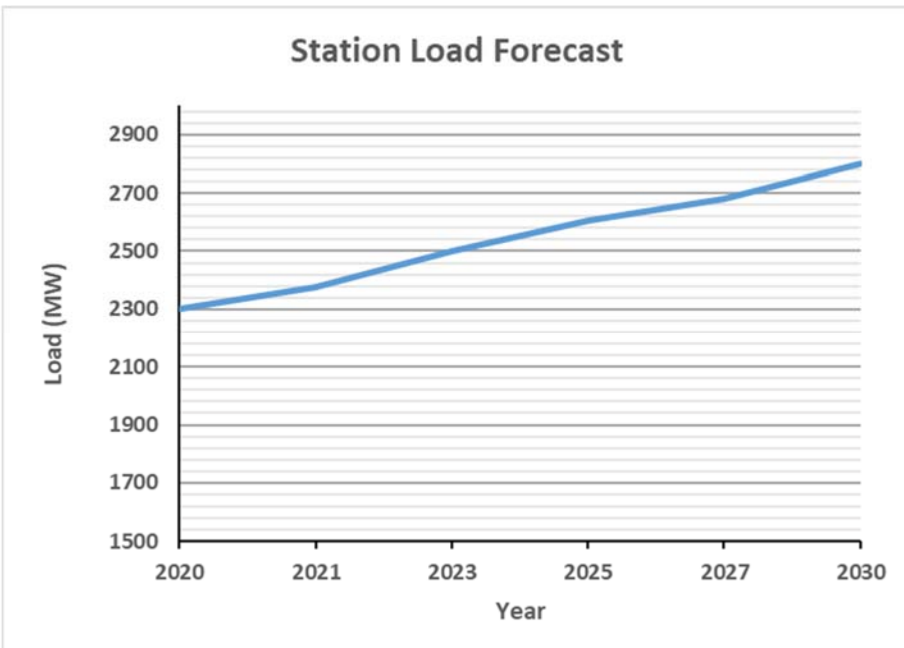


Figure 5-1: GTA North Region Load Forecast

The station coincident peak net loads used in the RIP are consistent with the York Region IRRP. However, as a result of the COVID-19 pandemic, this forecast may require review and updates as the long term impacts on customer demand become better known. The Study Team will be monitoring actual loading in York areas over the coming years and will recommend if updates to need dates or a revised forecast is required. However, based on the available information any change is not expected to materially impact any of the needs identified, but the dates to implement solutions may be affected.

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for this RIP is established from 2020-2030.

- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period 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 for stations, which is consistent with Ontario Resource Transmission Assessment Criteria (ORTAC). Normal planning supply capacity for transformer stations is determined by the summer 10-day Limited Time Rating (LTR).
- Line capacity adequacy is assessed by using peak loads in the area.

6 ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE GTA NORTH REGION OVER THE PLANNING PERIOD (2020-2030).

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 this Regional Infrastructure Plan. The studies are:

- 2018 GTA North Region Needs Assessment Report ("NA")
- 2018 York Region Scoping Assessment Outcome Report ("SA")
- 2020 York Region Integrated Regional Resource Plan and Appendices ("IRRP")

This section provides a review of the adequacy of the transmission lines and stations in the GTA North Region. The adequacy is assessed using the latest regional load forecast provided in Appendix D.

This RIP reviewed the loading on transmission lines and stations in the GTA North Region based on the forecast in Appendix D.

6.1 Adequacy of Northern and Southern York Area 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 Northern and Southern York Areas are comprised of the following 230 kV circuits. Refer to Figure 3-1.

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 Holland TS 230 kV circuits: H82V and H83V.
- Holland TS to Brown Hill TS 230 kV circuits: B88H and B89H.

The RIP review shows that based on current forecast station loadings and bulk transfers, circuits P45 and P46 need to be uprated due to the future connection of Markham MTS #5. The other 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 thirteen step-down transformers stations in the Northern and Southern York Areas as follows in Table 6-1 Step-Down Transformer Stations below:

Table 6-1 Step-Down Transformer Stations

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 #1, #2*
Vaughan MTS #1*	Vaughan MTS #2*	Vaughan MTS #4*
Industrial Customer		

*Stations owned by Alectra

Based on the LTR of these load stations, additional capacity was required in Vaughan and was addressed by Vaughan MTS #4. Based on the forecast in Appendix D, additional capacity is required in Markham as early as 2025, and additional capacity will be needed in Northern York Area and Vaughan as early as 2027 and 2030, respectively. The station loading in each area and the associated station capacity and need dates are summarized in Table 6-2**.**

Table 6-2 Adequacy of the Step-Down Transformation Facilities

Area/Supply	LTR-Capacity (MW)	2020 Summer Forecast (MW)	Need Date
Markham / Richmond Hill transformation Capacity	957	877	2025
Northern York Area (Armitage TS, Holland TS)	485	444	2027
Vaughan Transformation Capacity (Vaughan MTS #1, 2, 4)	612	461	2030
Northern York Area (Brown Hill)	184	94	-

6.2 Adequacy of Western Area Facilities

6.2.1 230 kV Transmission Facilities

The Western Area is comprised of one 230 kV double circuit line V43/V44 between Claireville TS and Kleinburg TS. Refer to Figure 3-1. The line supplies Kleinburg TS, Vaughan MTS #3, and Woodbridge TS. Loading on the V43/V44 line is adequate over the study period.

6.2.2 Step down Transformation Facilities

There are three step-down transmission connected transformation stations in the Western Area as follows:

Table 6-3 Step-Down Transformation Facilities in the Western Area

Kleinburg TS
Woodbridge TS
Vaughan MTS#3*

*Station owned by Alectra

The load forecast in Table 6-4 shows that there is adequate transformation capacity available at these three transformer stations to meet GTA North demand over the study period. Note that these facilities also serve load in the neighbouring GTA West Region. An IRRP is currently underway to determine long term infrastructure needs to serve GTA West, which may affect this region.

Table 6-4 Adequacy of Step-Down Transformation Facilities in the Western Area

	LTR-Capacity (MW)	2020 Summer Forecast (MW)	Need Date
Western Area	509	425	Beyond 2030

6.3 Other Needs Identified During Regional Planning

6.3.1 Load Restoration in the Western Area

There is 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 needs and the Study Team recommendations to address the needs are discussed in more detail in Section 7.4.1.

6.3.2 Load Restoration in the Northern York Area

There is a load restoration need for the loss of the Claireville to Holland double circuit line, H82V/H83V. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The needs and the Study Team recommendations to address the needs are discussed in more detail in Section 7.4.2.

6.3.3 Load Security and Restoration in the Southern York Area

There is a load security need for loss of the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P. Loading on this line exceeds the 600 MW limit as per ORTAC security criteria. The Study Team recommendations to address the needs are discussed in more detail in Section 7.5.

6.3.4 High Voltages on Circuits M80B/ M81B

Post-contingency voltages on M80B/M81B may exceed 250 kV during future high load conditions. High voltages at Beaverton and Lindsay may occur following contingencies that leave these stations radially connected to Minden TS. The Study Team recommendations to address the needs are discussed in more detail in Section 7.3.2.

6.3.5 End of Life of Woodbridge TS- Transformer-T5

Transformer T5 is currently about 47 years old and is approaching End of Life (EOL). This need is further discussed in Section 7.1.

6.4 Longer Term Regional Needs (2030-2040)

The IRRP considers longer-term needs and alternatives that are expected to occur between 2030 and 2040, which are outside the study period of the RIP. Table 6-5 summarizes the long term need for the Claireville to Minden circuits.

Table 6-5: Longer Term Adequacy of Transmission Facilities

Facilities	Area MW Load (1)			MW Load Meeting Capability (Approximate)	Need Date
	2025	2030	2035		
230 kV Claireville to Minden Circuits	727	765	943	850(2)	Beyond 2030

(1) The sum of station's (Vaughan#4 MTS, Holland TS, Armitage TS, Brown Hills TS, Northern York TS, Vaughan#5 MTS excluding Beaverton TS and Lindsay TS) summer peak load adjusted for extreme weather.
(2) 2020 York Region IRRP. Actual capability is dependent on distribution of loads across stations and other system assumptions.

7 REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE GTA NORTH REGION AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

The electrical infrastructure near and mid-term needs in the GTA North Region are summarized below in Table 7-1 and Table 7-2.

Table 7-1: Identified Near and Mid-Term Needs in the GTA North Region

Section	Facilities	Need	Details	Expected Timing
7.1	Woodbridge TS	End of Life (T5)	Transformer T5 is currently about 47 years old and is approaching End of Life (EOL)	2027
7.2.1	Markham# 5 MTS	Step Down Transformation Capacity	Loading at Markham & Richmond Hill area stations exceeded.	2025
7.2.2	Northern York TS		Loading at Armitage TS and Holland TS exceeded.t.	2027
7.2.3	Vaughan#5 MTS		Loading at Vaughan area stations exceeded.	2030
7.3.1	P45/P46 (Parkway TS to Markham #4 Jct.)	Supply Capability	Thermal limits are exceeded on a 1.1km section of the circuits between Parkway MTS and Markham #4 MTS due to the future connection of Markham MTS # 5.	2029
7.3.2	Claireville TS to Minden TS Corridor	Voltage Rise	Voltage rise on stations along M80B/M81B following loss of B88H/B89H	2025
7.4.1	Kleinburg radial pocket (V43/44)	Load Restoration	Restoration of loads supplied by V43/V44 does not meet the 30 minute load restoration criteria	Existing
7.4.2	H82V/H83V – Holland, Vaughan #4 and #5		Restoration of loads supplied by H82V/H83V does not meet the 30 minute load restoration requirement	Existing
7.5	Parkway TS to Claireville TS Circuits V71P/V75P	Load Security	Load security needs have previously been identified for the V71/75P Parkway corridor.	Existing

Table 7-2: Identified Long-Term Needs in GTA North Region

Section	Facilities	Need	Details	Timing
7.3.3	Claireville TS x Minden TS Corridor	Supply Capability	Thermal ratings & Voltage drop limits exceeded	Beyond 2030

7.1 Woodbridge TS: T5 End-of-Life Transformers

7.1.1 Description

Woodbridge TS comprises one DESN unit, T3/T5 (75/125 MVA), with two secondary winding voltages at 44 kV and 27.6 kV, each with a summer 10-Day LTR of 80 MW, supplying both Alectra and THESL. The station's 2019 actual peak load was 149 MW. Transformer T5 is currently about 47 years old and has been identified to be at its EOL.

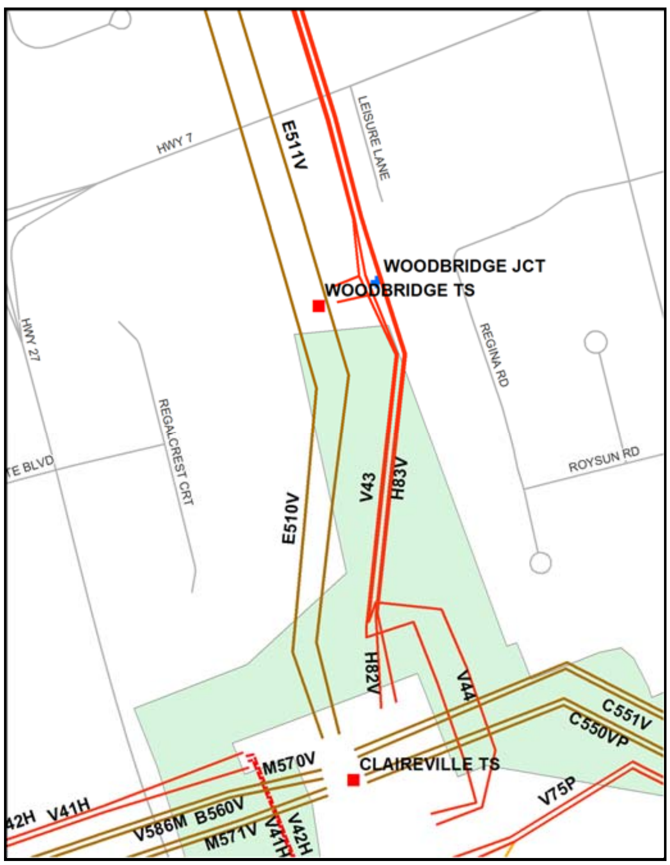


Figure 7-1: Woodbridge TS

7.1.2 Alternatives and Recommendation

The following alternatives were considered to address the Woodbridge T5 end-of-life need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
2. **Alternative 2 - Replace with similar type and size equipment as per current standard:** Under this alternative the existing transformer T5 at Woodbridge TS is replaced with a new 75/125 MVA 230/44-27.6 kV transformer. This alternative would address the need and would maintain reliable supply to the customers in the area.
3. **Alternative 3 – Re-configure Woodbridge TS as two separate 44 kV and 27.6 kV DESNs:** Hydro One has not considered this option further since there is currently no need for the additional transformation capacity, and there are limitations on the high voltage supply circuits. The cost of rebuilding the station would also be high.

The Study Team recommends that Hydro One proceed with Alternative 2 and coordinate the replacement plan with affected LDCs. The expected completion date for this work is 2027.

7.2 Station Supply Capacity Needs and Plans

Needs assessment and IRRP have identified three new station capacity needs in the medium term, one in the Markham –Richmond Hill region, designated as Markham MTS#5, the second in the Vaughan Area, designated as Vaughan MTS#5 and third in the Northern York Area, location and designation to be determined. The timelines associated with these needs require all the stakeholders to monitor station loadings and ascertain pace of the growth including energy efficiency (EE) and other Distributed Energy Resource (DER) impacts. Below are the options for the above needs to finalize the suitable location and explore the long-term options.

7.2.1 Markham MTS #5 Transformer Station

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 north Markham area. Based on the current load forecast, the additional transformation capacity is required by the year 2025.

7.2.1.1 Alternatives and Recommendation

Three alternative locations for connecting the new Markham MTS #5 have been considered by the Study Team and shown in Figure 7-2.

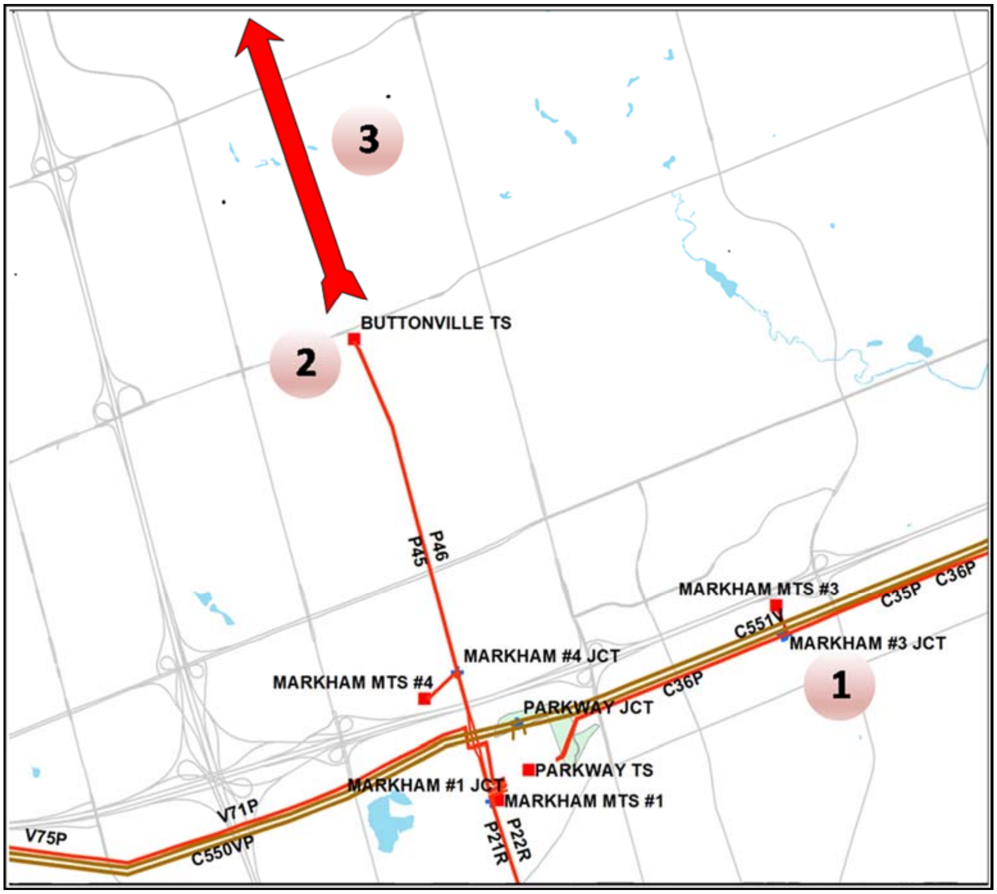


Figure 7-2: Location options for Markham #5 MTS

1- **Alternative 1- Building the new station along the Parkway belt and connecting to the C35P/ C36P circuits:** The C35P/C36P transmission circuits are capable of supplying the full capacity of the station, but the alternative has been ruled out because the physical location of the station would be too far from the area of anticipated growth resulting in high distribution costs. There is also a risk that the capacity of this station will become stranded if it becomes technically infeasible to supply load concentrated along Markham's northern border

2- **Alternative 2- Building the station at the existing Buttonville TS and connecting to the P45/P46 circuits:** This alternative is closer to the area of anticipated load growth than alternative 1, and lesser distribution infrastructure is required as compared to Alternative 1. A 1.1 km section between Parkway TS and the Markham MTS#4 Jct would need to be uprated.

3- **Alternative 3 - Building the station in north Markham and extending circuits P45/P46 from Buttonville TS to connect the new station:** This location is nearest to the area of anticipated load growth. However, this option requires rebuilding approximately 6 km of a single circuit 115 kV transmission line as a 230 kV double circuit transmission line. Most of the 6 km corridor is adjacent to residential areas and the previous plan to upgrade this infrastructure resulted in community opposition. It is likely that some portion of the transmission line would need to be undergrounded. A new station property would also need to be acquired.

Alternative 1 was not considered further due to the high distribution costs. Of the remaining two alternatives, the Study Team recommends Alternative 2 - building the new station at Buttonville TS. While the distribution costs are higher under this option, the higher costs of extending the transmission line north from Buttonville for Alternative 3, made these two alternatives comparable for the overhead option only. Alternative 2 was selected as the preferred option in response to community preferences.

Alectra will be building the station and Hydro One will be building the line tap connection from the P45/P46. The current planned in-service date for the new station is 2025.

7.2.2 Northern York Area Transformer Station

Additional step down transformation capacity is needed for the areas supplied by Armitage TS and Holland TS. There is transfer capability between these stations, so their combined LTR of 485 MW is used to determine the need. Based on the load forecast, it is expected that additional step down transformation capacity will be needed by 2027. Refer to Table 7-3 below.

Table 7-3: Northern York Area Peak Loading

Final Peak Demand Forecast, extreme weather by Station (MW)							
Station	**LTR (MW)**	**2020**	**2021**	**2023**	**2025**	**2027**	**2030**
Armitage	317	302	307	312	312	312	312
Holland	168	142	145	154	166	168	168
Northern York Area	153	0	0	0	0	12	32
Grand Total		**444**	**452**	**466**	**478**	**492**	**512**

7.2.2.1 Alternatives and Recommendation

It is anticipated that the new station will be supplied by circuits B88H/B89H which are in the vicinity of the forecasted load growth. Further discussions between Hydro One and the LDCs are recommended to determine the final location and connection point in order to meet an in-service date of 2027.

7.2.3 Vaughan Area Transformer Station

The Vaughan area station load in the Southern York Area is expected to increase from 461 MW in 2020 to 614 MW by 2030 exceeding the combined area stations capacity of 612 MW. Additional transformation capacity will therefore be needed in Vaughan by 2030. Alectra has sufficient space at Vaughan #4 MTS to accommodate another station there. However, there isn’t sufficient transmission capacity available on the Claireville to Minden corridor to fully supply a second new transformation station, given that a new station in Northern York is anticipated by 2027. Therefore a plan to increase transmission supply capability to the area will be required before a plan for the new transformation station in Vaughan can be committed. This is discussed further in Section 7.3.3.

7.2.3.1 Alternatives and Recommendation

The location chosen for and the land allocated to Vaughan MTS#4 is well suited to cater the load growth and provides enough land to build another step-down station. Building a new station at the same site would have an incremental cost of approximately $30 million.

7.3 System Capacity Needs and Plans

The Study Team has identified the following system capacity needs

7.3.1 Transmission Line uprate- P45/P46

The connection of the new Markham MTS#5 to the Parkway TS x Buttonville TS circuit P45/P46 circuits (see Figure 7-3 below) will increase the loading on these circuits. The forecast loading along with the long term emergency circuit rating is given in Table 7-4.

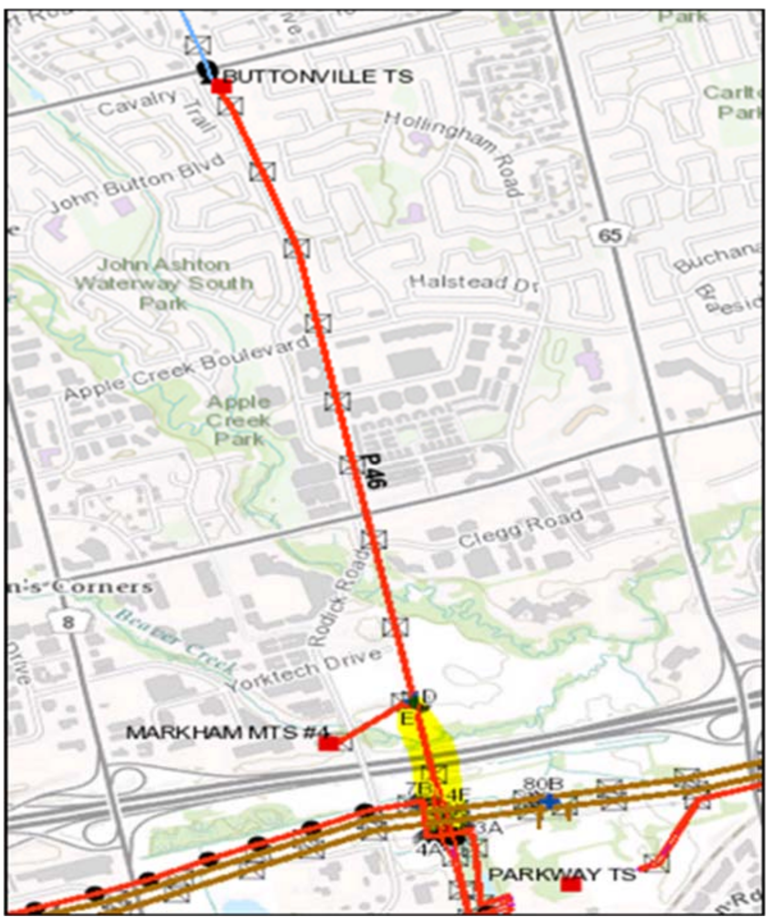


Figure 7-3: Buttonville Tap P45/P46 Limiting Section

The transmission capacity is thermally limited by an approximately 1.1 km long section between Parkway TS and Markham #4 Jct. Loading is expected to exceed the rating by 2029. This section will need to be uprated by 2029 to fully supply Markham MTS#5.

Table 7-4: Loading on Buttonville Tap Circuits

Final Peak Demand Forecast, extreme weather by Station (MW)							
	Circuit Rating (MW)	**2020**	**2021**	**2023**	**2025**	**2027**	**2030**
Buttonville TS		148	148	147	156	156	154
Markham MTS #4		99	128	153	153	153	153
Markham MTS #5		0	0	0	26	77	153
Grand Total	**420**	**247**	**276**	**300**	**335**	**386**	**460**

7.3.1.1 Alternatives and Recommendation

Two alternatives were considered to provide adequate capacity on the P45/P46 circuits.

1- **Alternative 1 - Increase thermal capability of existing line.** It is expected that the thermally limiting section of this line can be increased by changing the conductor to be capable of supplying the forecasted load on these circuits. A high level estimate for this work is $2-3 million.

2- **Alternative 2 – Reduce loading on the P45/P46 circuits by transferring Markham MTS#4 to the Cherrywood TS x Parkway TS C35P/C36P circuits:** This alternative frees up capacity on the P45/P46 circuits to supply MTS#5. It requires building a new 1.5 km long 230kV double circuit line from Markham MTS#4 Jct to the C35P/C36P. This alternative was ruled out due to higher cost and greater disruption to the local community.

The Study Team recommends Alternative 1 as the technically preferred and most cost-effective alternative to increase the supply capability on P45/P46. It is also prudent to consider uprating these circuits before 2029 to reduce the amount of load at risk during construction outages. Completing this upgrade in time for the Markham MTS#5 in service date will also allow for the LDC to make full use of this facility's capacity to manage distribution operations including restoration, optimizing feeder loading, and accommodating maintenance.

7.3.2 High Voltages on M80B/M81B

Post-contingency voltages on M80B/M81B may exceed 250 kV during future high load conditions. High voltages at Beaverton and Lindsay may occur following contingencies that leave these stations radially connected to Minden TS. These high voltages are observed when low voltage capacitor banks at Beaverton and Lindsay are dispatched under heavy load. In the long term, it is expected that infrastructure solutions required to meet anticipated post 2030 capacity needs will also address this need, though advancing this type of solution to address voltage needs is not recommended due to much lower cost and lower impact alternatives. The IRRP recommends identifying and implementing the solution not later than 2025 to mitigate the voltage rise issue.

7.3.2.1 Alternatives and Recommendations

Two alternatives were considered for the mitigation of the high voltages:

1- **Alternative 1 – Switch LV caps manually at Beaverton and Lindsay:** The high voltage equipment is capable of withstanding voltages up to 5% above nominal voltage (i.e. 262.5 kV) for up to 30 minutes. This capability provides sufficient time for operators to manually adjust the system. Under this alternative the operator will remotely switch out capacitor banks at Beaverton and Lindsay to mitigate high voltages when required.

2- **Alternative 2 - Expanding the York Region Special Protection Scheme (SPS):** The problem of overvoltage can be mitigated by modifying the York Region SPS to automatically remove capacitor banks at Lindsey TS and/or Beaverton TS under high load conditions following specific contingencies.

The Study Team agreed that Alternative 1 will meet the need as the system can withstand the expected voltages and manual action is adequate.

7.3.3 Long Term Need - Supply Capability of the Clairvelle TS to Minden TS Corridor

The Claireville-Minden corridor is comprised of three sections which are defined by inline breakers at Holland TS and Brown Hill TS:

- Section 1 - Claireville TS x Holland TS - H82V/H83V, supplying Holland TS and Vaughan MTS #4.
- Section 2 - Holland TS x Brown Hill TS - B88H/B89H, supplying Armitage TS and Brown Hill TS and connects the York Energy Centre generation. The station service supply to York Energy Centre is normally supplied by a distribution feeder from Holland TS.
- Section 3 - Brown Hill TS x Minden TS - M80B/M81B, supplying Beaverton TS and Lindsay TS. These two stations are not part of the GTA North Region.

The York Region SPS increases the load supply capability of the Claireville –Minden Circuits. The SPS enables controlled load rejection at Vaughan#4 MTS, Holland TS, Armitage TS, Brown Hill TS following certain contingencies. The scheme can also reject generation at YEC, as required. The York Region SPS ensures that the transmission system does not get overloaded following certain contingences, consistent with ORTAC.

In the long term, the supply capability of the corridor is limited by both thermal and voltage capability of the transmission system. These needs arise after 2030 and consistent with the IRRP, the wires needs and alternatives identified are summarized below.

Thermal Limitations

The southern (Claireville TS x Brown Hill TS) section of the corridor supplies Vaughan MTS#4, Holland TS, Armitage TS and Brown Hill TS. Future proposed stations - Northern York area and Vaughan MTS#5 – will also be connected to this corridor. The forecast loading on the corridor is given in Table 7-5. Loading on the corridor will exceed its thermal limits of approximately 850 MW by about 2035.

Table 7-5: Loading on Claireville TS to Minden TS Circuits

Final Peak Demand Forecast, extreme weather by Station (MW)								
Station	**Loading Limit (MW)**	**2020**	**2021**	**2023**	**2025**	**2027**	**2030**	**2035**
Armitage TS		302	307	312	312	312	312	312
Brown Hill TS		94	95	95	96	97	98	100
Holland TS		142	145	154	166	168	168	168
Northern York Area TS		0	0	0	0	12	32	62
Vaughan MTS #4		54	63	108	153	153	153	153
Vaughan MTS#5		0	0	0	0	0	2	147
Grand Total	**850**	**592**	**610**	**670**	**727**	**743**	**765**	**942**

Voltage Limitations

Post-contingency voltage drop will exceed ORTAC limits on the Claireville to Minden corridor after 2030. The limiting contingency is H82V/H83V which drops Holland TS, Vaughan #4 MTS and the future Vaughan #5 MTS by configuration. In addition, up to 150 MW of load rejection is permitted by ORTAC. YEC station service is normally supplied from Holland TS, so the generation is lost coincident with the contingency.

7.3.3.1 Alternatives and Recommendations

The IRRP includes two alternatives to deal with long term needs:

- New Line between Kleinberg TS and Kirby Jct.
- New Line between Buttonville TS and Armitage TS.

The Study Team agrees that the preferred plan will be developed during the next planning cycle as the need date is beyond 2030.

7.4 Load Restoration

Load restoration describes the electricity system's ability to restore power to a customer affected by a transmission outage within specified time frames. Both transmission and distribution (transfer) measures are considered when evaluating restoration capability. The load restoration criteria is defined in ORTAC and summarized in Figure 7-4.

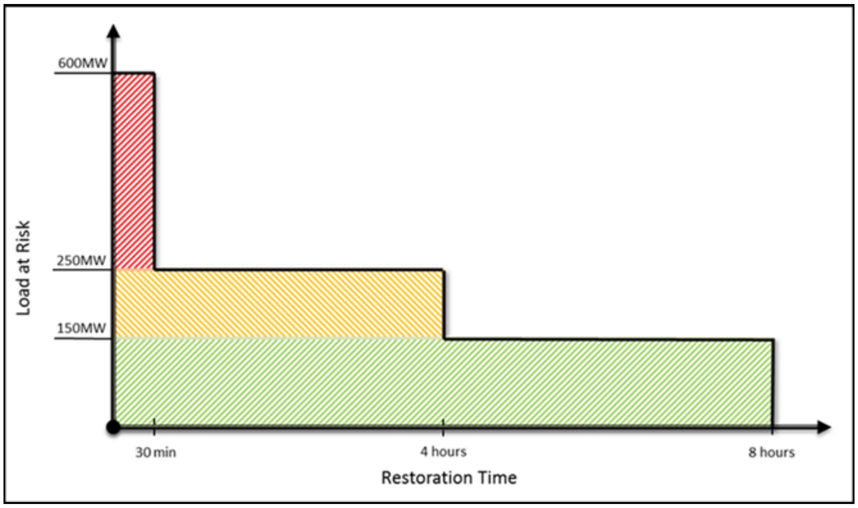


Figure 7-4: Load Restoration Criteria as per ORTAC

There is less risk of violation of ORTAC load restoration criteria especially within the municipalities of Vaughan, Markham, and Richmond Hill due to the availability of transfer capability between adjacent service territories. The Northern York and Western areas are prone to restoration risks which include the service areas served by Holland TS, Armitage TS, and Brown Hill TS and also in the Kleinburg TS area.

7.4.1 Load Restoration on Kleinburg Radial Tap (V43/44)

Load restoration was assessed for 230 kV radial double circuit line V43/V44 supplying Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS that primarily supply rural and urban communities in Vaughan and Caledon and, to a lesser degree, Brampton, Mississauga and Toronto. In case of a double circuit outage of the V43/V44 line, not all loads in excess of 250 MW can be restored within 30 minutes, as per the ORTAC restoration criteria. The V43/V44 line is approximately 12 km long with good accessibility by maintenance crews and Hydro One expects all load to be restored within 4 hours with at least one circuit back into service.

Table 7-6: Load Restoration on Kleinburg Radial Tap

V43/V44-Restoration	Limit	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Interrupted Load		426	436	444	449	453	450	453	454	455	456	475
Remaining after 30 minutes	250	347	357	366	370	355	352	356	357	358	359	376
Remaining after 4 hours	150	0	0	0	0	0	0	0	0	0	0	0

7.4.1.1 Alternatives and Recommendations

The Study Team agreed that no further action is required at this time. However the need will be reviewed in the next iteration of the regional planning cycle. The historical reliability of these circuits has been good with no coincident outages of the two circuits; there have only been two direct outages[2] to circuit V43 since 2008 and no direct outages to circuit V44 since 2009. While there are no short term plans to address this need, the Kleinburg to Kirby option to address supply capacity needs in the long term would also improve the load restoration capability for these circuits. Based on the long term forecast the supply capacity needs will arise between 2030 and 2035. This alternative is discussed in further detail in Section 7.3.3. Until such time as a preferred long term solution is identified for the Claireville to Minden corridor, there is no need to pursue other alternatives.

7.4.2 Load Restoration on Claireville TS to Holland TS circuits (H82V/H83V)

Load restoration was assessed for 230 kV circuits H82V/H83V supplying Vaughan #4 MTS and Holland TS. In case of a double circuit outage of H82V/H83V, not all loads exceeding 250 MW can be restored within 30 minutes per the ORTAC criteria. However, Hydro One expects all loads to be restored within 4 hours with one circuit back in service. Refer to Table 7-7.

Table 7-7: Load Restoration on Claireville TS to Holland TS circuit (H82V/H83V)

H82V/H83V-Restoration	Limit	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load loss by configuration		196	208	225	262	300	319	321	321	321	320	323
Load loss by SPS		90	96	101	101	101	101	106	113	120	126	132
Total Interrupted Load		286	304	326	363	401	420	427	434	441	447	456
Remaining after 30 minutes	250	250	268	290	327	347	366	373	380	387	393	402
Remaining after 4 hours	150	0	0	0	0	0	0	0	0	0	0	0

[2] A direct outage is reported whenever a major component is in the outage state due to a condition or equipment failure directly associated with it.

7.4.2.1 Alternatives and Recommendations

Following the loss of H82V/H83V, the normal station service supply to YEC generation will also be lost. Holland TS cannot be restored from B88H/B89H until YEC generation is restored. Transferring YEC to an alternate source of station service supply cannot be completed within 30 minutes. Therefore the Study Team recommends that the IESO identify and consider the possibility of a new station service supply arrangement at YEC to enable faster restoration of load on H82V/H83V, consistent with the load restoration criteria.

7.5 Improve Load Security on the Parkway to Claireville Line

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. The load security criteria in ORTAC 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.

7.5.1 Alternatives and Recommendations

The previous RIP recommended the installation of inline switches on the V71P/V75P circuits at the Vaughan MTS #1 junction to improve load restoration capability following loss of both V71P/V75P circuits. The switches do not reduce the amount of load that is interrupted, however the project enables Hydro One to quickly isolate the problem and allow the resupply of load to occur expeditiously.

Hydro One completed this project in 2018 at a cost of $5.1 million.

The Study Team accepts that the load security criteria is not met, but agrees that no further action is required at this time since the switches permit quick restoration of the load.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA NORTH REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 8-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1: Recommended Plans in GTA North Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate
1	Markham Area: Step-down Transformation Capacity	Build new Markham #5 MTS	2025	$30M
2	Increase Capability of 230kV Circuits P45+P46 (these supply Buttonville TS, Markham #4 MTS, and future Markham #5 MTS)	Reconductor circuits P45/46 from Parkway to Markham #4 MTS, and connect Markham #5 MTS – 2025	2025	$2-3M
3	High voltages on 230kV circuits M80B/M81B	No action required	---	---
4	Northern York Area: Step-down Transformation Capacity	Build new Northern York Station	2027	$35-40M
5	Woodbridge TS: End-of-life of transformer T5	Replace the end-of-life transformer with similar type and size equipment as per current standard	2027	$13M
6	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan #5 MTS	2030	$30M

Note: LDC distribution network costs are not included in the above Table.

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 8-1 while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

9 REFERENCES

[1] GTA North Regional Infrastructure Plan – February 2016

[2] GTA North Needs Assessment – March 2018

[3] York Region Scoping Assessment Outcome Report - 2018

[4] Integrated Regional Resource Plan (IRRP) - February, 2020

[5] Integrated Regional Resource Plan (IRRP) - Appendices - March, 2020

[6] IESO Ontario Resource Transmission Assessment Criteria (ORTAC)

10 APPENDIX A. STATIONS IN THE GTA NORTH REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Kleinburg TS T1/T2 27.6	230/27.6	V44/V43
Kleinburg TS T1/T2 44	230/44	V44/V43
Vaughan MTS #3 T1/T2	230/27.6	V44/V43
Woodbridge TS T3/T5 27.6	230/27.6	V44/V43
Woodbridge TS T3/T5 44	230/44	V44/V43
Armitage TS T1/T2	230/44	B88H/B89H
Armitage TS T3/T4	230/44	B88H/B89H
Brown Hill TS T1/T2	230/44	B88H/B89H
Holland TS T1/T2, T3/T4	230/44	H82V/H83V
Buttonville TS T3/T4	230/27.6	P45/P46
Markham MTS #1 T1/T2	230/27.6	P21R/P22R
Markham MTS #2 T1/T2	230/27.6	C35P/C36P
Markham MTS #3 T1/T2	230/27.6	C35P/C36P
Markham MTS #3 T3/T4	230/27.6	C35P/C36P
Markham MTS #4 T1/T2	230/27.6	P45/P46
CTS	230/13.8	P21R/P22R
Richmond Hill MTS #1 T1/T2	230/27.6	V71P/V75P
Richmond Hill MTS #2 T3/T4	230/27.6	V71P/V75P
Vaughan MTS #1 T1/T2	230/27.6	V71P/V75P
Vaughan MTS #1 T3/T4	230/27.6	V71P/V75P
Vaughan MTS #2 T1/T2	230/27.6	V71P/V75P
Vaughan MTS #4 T1/T2	230/27.6	H82V/H83V

11 APPENDIX B. TRANSMISSION LINES IN THE GTA NORTH REGION

Location	Circuit Designations	Voltage (kV)
Claireville TS to Holland TS	H82V/H83V	230
Holland TS to Brown Hill TS	B88H / B89H	230
Claireville TS to Kleinburg TS	V43/V44	230
Claireville TS to Parkway TS	V71P/V75P	230
Parkway TS to Markham MTS #1 and CTS	P21R/P22R	230
Parkway TS to Buttonville TS	P45/P46	230
Parkway TS to Cherrywood TS	C35P/C36P	230

12 APPENDIX C. DISTRIBUTORS IN THE GTA NORTH REGION

Distributor Name	Station Name	Connection Type
Alectra Utilities Corporation	Armitage TS	Tx/Dx
	Buttonville TS	Tx
	Holland TS	Dx
	Kleinburg TS	Tx
	Markham MTS #1	Tx
	Markham MTS #2	Tx
	Markham MTS #3	Tx
	Markham MTS #4	Tx
	Richmond Hill MTS #1	Tx
	Richmond Hill MTS #2	Tx
	Vaughan MTS #1	Tx
	Vaughan MTS #2	Tx
	Vaughan MTS #3	Tx
	Vaughan MTS #4	Tx
	Woodbridge TS	Tx/Dx
Distributor Name	**Station Name**	**Connection Type**
Newmarket-Tay Power Distribution Ltd	Armitage TS	Tx/Dx
	Holland TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Hydro One Distribution	Armitage TS	Tx
	Brown Hill TS	Tx
	Holland TS	Tx
	Kleinburg TS	Tx
	Woodbridge TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Toronto Hydro Electric System Limited	Woodbridge TS	Dx

13 APPENDIX D. GTA NORTH REGION LOAD FORECAST

Station	Summer LTR (MW)	2020	2021	2023	2025	2027	2030	2035
Armitage	317	302	307	312	312	312	312	312
Brown Hill	184	94	95	95	96	97	98	100
Northern York Area	153	0	0	0	0	12	32	62
B88H/B89H Total		396	402	407	408	421	442	474
Holland	168	142	145	154	166	168	168	168
H82V/H83V Total	168	142	145	154	166	168	168	168
Northern York Area Sub-Total		**538**	**547**	**561**	**574**	**589**	**610**	**642**
Markham #2	101	101	101	101	101	101	101	101
Markham #3	202	202	202	202	202	202	202	202
C35P/C36P Total		303	303	303	303	303	303	303
Markham #1	81	81	81	81	81	81	81	81
P21R/P22R Total		81	81	81	81	81	81	81
Buttonville	166	148	148	147	156	156	156	154
Markham #4	153	99	128	153	153	153	153	153
Markham #5	153	0	0	0	26	77	153	153
P45/P46 Total		247	276	300	335	386	462	460
Richmond Hill	254	246	246	245	250	254	254	254
Vaughan #1	306	265	275	300	306	306	306	306
Vaughan #2	153	142	151	153	153	153	153	153
V71P/V75P Total		653	672	698	709	713	713	713
Vaughan #4	153	54	63	108	153	153	153	153
Vaughan #5	153	0	0	0	0	0	2	147
H82V/H83V Total		54	63	108	153	153	155	300
Southern York Area Sub-Total		**1338**	**1395**	**1490**	**1581**	**1636**	**1714**	**1857**

Station	**Summer LTR (MW)**	**2020**	**2021**	**2023**	**2025**	**2027**	**2030**	**2035**
Kleinburg	196	144	145	146	147	148	169	170
Vaughan #3	153	132	141	153	153	153	153	153
Woodbridge	160	149	149	150	150	153	154	153
V43/V44 Total		425	435	449	450	454	476	476
Western Area Sub-Total		**425**	**435**	**449**	**450**	**454**	**476**	**476**
GTA North Region Total		**2301**	**2377**	**2500**	**2605**	**2679**	**2800**	**2975**

Toronto Region:

Integrated Regional Resource Plan

August 9, 2019

ieso
Connecting Today.
Powering Tomorrow.

Toronto Region
Integrated Regional Resource Plan

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator (IESO) pursuant to the terms of its Ontario Energy Board license, EI-2013-0066.

The IESO prepared the IRRP on behalf of the Toronto Regional Planning Working Group (Working Group), which included the following members:

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

The Working Group developed a plan that considers the potential for long term electricity demand growth and varying supply conditions in the Toronto region, and maintains the flexibility to accommodate changes to key conditions over time.

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List of Acronyms

Acronym/ Alternative	Description
CHP	Combined Heat and Power
DER	Distributed Energy Resource
DESN	Dual Element Spot Network
DR	Demand Response
EA	Environmental Assessment
FIT	Feed-in Tariff
GTA	Greater Toronto Area
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTE	Long-term Emergency Rating
LTR	Limited Time Rating
MVA	Mega Volt Ampere
MW	Megawatt
NWA	Non-wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portlands Energy Centre
PV	Photo-voltaic (Solar)
RAS	Remedial Action Scheme
RIP	Regional Infrastructure Plan
SS	Switching Station

Acronym/ Alternative	Description
STE	Short-term Emergency Rating
Toronto Hydro	Toronto Hydro-Electric System Limited
TPSS	Traction Power Sub-station
TS	Transmission Station or Transformer Station
Working Group	Technical Working Group for Toronto Region IRRP

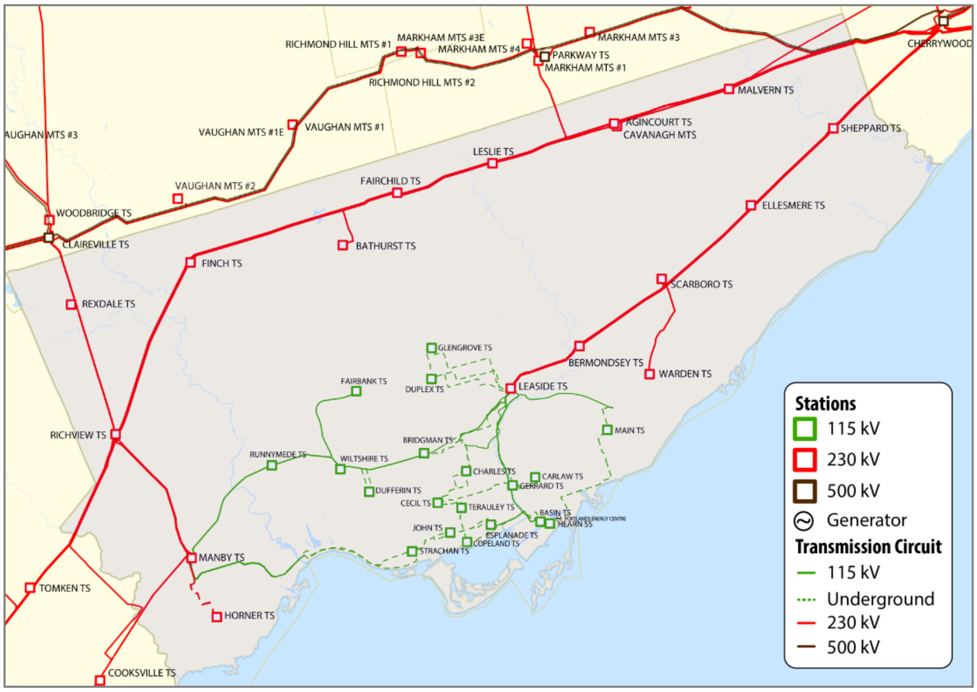
1. Introduction

This Integrated Regional Resource Plan (IRRP) addresses the regional electricity needs for the City of Toronto (Toronto region) between 2019 and 2040.[1] This report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Working Group comprising the IESO, Toronto Hydro-Electric System Limited (Toronto Hydro), and Hydro One Networks Inc. (Hydro One).

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is carried out through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for 21 electricity planning regions across Ontario, at least once every five years. The Toronto region, shown in Figure 1-1, corresponds with the municipal boundaries of the City of Toronto. Other electricity planning regions adjacent to the Toronto region include Greater Toronto Area (GTA) West, GTA East, and GTA North.

[1] The planning horizon year is 2040: the different time frames within the plan period include the near term (up to five years out); medium term (six to 10 years out); and long term (11 to 20 years out).

Figure 1-1: Location of the Toronto Region



This IRRP reaffirms the needs and plans previously identified in the Metro Toronto Regional Infrastructure Plan (RIP) published in January 2016, and the Needs Assessment report completed in 2017. It identifies new capacity and reliability needs of the electric transmission system, and recommends approaches to ensure that Toronto's electricity needs can be met over the planning horizon. Specifically, the plan recommends approaches for addressing a number of end of life asset replacement needs and potential longer-term capacity needs to accommodate growth and city development.

For needs that may emerge in the longer term (11 to 20 years out), the plan maintains flexibility for new solutions. As the long term needs highlighted by the technical studies are subject to uncertainty related to future electricity demand and technological change, this IRRP does not recommend specific investments to address them at this time.

The plan identifies some near term actions to monitor demand growth, explore possible long term solutions, engage with the community, and gather information to lay the groundwork for determining options for future analysis. The near term actions recommended are intended to be completed before the next regional planning cycle, scheduled for 2024 or sooner, depending on demand growth or other factors that could trigger early initiation of the next planning cycle.

This report is organized as follows:

- A summary of the recommended plan for the Toronto region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for regional electricity planning in the Toronto region and the study scope are discussed in Section 4;
- The demand outlook scenarios, and energy efficiency and distributed energy resource (DER) assumptions, are described in Section 5;
- Electricity needs in the Toronto region are presented in Section 6;
- Options and recommendations for addressing the needs are described in Section 7;
- A summary of engagement activities to date, and moving forward, is provided in Section 8; and
- A conclusion is provided in Section 9.

2. Summary of the Recommended Plan

The recommendations in this IRRP are focused on replacement of assets at their end of life, and preparing to address local and regional capacity needs emerging in the longer term.

The successful implementation of the recommended actions summarized below is expected to address the region's electricity needs until at least the late 2020s.

2.1 The Plan

This plan re-affirms the needs and plans identified in the previous regional planning cycle that concluded in January 2016, and recommends the actions described below to address the region's transmission needs until at least the late 2020s or early 2030s.

The recommendations set forth in this plan are summarized as follows:

Replace end of life overhead line sections H1L/H3L/H6LC/H8LC and L9C/L12C

The Working Group recommends that Hydro One proceed with planning for the like for like replacement of these overhead line sections.

Replace end of life transformers at Main TS

The Working Group recommends that Hydro One proceed with planning to replace the existing transformers with 60/100 MVA transformers.

Continue planning for replacement of C5E/C7E underground transmission cables

The Working Group recommends that Hydro One continue planning to replace the existing cables.

Continue planning to determine end of life approaches for Manby TS, John TS, and Bermondsey TS

Manby TS and John TS: The Working Group recommends that detailed planning for end of life of these assets continue, starting with the RIP.[2]

Bermondsey TS: The Working Group recommends that the plan to replace the two end of life transformers at Bermondsey TS be completed within the scope of the RIP.

Gather information to inform future capacity planning for Basin TS

Since there is currently insufficient information to characterize the needs at Basin TS and inform specific recommendations in this IRRP, the Working Group proposes that any recommendation on potential solutions be deferred until the next cycle of regional planning, or earlier, as required.

Specifically, the Working Group recommends that Toronto Hydro coordinate continued planning activities related to defining the nature, scope and timing of the future capacity need at Basin TS, and assessment of possible wires and non-wires alternative (NWA) solutions to address the need.

Proceed with reinforcement of the Richview TS to Manby TS 230 kV corridor

The Working Group recommends that Hydro One proceed with the reinforcement of the Richview TS to Manby TS 230 kV corridor and begin community engagement, as well as initiate the environmental assessment (EA).

Keep options available to address long term regional supply capacity needs

For the longer-term regional capacity needs, including the Leaside TS and Manby TS autotransformers, Manby TS to Riverside Junction lines, and Bayview Junction to Balfour Junction circuit section, the Working Group recommends that the IESO coordinate continued planning work and engagement with stakeholders and the community to:

- Define and communicate, as soon as practicable, the longer-term capacity needs

[2] The RIP is described in Section 3.1.

- Identify opportunities for a range of cost-effective solutions, including NWAs such as DERs and energy efficiency
- Identify potential wires solutions and avoidable costs should these needs be deferred through NWAs

The information and insights developed through these activities will be used to inform the next regional planning cycle.

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, planning to meet an area's electricity needs at a regional level is completed through the regional planning process, which assesses regional needs over the near, medium, and long term, and develops a plan to ensure cost-effective, reliable electricity supply. A regional plan considers the existing transmission electricity infrastructure in an area, local supply resources, forecast growth and area reliability; evaluates options for addressing needs; and recommends actions to be undertaken.

The current regional planning process was formalized by the OEB in 2013, and is conducted for each of the province's 21 electricity planning regions by the IESO, transmitters and local distribution companies (LDCs) on a five-year cycle.

The process consists of four main components:
1) A needs assessment, led by the transmitter, which completes an initial screening of a region's electricity needs;
2) A scoping assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3) An IRRP, led by the IESO, which identifies recommendations to meet needs requiring coordinated planning; and/or
4) An RIP led by the transmitter, which provides further details on recommended wires solutions.

More information on the regional planning process and the IESO's approach to regional planning can be found in Appendix A: Overview of the Regional Planning Process.

3.2 Toronto Region Working Group and IRRP Development

Development of the Toronto region IRRP was initiated in late 2017 with the release of a needs assessment prepared by Hydro One on behalf of the Toronto Regional Planning Working Group comprised of the IESO, Toronto Hydro, Alectra Utilities, Veridian Connections (now elexicon energy) and Hydro One Distribution. The report identified transmission needs that may require coordinated planning in the Toronto region, with needs limited to the electrical system within the municipal boundaries of the City of Toronto.

Subsequent to the Needs Assessment Report, the IESO prepared a Scoping Assessment Outcome Report, which recommended that an IRRP be undertaken to address a number of needs, owing to the potential for coordinated solutions. No sub-regions were identified for the purpose of carrying out this IRRP. Given the location of the needs identified, the IRRP Working Group was determined at the scoping assessment stage to include the IESO, Toronto Hydro and Hydro One.[3]

In 2018, the Working Group began gathering data, conducting assessments to identify near term to long term needs in the area, and recommending actions to address Toronto's electricity transmission needs.

[3] Distribution system planning does not fall within the scope of a regional planning study, though regional plans may inform distribution system plans. Distribution system plans are undertaken by local distribution companies and reviewed and approved by the OEB under a separate process.

4. Background and Study Scope

This is the second cycle of regional planning for the Toronto region. When the OEB formalized the regional planning process in 2013, planning was already underway in the Central Toronto area, a sub-region of Toronto that includes the downtown core. As such, Central Toronto became one of the Group 1 planning regions, and the first to participate in the formalized regional planning process.

The first cycle of regional planning for the Toronto region was completed in January 2016 with the publication of Hydro One's RIP for the Central Toronto area. Subsequent to the completion of an IRRP for Central Toronto (in April 2015), the IESO published an update to the IRRP that accounted for plans to convert commuter heavy rail in the GTA from diesel to electric power.

The second cycle of regional planning for Toronto was initiated by Hydro One in mid-2017. Following publication of a needs assessment in October 2017, a scoping assessment, released in February 2018, identified a number of needs requiring further regional coordination, and recommended that an IRRP for the Toronto region be initiated. No sub-regions within Toronto were recommended for this IRRP.

Building on past regional studies and taking into account updates to activities, including investments in electricity infrastructure and Toronto Hydro's long term outlook for electricity, this IRRP focuses on:

- Identifying recommendations for replacing assets that are reaching end of life
- Supporting and enabling growth and planned urban development
- Maintaining a high level of reliability performance

To set the context for this IRRP, the scope of the planning study and the area's existing electricity system are described in Section 4.1.

4.1 Study Scope

This IRRP, prepared by the IESO on behalf of the Working Group, recommends options to meet the regional electricity needs of the Toronto region. Guided by the principle of maintaining an adequate level of reliability performance as per the *Ontario Resource and Transmission Assessment Criteria* (ORTAC), this study recognizes the importance of electricity service to the functioning of a large urban centre. The Toronto Region Scoping Assessment Outcome Report established the objectives, scope, roles and responsibilities, and timelines for this IRRP. The plan considers the long term outlook for electricity peak demand, energy efficiency, and transmission system capability and transmission asset condition. Options for addressing needs also considered relevant transmission and distribution system projects and capabilities, community plans, and distributed energy resources (DERs).

The transmission facilities that were included in the scope of this study are presented in Table 4-1 (stations) and Table 4-2 (circuits).

Table 4-1: Summary of Station Facilities (230 kV and 115 kV)

Leaside 115 kV	Manby 115 kV	East 230 kV	North 230 kV	West 230 kV
Basin TS	Copeland TS	Bermondsey TS	Agincourt TS	Horner TS
Bridgman TS	Fairbanks TS	Ellesmere TS	Bathurst TS	Manby TS[3]
Carlaw TS	John TS	Leaside TS[4]	Cavanagh TS	Rexdale TS
Cecil TS	Runnymede TS	Scarboro TS	Fairchild TS	Richview TS
Charles TS	Strachan TS	Sheppard TS	Finch TS	
Dufferin TS	Wiltshire TS	Warden TS	Leslie TS	
Duplex TS			Malvern TS	
Esplanade TS				
Gerrard TS				
Glengrove TS				
Main TS				
Terauley TS				
Hearn SS[5]				

[4] Includes the step-down transformers and 230/115 kV autotransformers
[5] Hearn Switching Station (SS)

Table 4-2: Summary of Transmission Circuits (230 kV and 115 kV)

230 kV	115 kV	
C10A	C5E	K11W
C14L	C7E	K12W
C15L	D11J	K13J
C16L	D12J	K14J
C17L	D6Y	K1W
C20R	H10DE	K3W
C2L	H11L	K6J
C3L	H12P	L12C
C4R	H13P	L13W
R1K	H14P	L14W
R2K	H1L	L15
R13K	H2	L16D
R15K	H2JK	L18W
R24C	H3L	L2Y
K21C	H6LC	L4C
K23C	H7L	L5D
	H8LC	L9C
	H9DE	

Transmission supply is provided to Toronto Hydro from 35 step-down transformer stations that are supplied by transmission voltages operating at either 230 kV or 115 kV. Toronto Hydro delivers electricity from these transmission supply points to its customers through its own electricity distribution system. Eighteen 230 kV step-down transformer stations supply the eastern, western and northern parts of Toronto (18 of these stations supply 27.6 kV voltage and two also supply 13.8 kV electricity to the distribution system); and 17 115 kV step-down stations supply the Central Toronto area (15 at 13.8 kV and two at 27.6 kV on the distribution side). The supply to these central 115 kV stations comes from two 230 kV/115 kV autotransformer stations (Leaside TS and Manby TS). The Toronto region also includes the Portlands Energy Centre (PEC) connected to the 115 kV transmission system (within the Leaside TS sector). The PEC 550 MW combined-cycle power plant plays an important role locally, and for the provincial electricity system, in providing reliable capacity to meet electricity demand, as well as reactive power and voltage support. Hearn SS provides 115 kV switching facilities for the Leaside area and also connects PEC to this system.

The Toronto region and its transmission supply infrastructure are shown in Figure 4-1 (map) and Figure 4-2 (single line diagram). Transmission circuit nomenclature used throughout this report (e.g., H1L, H3L, etc.) can be referenced using the single line diagram.

Figure 4-1: The Regional Transmission System Supplying Toronto

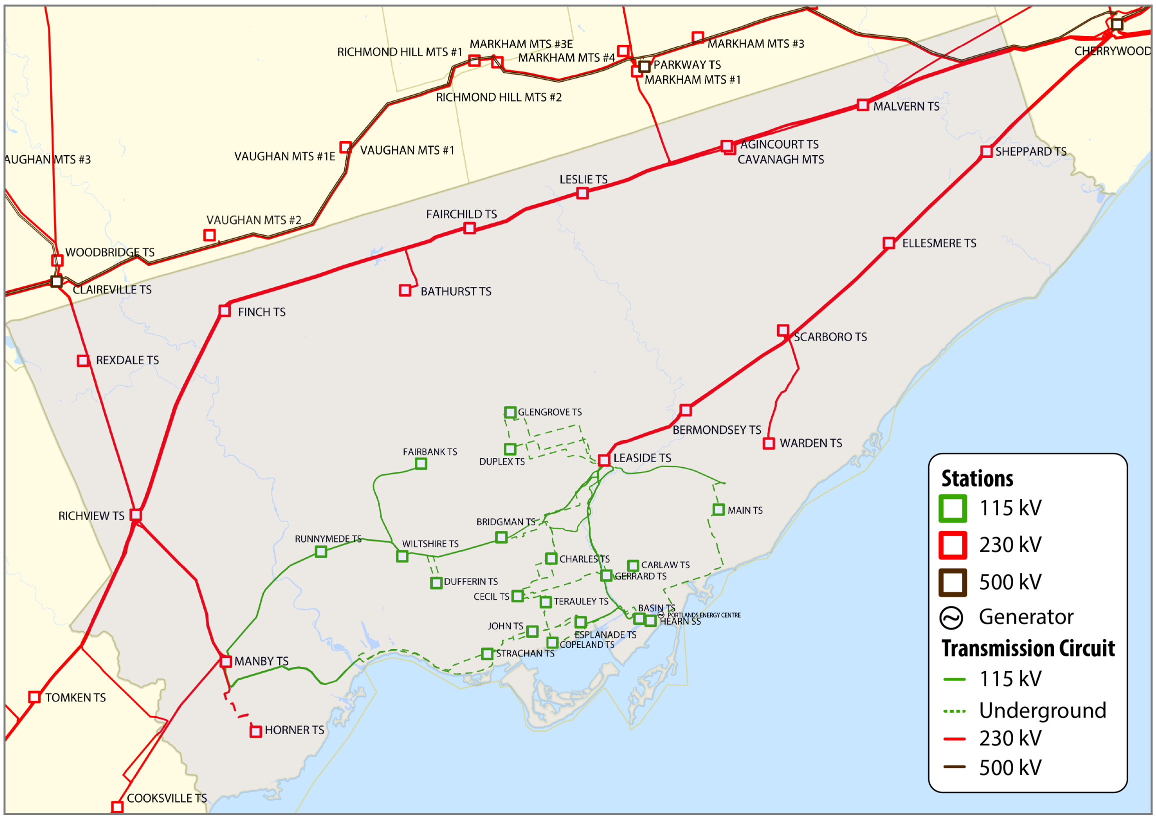
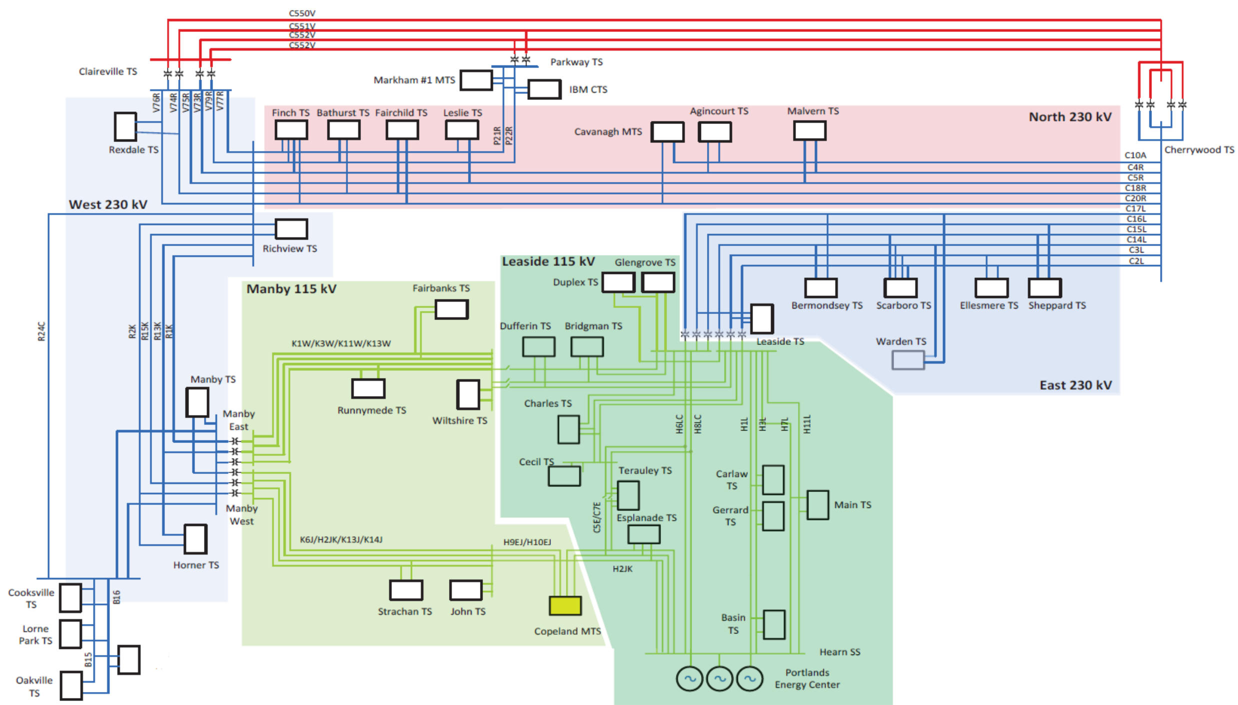


Figure 4-2: The Toronto Region Electrical System (Single-Line Diagram)



Completing the Toronto IRRP involved:

- Preparing a long term electricity peak demand outlook (forecast);
- Examining the load meeting capability and reliability of the transmission system supplying the region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities (such as reactive power devices);
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid as described in Section 7 of ORTAC;
- Confirming identified end of life asset replacement needs and timing with Hydro One;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as NWAs;
- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating alternatives to address near and long term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5. Peak Demand Outlook

The electricity system needs that are in scope for regional planning are driven by the limits of the transmission infrastructure supplying an area, which is sized to meet peak demand requirements (rather than energy demand requirements).[6] Peak demand requirements appearing at the station level are aggregated to understand the limits of the regional transmission system supplying the area as well as individual stations. Regional planning typically focuses on the regional-coincident peak demand to assess regional transmission needs, and individual station peaks to assess local transformer station capacity needs (the demand outlook is broken down spatially by transformer station, or each dual element spot network (DESN) that makes up a station[7]).

Individual stations within the Toronto study area typically experience peak loading at around the same time (e.g., weekdays, generally between 4 and 6 p.m. in summer, after consecutive hot days). There is also a high degree of coincidence between when individual stations peak and when the region peaks.

5.1 Demand Outlook Methodology

Toronto Hydro, in consultation with the Working Group, prepared a peak demand outlook at the transformer station bus level per IESO requirements for performing this study.

The outlook was developed in two parts:

1. Development of the Gross Peak Demand Outlook (Gross Outlook)
2. Development of the Net Peak Demand Outlook (Net Outlook)

The Gross Outlook recognizes the strengths of different forecasting methodologies for different time periods. The first 10 years is based upon the linear regression of past peak demands combined with known load additions and load redistributions. The period beyond 10 years is

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[6] Peak demand of the electric system is typically measured in terms of megawatts (MW) capacity; energy is the capacity needed over a period of time, for example, one megawatt used over one hour is a megawatt-hour (MWh).

[7] A DESN refers to a standard station layout, where two supply transformers are configured in parallel to supply one or two medium-voltage switchgear (for example, 13.8 kV or 27.6 kV), which the distributor uses to supply load customers. This parallel dual supply ensures reliability can be maintained in the event of an outage or planned maintenance. A single local transformer station can have one, two, or more individual DESNs.

based upon the growth rates predicted from an econometric model that takes population, employment, and long term weather into account.

The Gross Outlook is a "business-as-usual" peak demand forecast under extreme weather. The Net Outlook considers load drivers that are over and above those considered in the "business as usual" Gross Outlook. These "new and emerging" load drivers were:

- electric vehicles
- electrification of mass transit
- fuel switching from natural gas to electric for space heating and water heating
- energy storage

The result was a station-by-station outlook of annual peak demand through to 2041. More details may be found in Appendix B: Peak Demand Outlook for Toronto 2017-2041.

5.2 The Outlook for Energy Efficiency

The outlook for future peak demand savings is based on mandated efficiencies from Ontario building codes and equipment standards, which set minimum energy efficiency levels through codes and regulations. To estimate the impact of efficiency codes and standards in the Toronto region, the peak demand savings for the residential, commercial and industrial sectors were estimated at the provincial level, compared with Toronto's station-based peak demand forecast, and expressed as a percentage of peak demand offset on an annual basis. This estimation took into account the breakdown of the peak demand at the station of residential, commercial, and industrial sector demand. Estimated peak demand savings, in MW, were calculated based on the percentage demand offset and the Demand Outlook described in Section 5.1.

These savings were subtracted from the demand outlook, and this forecast with efficiency codes and standards was used to test the sensitivity of the need dates as identified by the Net Outlook described in Section 5.1.

Table 5-1 shows the total peak demand savings attributable to efficiency codes and standards for the Toronto area, for selected years within the planning horizon.

Table 5-1: Estimated Peak Demand Savings from Codes and Standards

Year	2020	2025	2030	2040
Estimated savings (MW)	86	159	242	311

Source: IESO

A more detailed methodology on the outlook for energy efficiency, including assumptions and a breakdown by station and year, is provided in Appendix C: Energy Efficiency Forecast.

5.3 Outlook for Distributed Energy Resources

In addition to energy efficiency, DERs in the Toronto region have previously offset, and are expected to continue to offset peak demand. Previous procurements, including the Feed-in Tariff (FIT) Program, have helped to increase the amount of renewable DERs in Toronto. Other competitive generation procurements have also resulted in additional DER types, such as combined heat and power (CHP) projects.[8] The DERs under contract with the IESO include a mix of solar photovoltaics (PV), CHP, and wind resources.

Further to these, competitive procurement pilots run by the IESO for energy storage resources have resulted in some energy storage projects in the region, and are supporting efforts to better understand the barriers related to integration of energy storage into Ontario's electricity market.

The peak demand impact of DERs that were connected to the system at the time the demand outlook was produced would be implicitly accounted for in the outlook. Given the difficulty of predicting where future DERs may be located, and uncertainty around future DER uptake, no further assumptions have been made regarding future DER growth. Instead of assuming future DER growth implicitly as a load modifier in the demand outlook, the potential of future DERs will be considered as potential solution options.

While the FIT Program and other competitive procurements for small-scale generation, including CHP, have ended, the IESO has been engaged in developing market-based mechanisms to enable a variety of electricity resources to compete in the electricity market. In addition, the IESO is engaged in several activities to enable DERs as alternatives to wires-based solutions. This includes working with other sector participants to identify and overcome

[8] Since the IRRP forecast was developed, contracts for some generators included in the 2017 list have been terminated.

barriers to DER participation and implementation, as many of the issues extend beyond the IESO's mandate.

The IESO's work and other electricity sector initiatives related to DER barriers are expected to inform ongoing discussions on possible future DER options in Toronto, as per the recommendations made in this IRRP.

6. Power System Needs

Based on the demand outlook, system capability, identified end of life asset replacement needs, and application of provincial planning criteria, the Working Group identified electricity needs in the Toronto region in the near, medium, and long term.

6.1 Needs Assessment Methodology

ORTAC,[9] the provincial criteria for assessing the reliability of the transmission system, was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of both the bulk transmission system and local or regional reliability requirements. See Appendix D: Toronto IRRP Study Results, and Appendix E: Station Capacity Assessment, for more details.

In applying ORTAC, three broad categories of needs can be identified:

- **Local Capacity** describes the electricity transmission system's ability to deliver power to LDCs through regional step-down transformer stations. This is determined by the Limited Time Rating (LTR) of the station, which is typically determined by the rating of its smallest transformer(s), under the assumption that the largest transformer is out of service.[10]
- **Regional Capacity** is the electricity transmission system's ability to provide continuous supply to LDCs in a local area, which is limited by the load meeting capability (LMC) of the transmission facilities in the area. The LMC is determined by evaluating the maximum peak demand that can be supplied to an area accounting for limitations of the transmission element(s) (e.g., a transmission line, group of lines or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC. LMC studies are conducted using power system simulations analysis (see Appendix D, Toronto IRRP Study Results, for more details). Regional capacity needs are identified when the peak demand for the area exceeds the LMC of regional transmission facilities.
- **Load Security and Restoration** is the electricity transmission system's ability to minimize the impact of potential supply interruptions in the event of a credible contingency (e.g., a transmission outage considered for planning purposes), such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security

[9] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

[10] A station's rating is determined by its most limiting component(s), which may not always be the transformer(s).

describes the maximum limit of load interruption that is permissible in the event of a transmission outage considered for planning. These limits reflect past planning practices in Ontario. Load restoration describes the electricity transmission system's ability to restore power to a transmission customer (e.g., LDC) affected by a transmission outage within specified time frames. Specific requirements can be found in ORTAC, Section 7, Load Security and Restoration Criteria.

The plan also identifies requirements related to the end of life of transmission assets. End-of-life asset replacement needs are identified by the transmitter based on a variety of factors, such as asset age, condition, expected service life, and risk associated with the failure of the asset. Replacement needs identified in the near and early medium term time frame typically reflect the assessed condition of the assets, while replacement needs identified in the longer term are often based on the equipment's expected service life. As such, any recommendations for medium term needs or those farther out reflect a potential for the need date to change based on priority and/or updates to asset condition.

6.2 Power System Needs

Through the planning studies for the Toronto IRRP, the Working Group identified four main categories of needs: (1) end of life asset replacement, (2) local transformer station capacity, (3) regional supply capacity, and (4) load security and restoration. In addition, pursuant to ORTAC provisions, maintaining a higher level of reliability performance (i.e., above the minimum standards) was also considered which identified some 'discretionary' reliability needs.[11] The specific needs under each of these categories are explained in the sections that follow.

6.2.1 End-of-life Asset Replacement Needs

Hydro One identified a number of end of life transmission asset replacement needs for the Toronto region in the needs assessment phase of this regional planning cycle, with several needs arising in the near to medium term.

[11] 'Discretionary' reliability needs are transmission system issues that are flagged through the application of a uniform set of planning criteria for all of Toronto's transmission system (e.g., by applying 'bulk power system' criteria to 'local area' facilities). This identifies issues that are discretionary in the sense that the reliability performance of the system complies with the criteria; but may represent opportunities to improve reliability to an area if cost-effective opportunities are available.

Since end of life needs are based on the best available asset condition information at a given point, the timing of asset replacement can change, as more recent asset condition results become available. If asset deterioration occurs faster than predicted, need dates may need to be advanced. As a result, the scope and timing of some of these needs have been updated since the needs and scoping assessments were completed.

6.2.1.1 Near-term Asset End-of-life Replacement Needs

Three near term asset end of life replacement needs were addressed within the scope of this plan (Table 6-1). These needs are described further in this Section. The options considered for addressing these needs are described in Section 7.1.1.

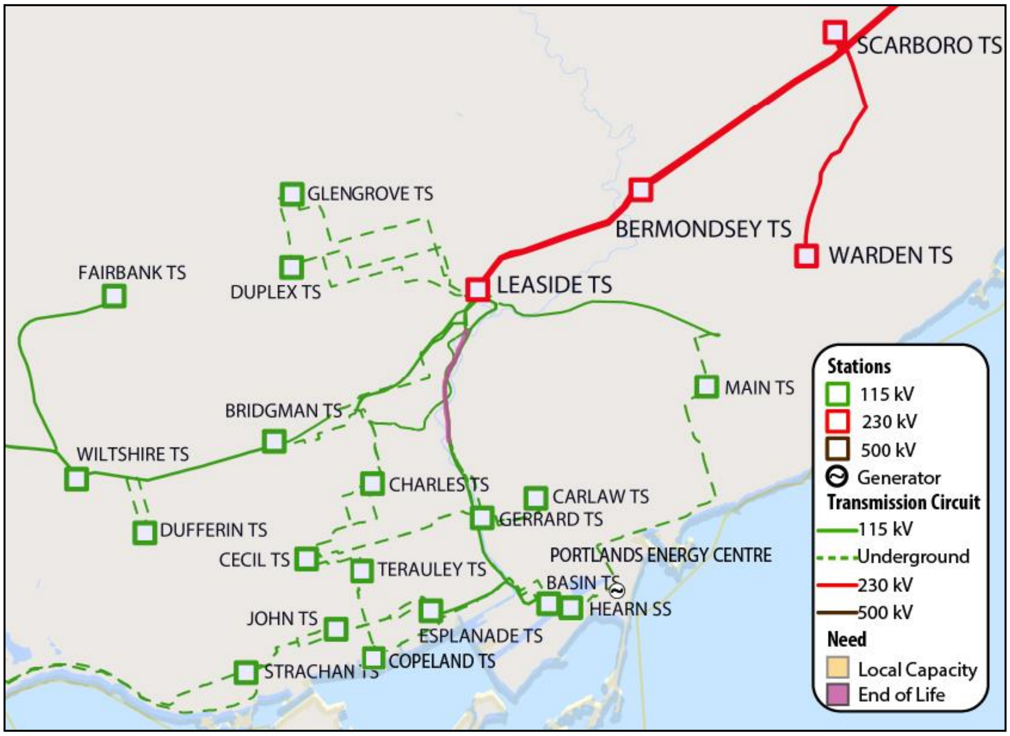
Table 6-1: Toronto Region End-of-life Asset Replacement Needs (Near term)

Facilities	Need	Expected Timing
Leaside Junction to Bloor Street 115 kV overhead transmission lines (H1L/H3L/H6LC/H8LC)	End of life of the approximate 2-km overhead line sections	2022-2023
Leaside TS to Balfour Junction 115 kV overhead transmission lines (L9C/L12C)	End of life of the approximate 3.6-km overhead line sections	2023-2024
Main TS	End of life of transformers T3 and T4, 115 kV line disconnect switches, and 115 kV current voltage transformers	2021-2022

<u>Leaside to Bloor Street 115 kV overhead transmission lines (H1L/H3L/H6LC/H8LC)</u>

The 115 kV overhead transmission lines H1L, H3L, H6LC, and H8LC provide supply to the eastern part of central Toronto from Leaside TS. The end of life part of the line is a 2-km section that runs from Leaside Junction to Bloor Street Junction in the Don Valley, and is on a common tower with four circuits (Figure 6-1). Hydro One has determined the conductors are reaching the end of their useful life, and will need to be replaced by 2022-2023 to maintain safety and reliability.

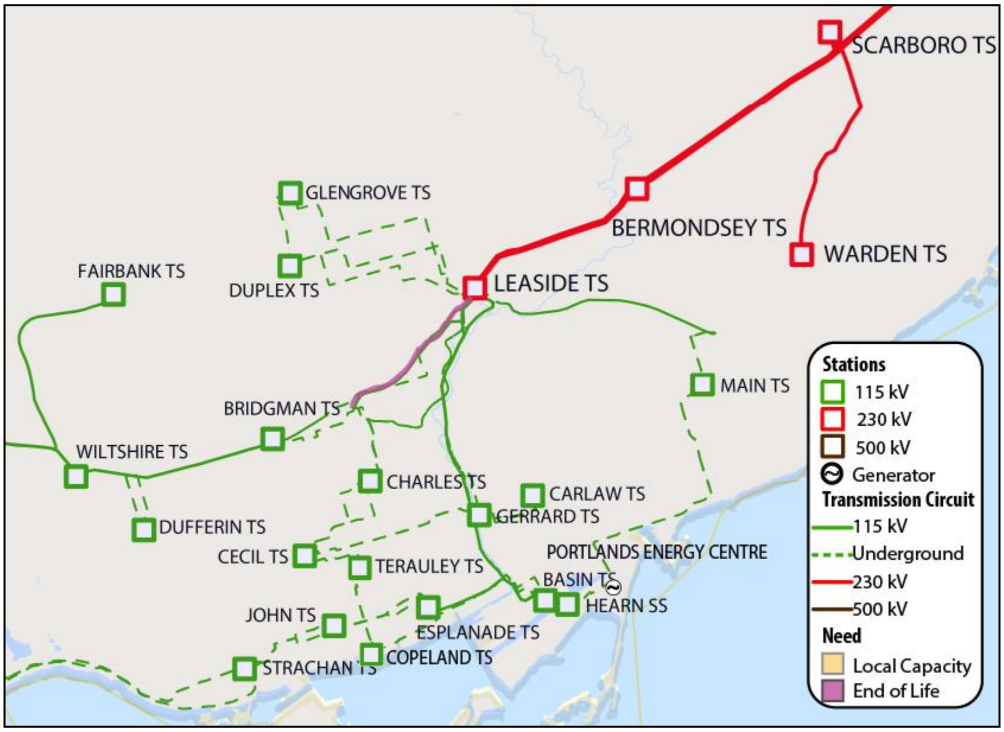
Figure 6-1: Leaside to Bloor Street Junction 115 kV Overhead Transmission Lines



Leaside to Balfour 115kV overhead transmission lines (L9C/L12C)

The 115 kV overhead transmission lines L9C and L12C provide supply to central Toronto from Leaside TS (to Cecil TS). The section of the line that runs between Leaside TS and Balfour Junction is about 3.6 km in length, and runs through the Don Valley and along an existing rail corridor (Figure 6-2). This line is more than 80 years old and the conductors have been identified by Hydro One as reaching the end of their useful life, and requiring replacement by 2023-2024 to maintain safety and reliability.

Figure 6-2: Leaside to Balfour 115kV Overhead Transmission Lines



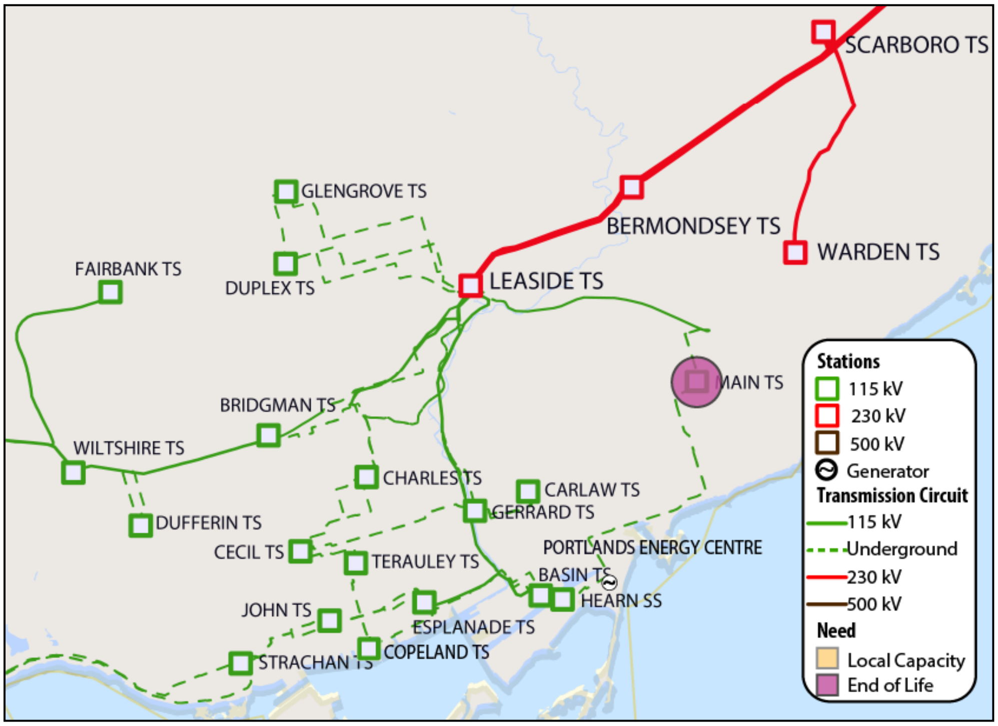
Main TS transformers and associated station equipment

Main TS is a local transformer station serving approximately 60 MW of load in east-central Toronto, including the Danforth and Beach neighbourhoods (Figure 6-3). The two transformers at the station, T3 and T4, are currently about 50 years old. Hydro One is currently working with Toronto Hydro to replace the end of life transformers, along with other equipment, such as 115 kV line disconnect switches, current transformers and voltage transformers.

Main TS is supplied by a combination of overhead and underground 115 kV circuits from Leaside TS to Hearn TS (H7L and H11L). Two sections of the original underground cable supply circuits are currently undergoing refurbishment due to their age (about 60 years old) and condition.

The station is currently more than 70 per cent utilized and resupplying the area load via adjacent station facilities is not possible. As with many established areas of the city, urban growth and development is likely in the Main TS area.

Figure 6-3: Location of Main TS



6.2.1.2 Medium-term Asset End-of-life Replacement Needs

Four asset end of life replacement needs occurring in the medium term were considered within the scope of this plan (Table 6-2). These needs are described further in this Section. The options considered for addressing these needs are described in Section 7.1.1.

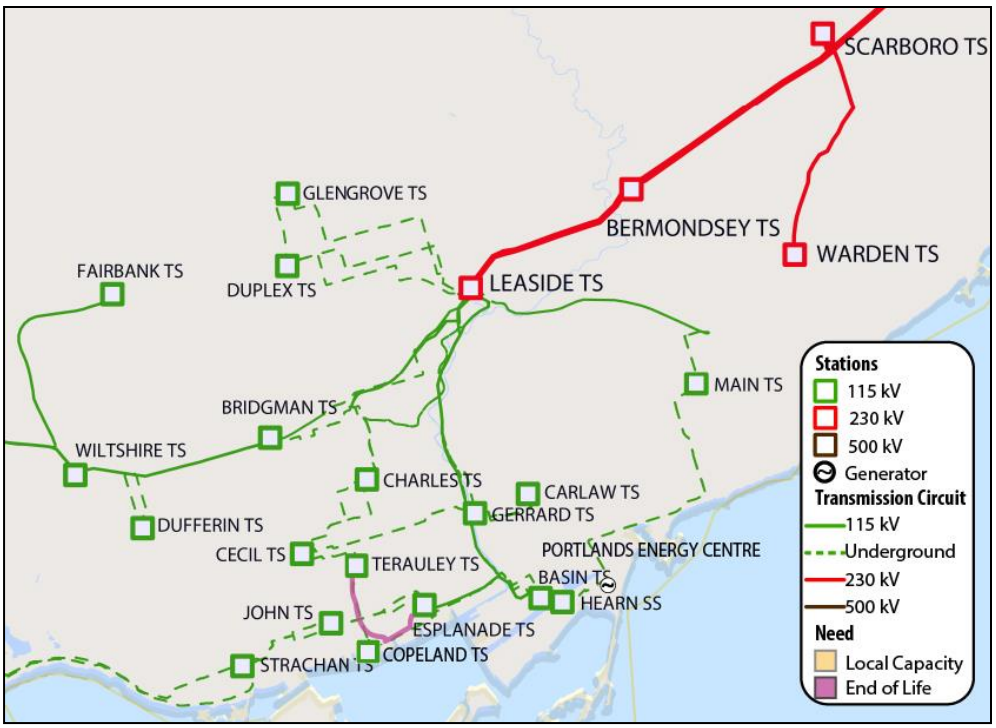
Table 6-2: Toronto Region End-of-life Asset Replacement Needs (Medium term)

Facilities	Need	Expected Timing
Esplanade TS to Terauley TS 115 kV underground transmission cables (C5E and C7E)	End of life of underground cables from Esplanade TS to Terauley TS in downtown Toronto	2024-2025
Manby TS	End of life of major station equipment, including: autotransformers T7, T9, and T12, step-down transformer T13, and the 230 kV yard	2025-2026
John TS	End of life of transformers T1, T2, T3, T4, T6, and 115 kV breakers	2026-2027
Bermondsey TS	End of life of transformers T3 and T4	2025-2026

C5E/C7E 115 kV underground transmission cables

The 115 kV underground transmission cables C5E and C7E provide supply to Terauley TS in Toronto's downtown core. Installed more than 58 years ago, these paper-insulated, low-pressure oil filled cables extend about 3.6 km from Esplanade TS to Terauley TS, and are partially routed near Lake Ontario (Figure 6-4). They have been deemed by Hydro One to be at the end of their useful life, and requiring replacement as soon as possible, given that the risk of cable failure resulting in oil leaks and adverse environmental impacts is increasing with time.

Figure 6-4: C5E/C7E 115 kV Underground Transmission Cables

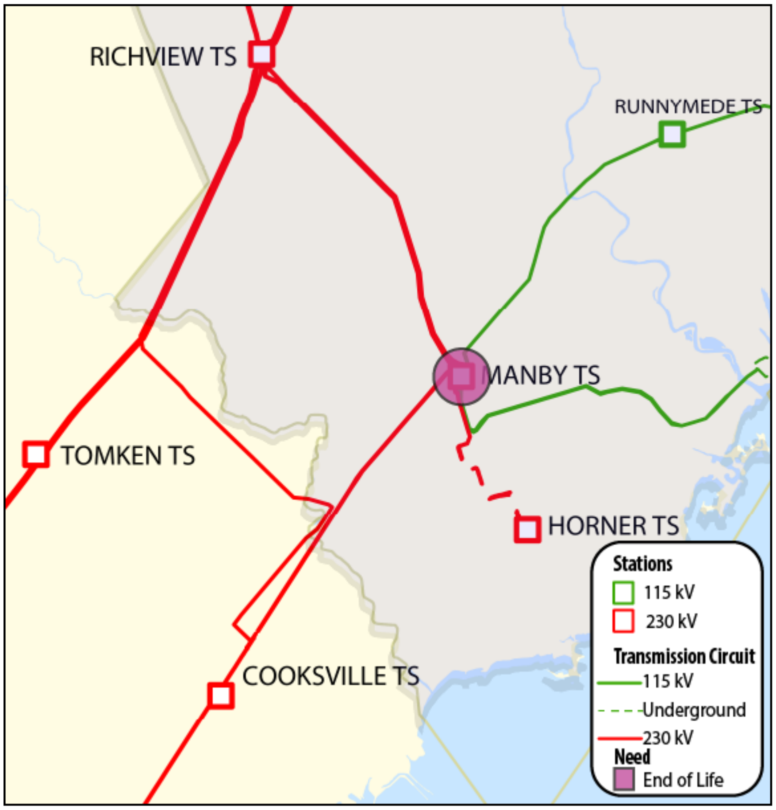


Manby TS

Manby TS is a major switching and autotransformer station supplying the western portion of the central Toronto 115 kV transmission system (Figure 6-5). Station facilities include six 230 kV/ 115 kV autotransformers (T1, T2, T7, T8, T9 and T12), a 230 kV switchyard, a 115 kV switchyard, and three DESNs with six 230/27.6 kV step-down transformers that supply customers in the immediate vicinity of the station. Three of the autotransformers (T7, T9 and T12) and one of the step-down transformers (T13) are close to 50 years old and, along with the 230 kV oil circuit breakers, have been identified to be at the end of their useful life. All of this end of life equipment is scheduled to be replaced in 2025-2026.

Addressing end of life needs at Manby TS represents a major undertaking that needs to be well coordinated in consideration of Toronto's long term needs and future supply options.

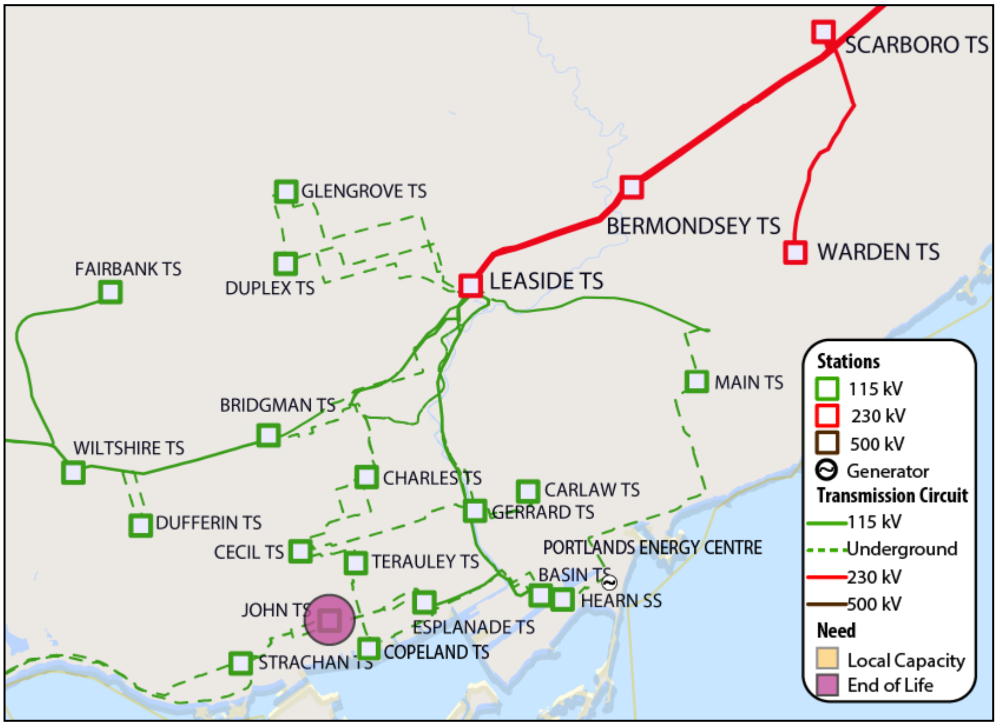
Figure 6-5: Location of Manby TS



John TS

Built in the 1950s, John TS is connected to the 115 kV Manby West system and supplies much of Toronto's downtown financial district (Figure 6-6). Station facilities include six 115/13.8 kV step-down transformers (T1, T2, T3, T4, T5 and T6) and a 115 kV switchyard. Toronto Hydro's switchgear at the station has reached the end of its useful life, and is expected to be replaced starting in 2024-2025. In addition, Hydro One has identified the step-down transformers at John TS (T1, T2, T3, T6), as well as the 115 kV breakers to be at the end of their useful life and require replacement within the near to medium term. Because of their deteriorated condition, transformer T4 has already been replaced and T1 is scheduled to be replaced in Q4 2019. The approximate timing for the station refurbishment is 2026-2027.

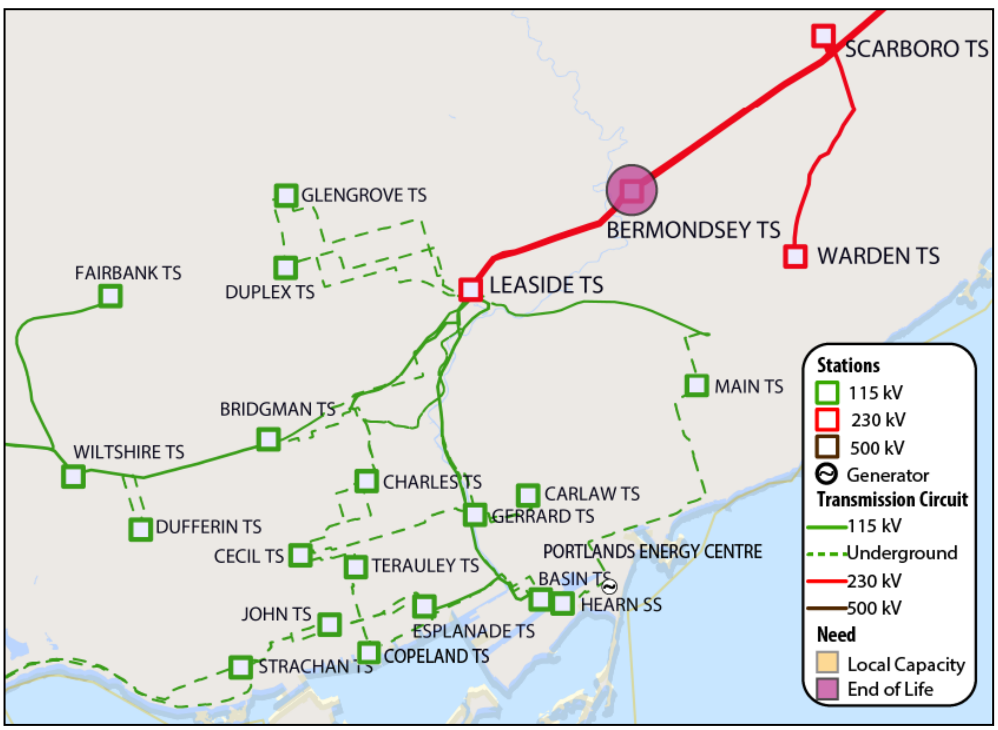
Figure 6-6: Location of John TS



Bermondsey TS

Bermondsey TS supplies customers in the western part of Scarborough (Figure 6-7). The station is comprised of two DESNs, one of which (T3/T4 DESN 2) was built in 1965, and the other (T1/T2 DESN 1) in 1990. DESN 2 has been identified by Hydro One to be at its end of life and is expected to be replaced by 2025-2026. Bermondsey TS has a total of 18 distribution feeders supplying Toronto Hydro customers: the older T3/T4 DESN 2 has 12 feeders, while the newer T1/T2 DESN 1 has six feeders. The total loading on the station is forecast to remain below its capacity over the planning horizon. This provides an opportunity to review configuration and component sizes to best meet future needs.

Figure 6-7: Location of Bermondsey TS



6.2.2 Supply Capacity Needs

Supply capacity needs at local step-down transformer stations were found at five transformer stations. A breakdown by year of the forecasted station loadings, as well as a more detailed description of the methodology for carrying out this assessment, is provided in Appendix E: Station Capacity Assessment.

6.2.2.1 Local Transformer Station Capacity Needs

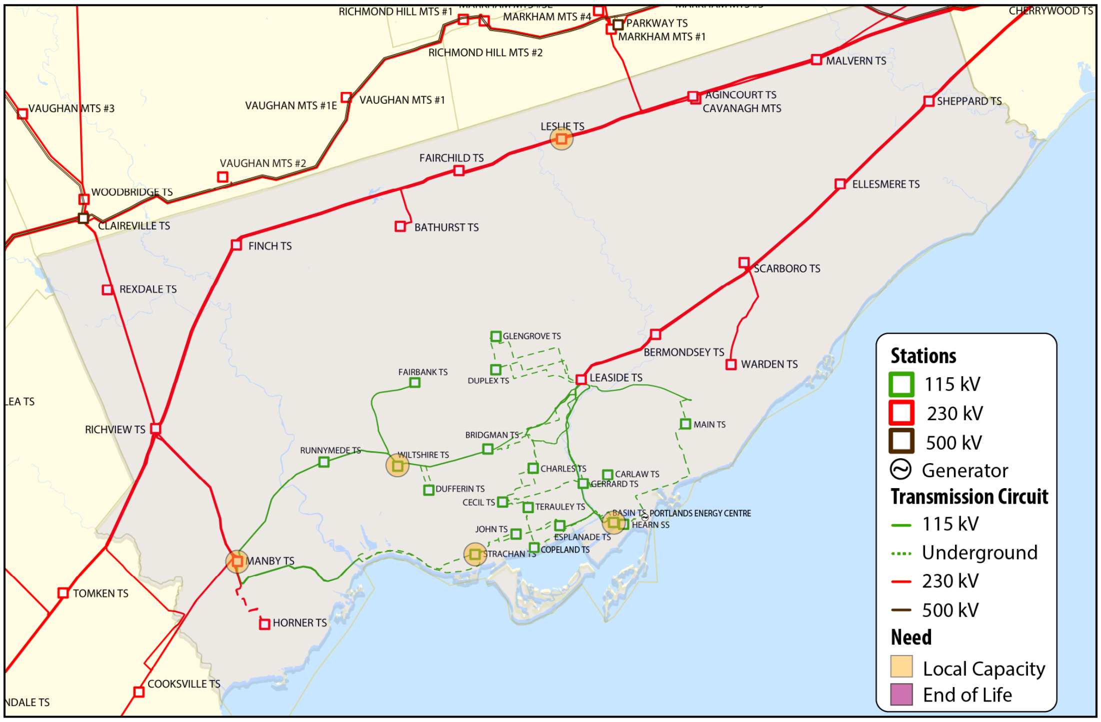
Table 6-3: Toronto Region Transformer Station Capacity Needs

Station	Description	Timing[12,13]
Manby TS	A transformer capacity need was identified for the load supplied by all three DESNs[14]	2023 for T5/T6 2032 for T3/T4 2034 for T13/T14
Strachan TS	A transformer capacity need was identified for the load supplied by both DESNs	2030 for T13/T15 2033 for T12/T14
Basin TS	A transformer capacity need was identified for the load supplied by the T3/T5 DESN (the only DESN at Basin)	2033
Leslie TS	A transformer capacity need was identified for the load supplied by the T3/T4 DESN	2033
Wiltshire TS	A transformer capacity need was identified for the load supplied by the T1/T6 DESN	2035

The locations of the local capacity needs are shown in Figure 6-8; four of the five local capacity needs are situated in the Central Toronto area.

[12] The timing presented in the table is consistent with the demand outlook provided by Toronto Hydro (net of new energy efficiency and distributed energy resources until the end of 2020); the timing of these capacity needs inclusive of future energy efficiency codes and standards is discussed in the subsections following the table.
[13] Even though local transformer station capacity needs are presented in terms of the individual DESNs within the station, for the purpose of planning and implementing solutions, the needs at each station are generally addressed as one need requiring a holistic solution.
[14] This need was identified and a solution was recommended in the 2015 Central Toronto IRRP. The status of the 2015 recommendation is discussed in Section 7.2.

Figure 6-8: Location of Local (Transformer Station) Capacity Needs



Manby TS (step-down transformation capacity)

Manby TS currently consists of three DESNs connected to the 230 kV system. This step-down transformer station, which supplies customers in the area surrounding Islington Town Centre from the Humber River west to the Toronto City limit, shares a yard with, but is separate from, the larger Manby 230/115 kV autotransformer station that provides 115 kV supply to the western portion of downtown Toronto. With a combined capacity of 240 MVA (216 MW), all three DESNs are forecast to exceed their capacity, starting in 2023 for the T5/T6 DESN 2, 2032 for the T3/T4 DESN 1, and 2034 for T13/T14 DESN 3.

The peak demand impacts of efficiency codes and standards were not taken into account for the timing of this need. Demand at Manby TS has already exceeded the station's capacity in several recent years. This issue was discussed in the 2015 Central Toronto IRRP, solutions were evaluated, and the recommendations to address the need are currently being implemented by Hydro One and Toronto Hydro. These include building a second DESN at Horner TS in south Etobicoke, and transferring load from Manby TS to the new Horner DESN.

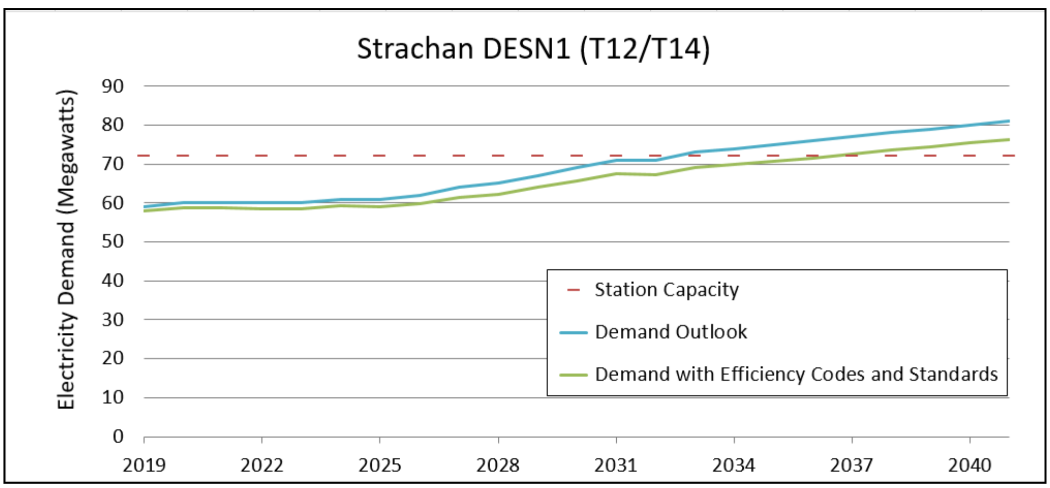
Strachan TS

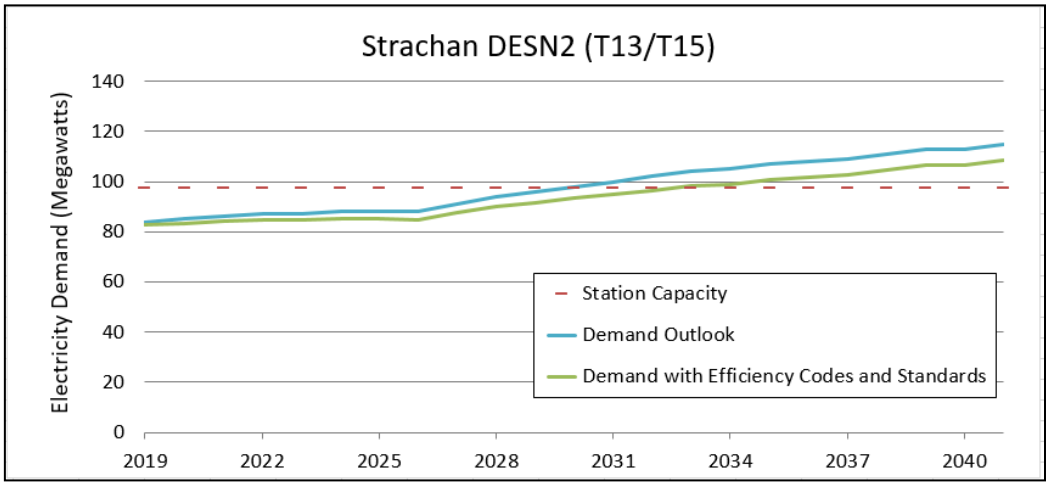
Strachan TS consists of two DESNs connected to the 115 kV system supplied from Manby TS (West Yard). Strachan TS supplies load to the west of the downtown core at 13.8 kV distribution voltage. The two DESNs have a combined capacity of 188 MVA, or 169 MW (80 MVA for T12/T14 DESN 1, and 108 MVA for T13/T15 DESN 2).

The T13/T15 DESN 2 is forecast to reach its capacity as early as 2030, while the T12/T14 DESN 1 is forecast to reach its capacity as early as 2033. Assuming the future potential impact of efficiency codes and standards, the timing of this need is deferred to 2033 and 2038 for the T13/T15 DESN 1 and T12/T14 DESN 2, respectively.

Figure 6-9 shows the demand outlook for the two DESNs at Strachan TS, as compared to the individual capacity of each DESN.

Figure 6-9: Demand Outlook for Strachan TS DESNs Compared to Capacity





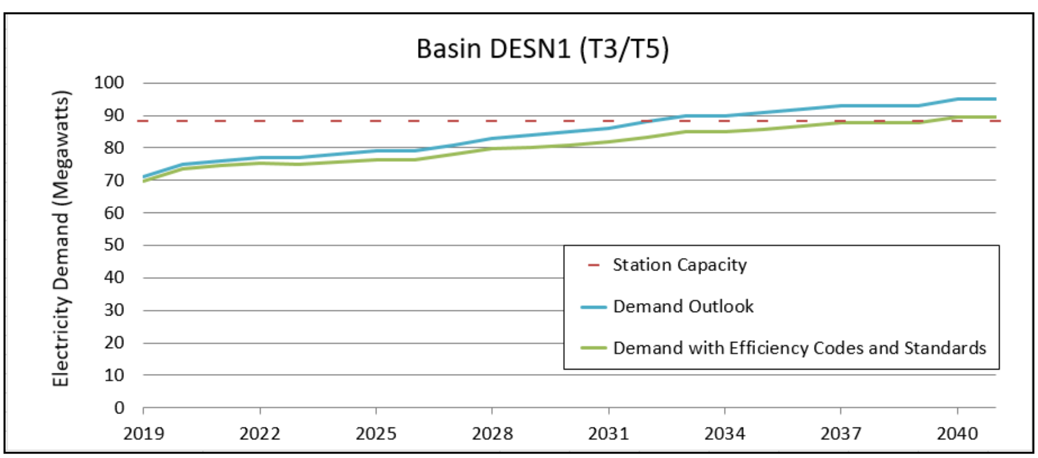
Basin TS

Basin TS has a single DESN (T1/T2) connected to the 115 kV system, supplying two low-voltage switchgear at a distribution voltage of 13.8 kV. The station has a total capacity of 98 MVA, or approximately 88 MW.

Basin TS is forecast to reach its capacity as early as 2033. Assuming the future potential impact of efficiency codes and standards (post-2020), the timing of this need is deferred to 2040.

Figure 6-10 shows the demand outlook for Basin TS, as compared to the station capacity.

Figure 6-10: Demand Outlook for Basin TS DESN Compared to Capacity



In addition to the forecast growth, the City of Toronto and Waterfront Toronto have been engaged in a master planning exercise for the Port Lands neighbourhood redevelopment and re-naturalization of the mouth of the Don River. These plans involve a number of requests to examine relocation or redesign parts of the 115 kV transmission network in and around Basin TS, including the possible relocation of Basin TS itself.

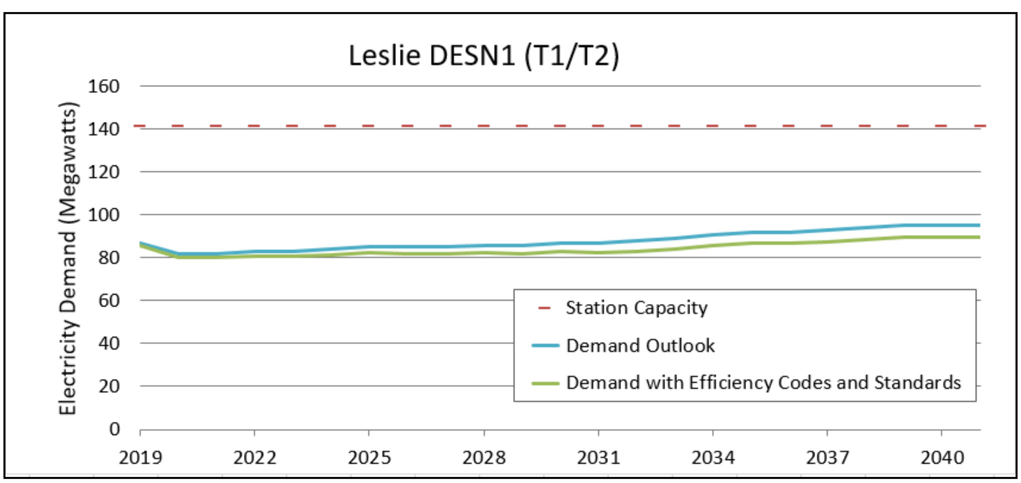
Given the absence of concrete plans and timelines for urban development in the area, the timing of the capacity need at Basin TS is uncertain.

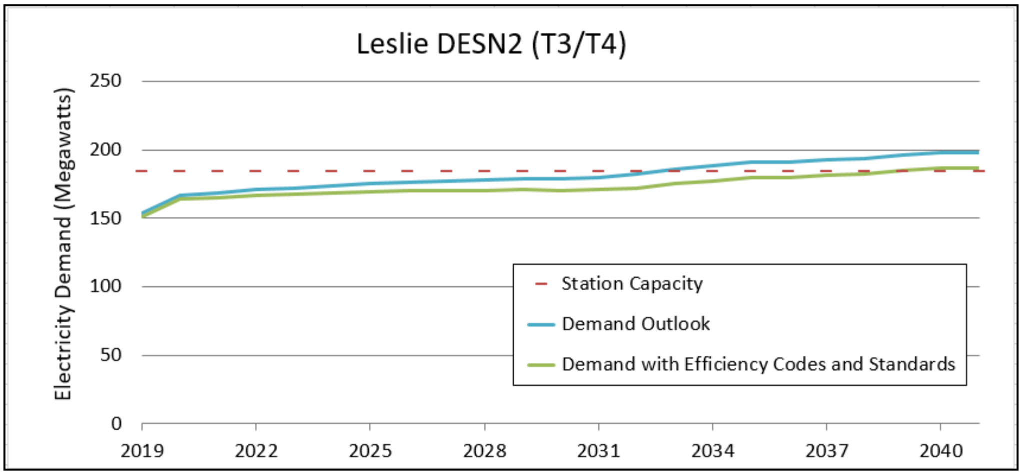
Leslie TS

Leslie TS has two DESNs connected to the 230 kV system. The T1/T2 DESN 1 supplies load at 27.6 kV and 13.8 kV, while the T3/4 DESN 2 supplies load at 27.6 kV. The total station capacity of Leslie TS is 325 MW. The T1/T2 DESN 1 has a capacity of 149 MVA (134 MW) and the T3/T4 DESN 2 has a capacity of 194 MVA (175 MW). While the other three transformers are relatively new (installed between 1988 and 2012), transformer T1, which was installed in 1963, may require replacement within the planning horizon of this IRRP, even though it has yet to be identified as being at the end of its life.

The T3/T4 DESN 2 is forecast to reach its capacity as early as 2033. Assuming the potential impact of future efficiency codes and standards, the timing of this need is deferred to 2039. Figure 6-11 shows the demand outlook for the two DESNs at Leslie TS, as compared to the individual capacity of each DESN.

Figure 6-11: Demand Outlook for Leslie TS Compared to Capacity





Wiltshire TS

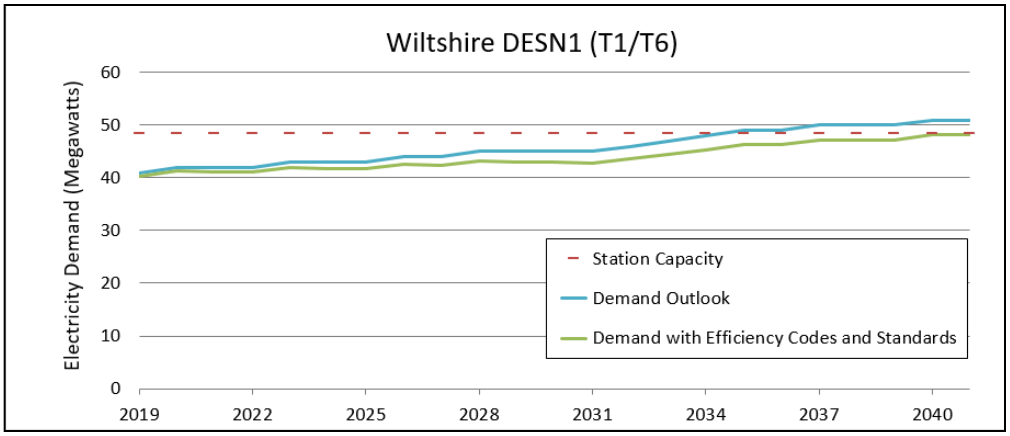
Wiltshire TS has two DESNs connected to the 115 kV system supplied from the Manby TS (East Yard). Wiltshire TS supplies customer demand to the northwest of the downtown core, including the Junction neighbourhood, at 13.8 kV distribution voltage. The two DESNs have a combined capacity of 151 MVA, or 136 MW: 51 MVA for the T1/T6 DESN 1, and 100 MVA for the T2/T7 DESN 2. These two DESNs supply three Toronto Hydro 13.8 kV buses.

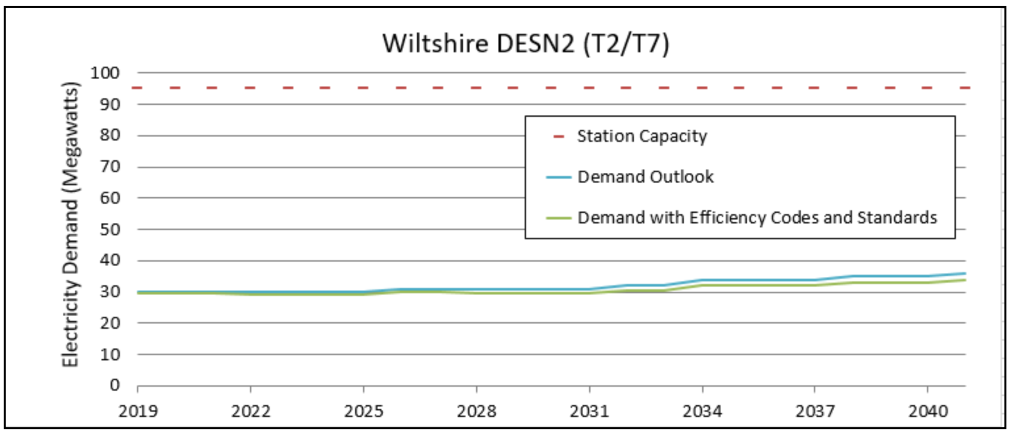
The outlook is forecasting load growth at Wiltshire TS, which can be attributed to growth and urban redevelopment in the area.

The T1/T6 DESN 1 is forecast to reach its capacity as early as 2035. Assuming the future potential impact of efficiency codes and standards, the timing of this need is beyond the study period.

Figure 6-12 shows the demand outlook for the two DESNs at Wiltshire TS, as compared to the capacity of each DESN.

Figure 6-12: Demand Outlook for Wiltshire TS DESN Compared to Capacity





6.2.2.2 Regional Supply Capacity Needs

Regional capacity needs are related to the 230 kV or 115 kV transmission system that delivers electricity from the interconnected grid into Toronto. The planning studies re-tested the need for the Richview TS to Manby TS 230 kV corridor upgrades that were recommended in the previous planning cycle. The results of this assessment reaffirm this need and are reported in this section. In the longer term, regional supply capacity needs emerge at Leaside TS, Manby TS, and on some 115 kV circuits within the Manby and Leaside Sectors.

Richview TS to Manby TS 230 kV corridor

The previous cycle of regional planning recommended that the 230 kV bulk supply to Manby TS from Richview TS be reinforced to accommodate demand growth in Toronto, primarily driven in the near term by mass transit projects. The planning studies undertaken for this IRRP re-tested the need for this additional LMC upstream of Manby TS, accounting for changes in assumptions related to the revised demand outlook provided by Toronto Hydro for the purpose of undertaking this IRRP, and the peak demand outlook for Cooksville west stations from the 2015 GTA West Needs Assessment.

The assessment confirmed that, under normal system configuration, the most limiting contingency is the loss, in 2021, of circuit R15K, which would cause R2K (also running from Richview TS to Manby TS) to exceed its capacity rating. This limitation exists regardless of whether the Metrolinx traction power substation (TPSS) is in-service; however, the additional capacity will support further mass transit electrification.

Without reinforcement to the Richview TS to Manby TS 230 kV circuits, the ability to transfer Dufferin TS to Manby East supply can become limited during summer peak conditions, following the same R15K single contingency. As discussed below (under Leaside TS and Manby TS autotransformers), transferring Dufferin TS to Manby TS supply is a possible control action in a PEC out-of-service scenario (as well as other issues that could impact supply in the Leaside TS sector). Since having this control action available helps ensure a reliable and resilient transmission supply to Toronto, the Working Group continues to recommend reinforcement of the Richview TS to Manby TS 230 kV circuits with a target in-service date as soon as possible.

The detailed assessment of the Richview TS to Manby TS corridor need is provided in Appendix F: Richview TS to Manby TS Corridor Study.

Supply to downtown Toronto from Manby West (Manby to Riverside Junction)

The Manby West supply sector comprises four 115 kV supply circuits (H2JK, K6J, K13J, and K14J), which run from Manby TS to Riverside Junction on overhead lines, with two (and in some spans, up to four) circuits on a common structure. From Riverside Junction, these circuits run underground to supply the downtown core.[15] The Manby West supply sector is considered "non-bulk" and is designed to continuously supply demand up to the loss of a single circuit.

The planning studies are showing that all four Manby TS to Riverside Junction circuits violate the reliability criteria between 2030 and 2040. Under the most severe single element loss, the remaining circuits can be as much as 120 per cent overloaded by 2040. This is a reliability concern that will need to be addressed in the long term.

Leaside TS and Manby TS autotransformers

The assessment of the Leaside autotransformer capacity is related to the presence and capacity of the 550 MW PEC facility, as both PEC and Leaside TS supply the Leaside sector. With an outage to the PEC steam turbine generator, the output of the plant would be reduced to 160 MW. Under this scenario, the Leaside autotransformers will begin to exceed their capacity limits by the 2030 to 2040 time frame, following outages on the 230 kV transmission lines that supply Leaside TS from Cherrywood TS upstream. With a full PEC outage, two of the six autotransformers at Leaside TS (T15 and T16) would be overloaded under peak demand conditions.[16]

During short-term outages of elements of PEC, system control actions to reduce the Leaside sector load through the transfer of Dufferin TS to the Manby sector will alleviate pressure on the Leaside autotransformers. While this is an acceptable short-term measure, it is not considered a permanent solution because it exposes the Manby sector, and Dufferin TS customers in particular, to supply security risks related to transmission outages in the Manby sector.

Manby TS autotransformer capacity needs were identified as emerging by the 2030 to 2040 time frame. This capacity constraint is related to the rating of the smallest autotransformer at Manby TS (T12) following the loss of a companion transformer. There may be value in factoring these findings into the end of life replacement of the Manby TS autotransformers in 2025-2026, if there is a cost-effective and technically feasible means of addressing this capacity constraint within the scope of the replacement.

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[15] The underground section from Riverside Junction to Strachan Avenue have been recently refurbished due to its age and condition.

[16] The 2030 forecast year was used to assess the full PEC outage scenario; it is likely that if such a scenario were experienced today at the time of system peak, then the Leaside TS autotransformers could experience an overload.

Bayview Junction to Balfour circuit (L15W) thermal capacity

The planning assessment shows that following the loss of circuit L14W, the companion circuit L15 (from Bayview Junction to Balfour Junction in the Leaside sector[17]) is forecast to marginally exceed its Long term emergency rating (LTE) in 2040. This need is deferred beyond the planning horizon once the forecast efficiency codes and standards savings are taken into account.

6.2.3 Load Security Needs

The transmission system must exhibit acceptable performance while following specified design criteria contingencies. The load security criteria can be found in Section 7.1 of ORTAC, and a summary of the load security criteria can be found in Table 6-4. All transformer stations in the Toronto region have at least a dual transmission supply, which allows the load served at the station to remain uninterrupted in the event of a single element contingency. Supply interruptions may occur after multiple element contingencies, but under all possible interruption scenarios, the amount of load interrupted remains within the limits prescribed in ORTAC.

Table 6-4: Load Security Criteria

Number of transmission elements out of service	Local generation outage?	Amount of load allowed to be interrupted by configuration	Amount of load allowed to be interrupted by load rejection or curtailment	Total amount of load allowed to be interrupted by configuration, load rejection, and/or curtailment
One	No	≤ 150 MW	None	≤ 150 MW
	Yes	≤ 150 MW	≤ 150 MW	≤ 150 MW
Two	No	≤ 600 MW	≤ 150 MW	≤ 600 MW
	Yes	≤ 600 MW	≤ 600 MW	≤ 600 MW

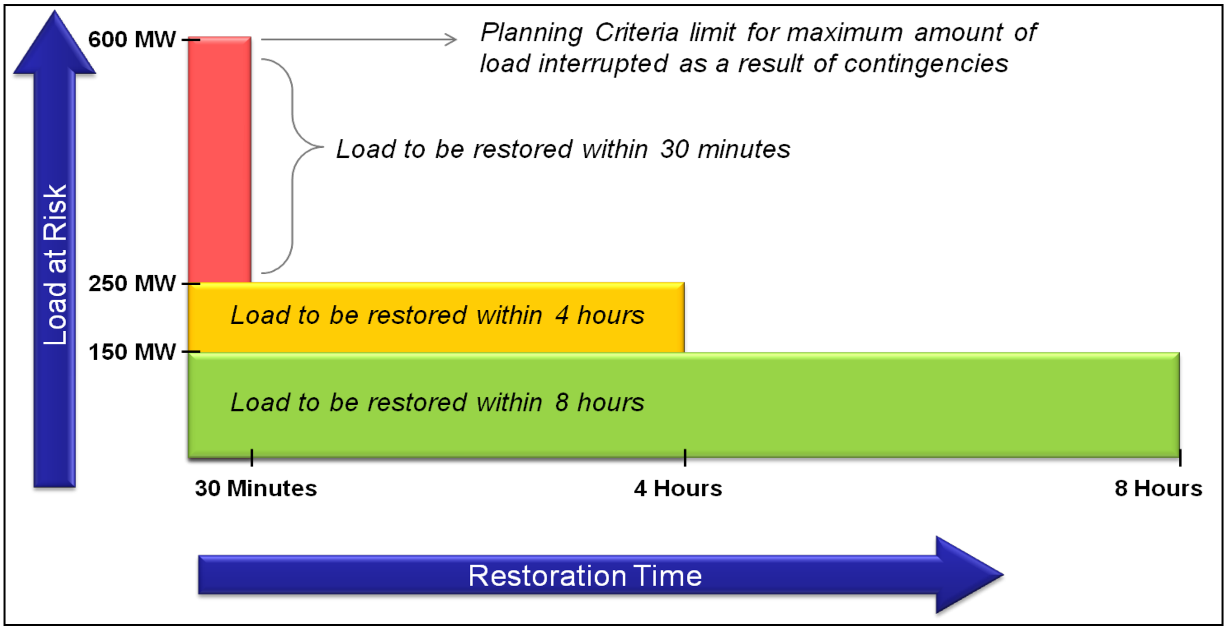
6.2.4 Load Restoration Needs

Described in Section 7.2 of ORTAC, load restoration criteria specify that the transmission system must be planned such that following design criteria contingencies, all interrupted load must be restored within approximately eight hours. When the load interrupted is greater than

[17] These circuits are part of the path supplying Wiltshire TS from Leaside TS.

150 MW, the amount of load in excess of 150 MW must be restored within approximately four hours. When the load interrupted is greater than 250 MW, the amount of load in excess of 250 MW must be restored within 30 minutes. A visual representation of the load restoration criteria is shown in Figure 6-13.

Figure 6-13: Load Restoration Criteria



No load restoration needs were identified in the Toronto region following the design criteria contingencies that were tested. Under a situation where load loss has occurred and the transmission system has been reconfigured to restore power, but some customers are still experiencing an outage, additional measures may be taken in the operational time frame. These measures may include dispatching crews to repair the transmission system, reconfiguring the transmission or distribution system to transfer load to another delivery point, and use of temporary facilities, etc. Although electricity interruptions can not be eliminated, where possible, the system operator, transmitter, and distributor will undertake measures in real time to respond to outages and restore load as quickly as possible.

6.2.5 Discretionary Reliability Needs

Reliability performance is, in part, a function of the criteria that the transmission system needs to meet. In other words, the planning criteria stipulate the functional requirements of the transmission system to ensure reliability performance. Within Toronto, specific criteria apply to different parts of the transmission system because of the function and resulting consequences of the loss of those different parts. In other words, less stringent criteria generally apply to transmission facilities where the impact is only local. Conversely, more stringent criteria apply when the consequences of a loss have a wider impact on the interconnected grid. The stringency of the planning criteria is commensurate with the severity of the consequence of contingencies that can impact the interconnected grid.

While, for study purposes, this plan applied the more stringent criteria to all parts of Toronto's transmission system (e.g., by assessing 'local area' facilities against 'bulk power system' criteria), not all areas are required to meet the more stringent criteria. ORTAC (Section 7.4) permits higher levels of reliability to be adopted for specified reasons. The results of the assessment in this study highlighted some 'discretionary reliability needs' for the purpose of generating insights as to where there may be opportunities to improve performance, but for which actions to resolve them are not required by the performance criteria that govern the planning and design of the electric power system. The discretionary reliability needs are documented in Appendix D: Toronto IRRP Study Results.

6.2.6 System Resilience for Extreme Events

One of the key measures of a resilient transmission system is its ability to withstand interruption, or restore supply during or after extreme events that impact many parts of the system. This section summarizes the capability, following analysis, of Toronto's regional transmission system to maintain supply and manage the risk posed by low-probability, high-impact events.

In 2013, the IESO conducted an assessment of the amount of load that could be restored following specific extreme contingencies involving the system that supplies downtown Toronto. The results of this assessment have not been made public due to security concerns related to the disclosure of critical energy infrastructure information and possible system vulnerabilities.

For this IRRP, key scenarios from the 2013 study were re-examined for the years 2020 and 2025. These include the loss of:

- Manby TS 115 kV switchyard
- Leaside TS 115 kV switchyard
- Four circuit tower structures emanating from the Manby TS and Leaside TS 115 kV switchyards

The results of the updated analysis found that the impact of the extreme contingencies on the 115 kV transmission system was limited to load interruptions within the Toronto region.

6.3 Summary of Needs Identified

Table 6-5 summarizes the electric power system needs identified in this IRRP. Note that discretionary needs identified in Section 6.2.5 are not included because these issues are flagged as potential opportunities to enhance reliability to Toronto but they do not require actions to address them at the present time.

Table 6-5: Summary of Needs Identified

Facilities	Need	Expected Timing
End-of-Life Assets		
Leaside Junction to Bloor Street 115 kV overhead transmission lines (H1L/H3L/H6LC/H8LC)	End of life of the approximate 2 km overhead line sections	2022-2023
Leaside TS to Balfour Junction 115 kV overhead transmission lines (L9C/L12C)	End of life of the approximate 3.6 km overhead line sections	2023-2024
Main TS	End of life of transformers T3 and T4, 115 kV line disconnect switches, and 115 kV current voltage transformers	2021-2022
Esplanade TS to Terauley TS 115 kV underground transmission cables (C5E and C7E)	End of life of underground cables from Esplanade TS to Terauley TS in downtown Toronto	2024-2025
Manby TS	End of life of major station equipment, including: autotransformers T7, T9 and T12, step-down transformer T13, and the 230 kV yard	2025-2026
John TS	End of life of transformers and 115 kV breakers	2026-2027
Bermondsey TS	End of life of transformers T3 and T4	2025-2026
Local Transformer Station Capacity		
Manby TS (DESN)	A transformer capacity need was identified for the load supplied by all three DESNs	2023
Strachan TS	A transformer capacity need was identified for the load supplied by both DESNs	2030

Facilities	Need	Expected Timing
Basin TS	A transformer capacity need was identified for the load supplied by the T3/T5 DESN (the only DESN at Basin)	2033
Leslie TS	A transformer capacity need was identified for the load supplied by the T3/T4 DESN	2033
Wiltshire TS	A transformer capacity need was identified for the load supplied by the T1/T6 DESN	2035
Regional Capacity		
Richview TS to Manby TS 230 kV Corridor	Load meeting capability upstream of Manby TS	2021
Supply to downtown Toronto from Manby West (Manby to Riverside Junction)	Load meeting capability of the 115 kV lines supplying downtown Toronto	2030-2040
Leaside TS and Manby TS	A capacity need was identified for Leaside TS and Manby TS 230/115 kV autotransformers	2030-2040
Bayview Junction to Balfour Junction Circuits	Overloading of L15 circuit for the loss of its companion circuit, L14W	2040

7. Plan Options and Recommendations

This section outlines the options considered to address transmission needs in the Toronto region, as well as the recommended plan with respect to each of these needs.

In considering options and developing recommendations, the Working Group has been mindful of the interest and preference, communicated through engagement with stakeholders, such as the City of Toronto, a local advisory committee that was in place from 2016 to 2018, and the general public, to explore NWAs, such as DERs, for dealing with electricity system needs.

Given the interest in NWAs as possible solutions for addressing Toronto's regional transmission needs, additional context on the changing landscape with respect to these resources, and on the approach to considering them, is provided below.

DERs as options to address needs in Toronto

The uptake in DERs across the province over the last decade is having an impact on the electricity system, both in terms of system demand and operability. While centralized procurement programs that supported the development of most DERs[18] are no longer in place, DER deployment is expected to continue in Toronto. Toronto Hydro has filed investment plans for approval with the OEB to increase its ability to connect DERs to its system, and the IESO has expressed support for these plans.[19]

Much of the IESO's recent work with respect to DERs has focused on identifying the barriers to their development as alternatives to wires-based solutions, and options for reducing or overcoming those barriers. Specifically, the barriers to implementation of cost-effective NWAs, including DERs, in regional planning are being investigated as part of the IESO's regional planning review initiative.[20] Further, a number of DER-focused initiatives are being undertaken as part of the work plan associated with the IESO's *Innovation Roadmap*.[21] These initiatives

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[18] Since 2006, nearly 2,000 distributed energy resources (DERs), including solar PV, CHP, energy storage and wind, have connected to Toronto's distribution system.
[19] See Toronto Hydro's rate application EB-2018-0165, Exhibit 2B, Section E7.2; and Exhibit 2B, Section B, Appendix F for IESO's Comment Letter.
[20] Launched in 2018, the regional planning review process is exploring a number of enhancements to regional planning, including potential barriers to non-wires solutions, opportunities for coordination between bulk system planning, community energy planning and market renewal, and a long term approach to replacing end-of-life transmission assets.
[21] http://www.ieso.ca/en/Get-Involved/Innovation/Innovation-Roadmap

include research and white papers, demonstration and evaluation projects, and capital projects and process improvements. For a full list and descriptions, visit the innovation projects page on ieso.ca.

The Working Group believes that DERs need to continue to be studied to build the necessary tools and experience required to consider and evaluate them as potential solutions to regional electricity needs. This work is being undertaken through the above mentioned work plan. In the meantime, continued dialogue with the community is expected to play an important role in defining the potential for cost-effective NWA solutions. Further details are provided in the plan recommendations.

7.1 Evaluating Plan Options for Addressing Needs Identified in Toronto

The following sections describe the options considered to address the needs identified in Section 6.2.

The evaluation of possible plan options takes into consideration a number of factors, including technical feasibility, timing, cost, and alignment with local priorities. In light of the importance of cost as a planning consideration, solutions that are cost-effective and that maximize the use of existing infrastructure and assets are typically given priority for inclusion in the evaluation.

To help ensure that solutions will be available in time to address pressing needs, the IRRP identifies specific actions to be undertaken and/or implemented in the near and medium term. Given forecast uncertainty and the potential for technological and policy changes, investment in longer-term needs is not prudent at this point in time. Instead, the long term plan focuses on developing and maintaining the viability of long term options, engaging with communities, and gathering information to lay the groundwork for making decisions on future options.

As discussed in Section 6, solutions are needed to address (1) end of life asset replacements; (2) local transformer station capacity, and (3) regional supply capacity needs. In addition, the plan identifies some discretionary needs related to maintaining a higher level of reliability performance than those prescribed in ORTAC. This recognizes Toronto's position as the largest urban centre in Canada, and the ORTAC provision allowing the transmission customer and transmitter to agree on higher (or lower) levels of reliability. Firm recommendations to address discretionary needs are dependent on the availability of cost-effective solutions and the risk of the need materializing.

In developing the plan, the Working Group examined a range of solutions to address the near term needs, as well as activities to begin to lay a foundation for addressing needs in the longer term. These options are discussed and evaluated in the following sections.

7.1.1 Options for Addressing End of Life Asset Replacement

When transmission equipment reaches end of life, a number of alternatives can be considered. Transmission or distribution facilities may have changed since the equipment was built, community needs may have evolved, equipment standards may have changed, and/or opportunities for other options, such as energy efficiency, may be able to play a role.

Options to address end of life asset replacement needs in the Toronto region included:

- Retiring the asset or facilities
- Replacing the assets to the "right size" (e.g., larger or smaller) based on considerations, including future electricity demand, or changes to the use of the asset to realize reliability, resilience, or other benefits that an alternate configuration may provide
- Replacing the assets "like for like" or with the closest current equivalent
- Implementing NWAs

Based on the assessments conducted in this IRRP, each of the assets reaching its end of life in this plan was deemed critical for maintaining a sufficient and reliable supply of electricity to customers. As such, and given the magnitude and persistence of the needs, complete retirement and replacement with NWAs was screened out as an alternative in favour of replacing the assets with the closest available equivalent.

Leaside Junction to Bloor Street Junction 115 kV overhead transmission lines (H1L/H3L/H6LC/H8LC)

Three options were assessed to inform the preferred approach for addressing this end of life overhead line section:

1. **Replace the existing lines with 230 kV capable lines to increase future capacity (but continue to operate at 115 kV, for now):** This approach was ruled out because assessment indicated that none of these circuits would be thermally limited within the planning horizon. Also, because there is no plan to increase the transmission supply voltage (e.g., to 230 kV) to any of the stations supplied by the HxL or HxLC circuits, there would be no benefit for investing in replacement circuits at a higher operating voltage (or any associated tower investments) within the planning horizon.

2. **Replace the existing lines with 115 kV lines (like for like, built to current standards):** The planning assessments show that the LMC of the 115 kV transmission lines is adequate to supply the needs of Toronto within the planning horizon. New 115 kV transmission lines along this path built to today's standards are expected to be able to carry more load, and operate in a more reliable manner, as compared to the existing equipment.

3. **Replace end of life assets with NWAs:** As NWAs, such as energy efficiency or DERs, would be very expensive compared to replacing end of life assets, the Working Group determined that they do not present a viable approach.

Table 7-1 summarizes the considerations related to the options. Based on the evaluation of the alternatives, this IRRP recommends that Hydro One proceed with like for like replacement of the end of life line sections.

Table 7-1: Options for Addressing Leaside Junction to Bloor Street Junction 115 kV Lines

	Replace with 230 kV capable	Replace like for like
Summary of Option	• Rebuild the existing line section to meet 230 kV standard	• Refurbish the existing line section with the equivalent voltage standard
Potential Benefits	• Maintain capacity (if energized at 115 kV) or increase capacity (if energized at 230 kV) • Maintains reliability • Contributes to introducing 230 kV supply to downtown	• Maintain or improve capacity and reliability • Better in-service date certainty
Potential Risks/ Issues	• If never energized at 230 kV, incremental costs for 230 kV capability will not provide value	• None if the work is scheduled and completed outside of the peak demand season

Leaside TS to Balfour Junction 115 kV overhead transmission lines (L9C/L12C)

These two lines are critical for supplying Toronto's electricity needs. Three options were assessed to inform a recommendation on the preferred approach to address this end of life overhead line section:

1. **Replace the existing lines with 230 kV capable lines (but continue to operate at 115 kV for now):** This approach was ruled out because assessment results indicated that none of these would be thermally limited within the planning horizon. Since there is not a plan to increase the transmission supply voltage to any of the stations supplied by these lines, it would not be beneficial to invest in replacement circuits at a higher operating voltage (or any associated tower investments).

2. **Replace the existing lines with 115 kV lines (like for like, built to current standards):** The planning assessments show that the LMC of the 115 kV transmission lines is adequate to supply the needs of Toronto within the planning horizon.

3. **Replace end of life assets with NWAs:** Given that energy efficiency, DERs and other NWAs would be very expensive compared to replacing end of life assets, the Working Group determined that NWAs do not present a viable approach.

Table 7-2 summarizes the considerations related to the options. Based on the evaluation of the alternatives, this IRRP recommends that Hydro One proceed with like for like replacement of the end of life line sections.

Table 7-2: Options for Addressing Leaside TS to Balfour Junction Transmission

	Replace with 230 kV	Replace like for like
Summary of Option	• Rebuild the existing line section to meet 230 kV standard	• Refurbish the existing line section with the equivalent voltage standard
Potential Benefits	• Maintain capacity (if energized at 115 kV) or increase capacity (if energized at 230 kV) • Maintain reliability • Contributes to introducing 230 kV supply to downtown	• Maintain or improve capacity and reliability • Better in-service date certainty
Potential Risks/ Issues	• If never energized at 230 kV, incremental costs for 230 kV capability will not provide value	• None if the work is scheduled and completed outside of the peak demand season

Main TS

The IRRP looked at different approaches for addressing end of life assets at Main TS, which include the two step-down transformers and associated medium-voltage switchgear. Eliminating the station outright was not considered to be a feasible option, as it is over 70 per cent utilized and resupplying the customer demand in the area from adjacent station facilities is not possible with the existing infrastructure.

NWAs, including energy efficiency or DERs, are not suitable options for addressing asset condition-related needs. As an alternative to the step-down station, energy efficiency or DERs would be cost prohibitive as compared to replacing end of life assets.

Other options were considered and are discussed below:

1. **Converting Main TS to 230 kV operation:** Providing a 230 kV connection to Main TS could be achieved by rebuilding the existing 115 kV supply circuits from Leaside TS (H7L and H11L), or by building a new 230 kV line. New 230 kV transformers and associated high-voltage switchgear would be needed at the existing station, or at a new station location. The 115 kV rebuild option would make the existing H7L and H11L circuits unavailable to supply Hearn station from Leaside TS, while building a new 230 kV connection would be very expensive. In addition, as Main TS is space constrained, the larger 230 kV transformers may not be accommodated on the existing site. As property for building a new station in the vicinity is also limited, this alternative was deemed not viable.

2. **Supplying Toronto Hydro's switchgear from new transformers at Warden TS:** As this approach would require the building of several new distribution cable circuits from Warden TS, which is 4.5 km from Main TS, the Working Group determined that this alternative would be expensive, and impractical, considering the number and length of new distribution cables required.

3. **Replacing the transformers at the existing Main TS location with new 115 kV transformers:** This approach is technically feasible and can be accommodated at the existing station location. Given the potential for future high density urban development in the Main TS service area, Toronto Hydro has recommended, that the existing 45/75 MVA transformers at Main TS be replaced with 60/100 MVA transformers. Even with the cost differential between the two transformer sizes – which Hydro One has estimated to be about $300,000 – the cost of this approach is far less than either option 1 or 2. The Working Group supports this recommendation.

Options 1 and 2 above would have the benefit of shifting load from the 230 kV/ 115 kV autotransformers at Leaside TS to the 230 kV system, providing capacity relief for the Leaside TS autotransformers. Option 3 is the most cost-effective, even with the marginal additional cost of replacing the existing 45/75 MVA transformers with 60/100 MVA transformers.

Table 7-3 summarizes the options assessed to address the end of life asset needs at Main TS.

Table 7-3: Options for Addressing Main TS End-of-life Assets

	Convert to 230 kV	Supply Main TS area from Warden TS	Replace Transformers at Main TS
Summary of Option	• Replace existing transformers with 230 kV transformers; rebuild the circuits supplying Main TS to 230 kV	• Install new 230 kV transformers at Warden TS and supply Main TS service area with new distribution cables from Warden TS	• Replace existing transformers at Main TS with new transformers; take the opportunity to install higher capacity transformers to supply future development in the area
Potential Benefits	• This option would provide relief to the Leaside TS 230 kV /115 kV transformers as it would move Main TS to 230 kV supply	• This option would provide relief to the Leaside TS 230 kV/ 115 kV transformers as it would move Main TS to 230 kV supply	• This option maximizes use of the existing infrastructure supplying the area • Provides capacity for area growth and development
Potential Risks/ Issues	• The cost would be very high • Capacity relief at Leaside TS may only be needed at or beyond the planning horizon • Main TS is a small station; this option may not be feasible	• The technical feasibility of running very long distribution feeders from Warden to Main TS load is uncertain; there may be reliability impacts • The cost would be very high • Capacity relief at Leaside TS may only be needed beyond the planning horizon	• This option does not provide capacity relief for Leaside TS, which may only be needed beyond the planning horizon • Does not preclude upgrading to 230 kV at a later date

C5E/C7E 115 kV underground transmission cables

Given the complexity and lead time required to implement underground infrastructure through downtown Toronto, Hydro One launched an EA process for the cable replacement in May 2018. Community engagement related to the options is currently underway, with five underground routes under consideration. The route investigation will consider stakeholder input, and assess existing easements and rights-of-way, costs, and other technical and environmental considerations. OEB Leave to Construct approval will also be required.

Since the Working Group has determined that there are no suitable alternatives to replacement, this IRRP recommends that Hydro One continue with actions to replace the existing 115 kV cables.

Manby TS

Given the extent of end of life assets at Manby TS, development of a well-coordinated plan will need to consider the capacity of the station to meet future growth needs in Toronto, accommodate additional short-term transfers to the Manby sector in the event of emergencies (such as a loss of Leaside sector supply or PEC outages), and maintain reliability. For example, the plan required to address the assets reaching end of life in the 230 kV switchyard should be coordinated with the remedial action scheme (RAS) recommended in the 2015 Central Toronto IRRP, with the new terminations required to accommodate the new Richview to Manby TS circuits, and the long term need for additional capacity to supply growth in downtown Toronto. NWAs were ruled out as feasible alternatives to address this end of life need.

The Working Group will continue to assess transmission options and develop a recommendation concerning the significant end of life asset needs at Manby TS. It is recommended that this work commence in the RIP.

John TS

The end of life needs at John TS represent a major undertaking that needs to be coordinated with other plans to reinforce step-down supply capacity in the downtown core, including Toronto Hydro's Copeland TS (Phase 1 and Phase 2). For example, Copeland TS will provide an opportunity to review the configuration and major equipment capacity (i.e., right sizing) at John TS, to ensure it meets future needs. Furthermore, the 115 kV station design is in a "ring-bus" configuration and the end of life need provides an opportunity to review this configuration, while considering costs, operational flexibility, reliability to customers and transmission system development plans in the area.

Coordination of this work with Copeland TS is vital for providing the additional capacity to facilitate outage planning at John TS for the execution of a replacement plan, while maintaining reliable supply in Toronto's downtown district. Since this need is driven by the condition of the assets, NWAs were ruled out as feasible alternatives to address this end of life need.

The Working Group therefore recommends that the replacement plan for end of life equipment at John TS be further assessed through continued coordinated planning, commencing with the RIP.

Bermondsey TS

The station load is forecast to reach about 173 MW over the study period, after accounting for energy efficiency codes and standards. While there is a continuing requirement for the station to supply customers in the area, the total load on Bermondsey TS is forecasted to remain well below its current capacity over the planning horizon.

The options for addressing the asset end of life need at Bermondsey TS are summarized as follows:

1. **Retire (and decommission) the T3/T4 DESN at its end of life:** This option would mean supplying the entire load at Bermondsey TS from the T1/T2 DESN, and expanding the switchyard to accommodate new feeders (i.e., transferring the 12 feeders from the T3/T4 DESN to the T1/T2 DESN). However, this intra-station transfer would result in the remaining DESN nearing its capacity limit by the end of the study period.

2. **Replace the 84/140 MVA and 75/125 MVA end of life transformers with smaller 50/83 MVA transformers:** According to Hydro One, the cost of feeder work would be significantly more than the $600,000 savings for smaller size transformers ($300,000 per transformer).

3. **Replace like for like:** Based on the information available, this option will minimize the cost of end of life work at the station, while retaining some ability to grow and accommodate transfers within the station.

Based on the options put forth, NWAs were screened out at a feasible option to address this end of life need. Further assessment is needed to determine the cost and feasibility of option 2, above. The Working Group therefore recommends that a plan be developed within the scope of the RIP.

7.2 Options for Addressing Supply Capacity Needs

Based on the demand outlook, capacity needs in the Toronto region are centered on a number of transformer stations (DESNs) supplying local neighbourhoods in the city.

Local transformer station capacity needs at Manby TS, Strachan TS, Leslie TS and Wiltshire TS

For the need at Manby TS, the 2015 Central Toronto IRRP recommended that a second DESN be built at the adjacent Horner TS. Part of the rationale for the Horner TS expansion was to provide relief for Manby TS through permanent load transfers. The second DESN is expected to be in-service by late 2021.

The station capacity needs at Strachan TS, Leslie TS and Wiltshire TS are far enough into the future that there is sufficient time to monitor demand changes and revisit these needs in the next planning cycle. Further, based on a preliminary review of possible approaches, capacity is available either at other DESNs within the station, or at adjacent stations to permit planning for load transfers to provide relief to the DESNs that are forecast to reach their capacity. These transfers will require planning and investment to implement.[22]

To address the capacity need at Strachan TS, the capacity that is expected to be made available by Copeland TS (Phase 1 and Phase 2) is likely to allow for a permanent load transfer. While the feasibility of implementing such a transfer is not yet clear, there is sufficient time to monitor growth and assess the feasibility of various options. If demand grows faster than anticipated, or the forecast for energy efficiency changes, additional measures to address future capacity needs at Strachan TS – such as energy efficiency or other NWAs – can be explored and implemented, provided they are feasible and cost-effective.

[22] These types of actions are normally undertaken by the distributor as part of distribution system planning.

For the needs at Leslie TS and Wiltshire TS, capacity at other DESNs within the station is sufficient to accommodate additional load. This work will be undertaken by Toronto Hydro and Hydro One, with enough lead time to plan and implement intra-station transfers, if and when they are needed.

Local station capacity need at Basin TS

The capacity need at Basin TS arises as early as 2033; however, after considering the impact of efficiency codes and standards, the timing could be deferred to 2040. That said, a number of complicating factors related to the uncertainty of future demand growth at Basin TS must be taken into account. These relate to:

- Planned urban developments at the site and neighbourhood level
- City-led district energy plans
- The potential for economic growth, specifically related to intensification of commercial activity, for example, at the former Unilever site and the film studio district
- The relocation – proposed by the City of Toronto and Waterfront Toronto – of a significant number of existing high-voltage transmission facilities in the area

These uncertainties will impact the scope and timing of the needs, as well as the configuration of the electricity infrastructure in the area, including the ultimate size and location of Basin TS.

Cost-effective NWAs, including DERs and energy efficiency, should be explored to defer the needs at Basin TS, once they are further defined. Ongoing dialogue with stakeholders will be required to help identify feasible and cost-effective solutions, as well as prospective developments that could address the specific characteristics and timing of needs in the area. Since this is driven primarily by the need to supply local customers within Toronto Hydro's service territory, the Working Group agrees that the assessment of NWAs as potential solutions should be coordinated by Toronto Hydro.

7.3 Options for Addressing Regional Supply Capacity Needs

Options to address the regional supply capacity needs identified in Toronto are described below.

Richview TS to Manby TS 230 kV corridor

Options to address this need were assessed in the 2015 Central Toronto IRRP, the 2017 IRRP Addendum and the 2016 RIP by Hydro One. Since then, there have been no material changes to either the scope of the options or the preferred approach, which is planned to occur in the following two phases:

- **Phase One:** Rebuild the existing idle 115 kV overhead line on the transmission corridor between Richview TS and Manby TS to 230 kV. The new line will operate in parallel with the existing four 230 kV circuits from Richview TS to Manby TS, which will initially be reconfigured to create two "supercircuits." This will allow for the two additional circuits to supply Manby TS, but avoid the need to build new terminations, including new breakers at Manby.
- **Phase Two:** To be coordinated with the Manby TS end of life refurbishment, new circuits will be separately terminated on the Manby 230 kV bus, and at Richview TS they will connect to existing 230 kV circuits between Claireville TS and Richview TS, thereby unbundling the two supercircuits. The scope and timing for this work will be addressed starting with the RIP.

Based on the assessments undertaken by the IESO, the IRRP Working Group recommends that Hydro One proceed with the reinforcement of the Richview TS to Manby TS 230 kV transmission reinforcement project, including initiating community engagement, the EA, and OEB Section 92 Application for Leave to Construct.

Supply capacity at Leaside TS and Manby TS autotransformers, Manby TS to Riverside Junction lines, and Bayview Junction to Balfour Junction circuit section

These regional capacity needs do not emerge until between 2030 and 2040, depending on the assumptions around continued gains in energy efficiency resulting from efficiency codes and standards.

Leaside TS and Manby TS needs are related to the 230 kV/115 kV autotransformer capacity limits. The Manby TS to Riverside Junction line needs are related to the ability to supply the demand when there is a loss of a companion circuit. The Bayview Junction to Balfour Junction needs emerge in 2040 and are related to the thermal rating of the 115 kV circuit, when there is a loss of the companion circuit.

Cost-effective NWAs, including DERs and energy efficiency, remain possible options to address each of these longer-term regional supply capacity needs. Ongoing engagement with stakeholders and the community will be important for understanding the potential for these types of options going forward. It will also be essential to gather enough information on the nature and timing of these needs to understand what performance and cost attributes NWA options will be required to address them.

7.4 Options for Addressing Discretionary Reliability Needs

These needs are included in Appendix D as discretionary because they represent possible opportunities to maintain and/or enhance the reliability of supply above the minimum performance standards prescribed in ORTAC. Their inclusion in this IRRP recognizes the importance of a reliable electricity supply to an urban centre like Toronto, should feasible, cost-effective options for improving reliability emerge as an outcome of continued planning, coordination, and engagement with electricity sector stakeholders and the community.

Although no specific solution options have been explored in the scope of this plan, these issues should be revisited in future plans, or as other opportunities arise to assess the adequacy and/or resilience of the system, including when assets approach their end of life.

7.5 The Recommended Plan

This IRRP re-affirms the needs and plans identified in the previous regional planning cycle that concluded in January 2016, and recommends the actions described below to address region's transmission needs until at least the late 2020s or early 2030s.

Replace end of life overhead line sections H1L/H3L/H6LC/H8LC and L9C/L12C

Both of these overhead line sections were deemed critical for maintaining a sufficient and reliable supply of electricity to customers in Toronto. The Working Group recommends that Hydro One proceed with planning for the like for like replacement of these overhead line sections.

Replace end of life transformers at Main TS

Both transformers at Main TS are at their end of life and need to be replaced. Considering the potential for future high density urban development in the area, the Working Group recommends that Hydro One proceed with planning to replace the existing transformers with 60/100 MVA transformers.

Continue planning for replacement of C5E/C7E underground transmission cables

When this regional plan was initiated, Hydro One was well into developing options to replace the existing C5E/C7E underground 115 kV cables running between Terauley TS and Esplanade TS in the downtown core. The Working Group recommends that Hydro One continue planning to replace the existing 115 kV cables.

Continue planning to determine end of life approaches for Manby TS, John TS, and Bermondsey TS

Manby TS and John TS: Planning for replacement of these critical electricity assets is a major undertaking that must consider a variety of factors and requires regional coordination. The Working Group recommends that detailed planning for the end of life of these assets continue, starting with the RIP.

Bermondsey TS: The Working Group recommends that the plan to replace the two end of life transformers at Bermondsey TS be completed within the scope of the RIP.

Gather information to inform future capacity planning for Basin TS

Since there is currently insufficient information to characterize the needs at Basin TS and inform specific recommendations in this IRRP, the Working Group proposes that any recommendation on potential solutions be deferred until the next cycle of regional planning, or earlier, as required.

Specifically, the Working Group recommends that Toronto Hydro coordinate continued planning activities related to defining the nature, scope and timing of the future capacity need at Basin TS, and assessment of possible wires and non-wires solutions to address the need. It is expected that this work will involve engaging with key stakeholders, including the City of Toronto and entities responsible for development in the Basin TS area.

If better information about the timing and nature of power system needs in the area indicates there is an urgent need, then Toronto Hydro will inform the Working Group of the need to initiate the next regional planning cycle early.

Proceed with reinforcement of the Richview TS to Manby TS 230 kV corridor

This IRRP re-affirms the need for the Richview TS to Manby TS 230 kV corridor reinforcement that was recommended in the previous regional planning cycle. The Working Group therefore recommends that Hydro One proceed with the reinforcement of the Richview TS to Manby TS 230 kV corridor and begin community engagement, as well as initiate the EA to ensure that the reinforced corridor is in-service as soon as possible.

Keep options available to address long term regional supply capacity needs

The IESO will monitor peak demand annually, along with achievement of energy efficiency and DER uptake, with a particular focus on the areas with forecasted capacity needs. This information will be used to determine when decisions on the long term plan are required, and to inform the next cycle of regional planning for the area. This work will include detailed planning and community engagement to define the needs and associated timing in a manner that will permit the evaluation of possible NWAs as solutions.

The Working Group therefore recommends that the IESO coordinate continued planning work and engagement with stakeholders and the community to define and communicate, as soon as practicable, the longer-term capacity needs; identify opportunities for a range of cost-effective solutions, including DERs and energy efficiency; and identify potential wires solutions and avoidable costs should these needs be deferred through NWAs. The information and insights developed through these activities will be used to inform the next regional planning cycle.

7.5.1 Implementation of Recommended Plan

To ensure that the near term electricity needs of the Toronto region are addressed, plan recommendations will need to be implemented as soon as possible. Specific actions and deliverables are outlined in Table 7-4, along with the recommended timing.

Table 7-4: Summary of Needs and Recommended Actions in Toronto Region

Need	Recommended Action(s)/Deliverable(s)	Lead Responsibility	Time frame/ Need Date
End-of-life of overhead line sections H1L / H3L / H6LC / H8LC and L9C / L12C	Proceed with replacement as needed to meet identified timelines	Hydro One	2022-2033 for HxL/HxLC circuits; 2023-2024 for LxC circuits
End-of-life of Main TS transformers, 115 kV disconnect switches and 115 kV current voltage transformers	Proceed with replacement as needed to meet identified timelines	Hydro One	2021-2022
End-of-life of C5E / C7E underground transmission cables	Continue with EA, and proceed with replacement to meet identified timelines	Hydro One	2024-2025
End-of-life assets at Manby TS, John TS and Bermondsey TS	Continue with detailed planning to make a decision in time to address the need; initiate in the Regional Infrastructure Plan	Working Group	2025-2027
Capacity to supply projected load at Manby TS	Continue with implementation of Horner TS expansion to provide relief	Hydro One	2021
Capacity to supply projected load at Basin TS	Continue to gather information to inform assessment of future need and timing; engage with key stakeholders; trigger regional planning if necessary	Toronto Hydro	2019 to next planning cycle
Richview to Manby TS 230 kV reinforcement	Initiate EA work, community engagement, and OEB Section 92 Application	Hydro One	2021 or as soon as possible

Need	Recommended Action(s)/Deliverable(s)	Lead Responsibility	Time frame/ Need Date
Leaside TS and Manby TS autotransformer capacity; Manby TS to Riverside Junction; and Bayview Junction to Balfour Junction	Further define characteristics of longer-term needs; define information needed from local stakeholders; identify DER and energy efficiency potential; develop wires-based alternatives; assess and compare wires and NWAs	IESO	2019 to next planning cycle

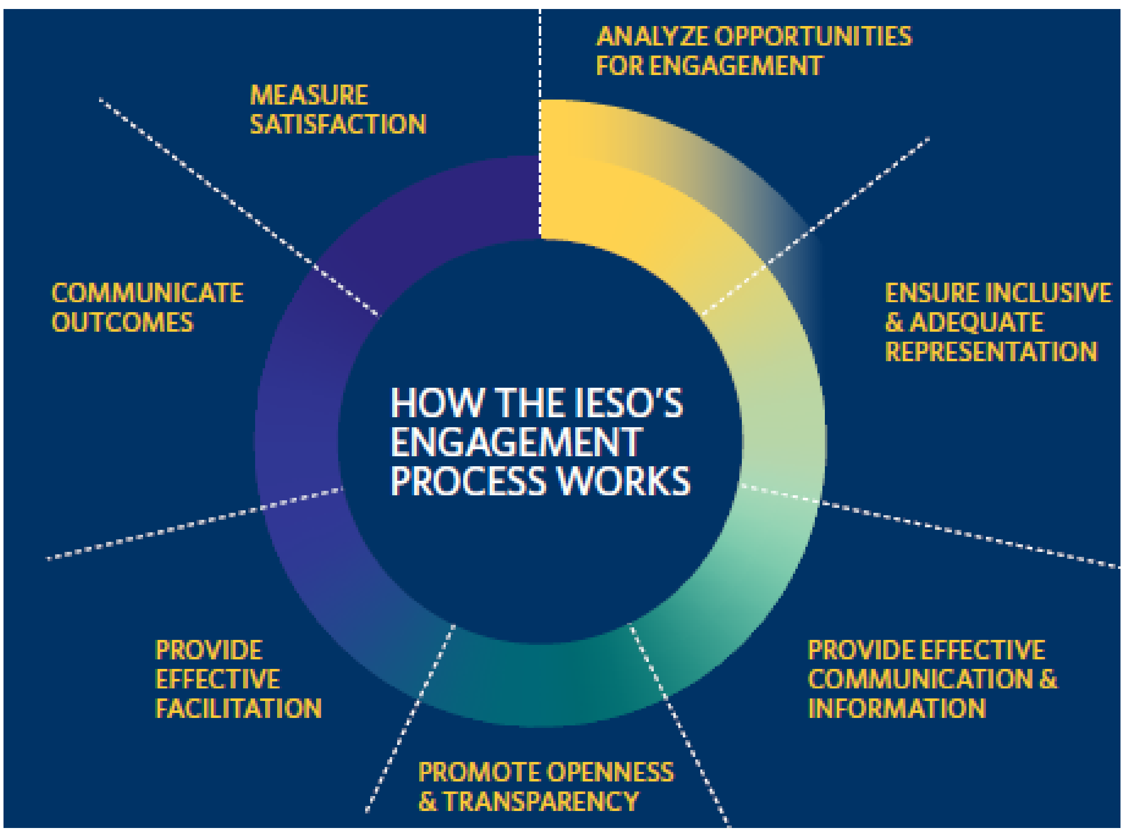
8. Community and Stakeholder Engagement

Community engagement is an integral component of the regional planning process. Providing opportunities for input in regional planning enables the views and preferences of the community to be considered in the development of an IRRP and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken for the Toronto IRRP.

8.1 Engagement Principles

The IESO's Engagement Principles[23] guided the process to help ensure that all interested parties were aware of and could contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, and to support its efforts to build trusted relationships.

Figure 9-1: IESO Engagement Principles



[23] http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Overview/Engagement-Principles

8.2 Creating an Engagement Approach

The outreach and engagement approach was designed to ensure the IRRP reflected input from key community and stakeholder representatives. A dedicated engagement web page[24] was also created to provide openness and transparency throughout the engagement process. This web page hosted all engagement activities, including background information, presentations and public meetings/webinars on the development of this IRRP, as well as previous plans for the area.

The IESO's email subscription service for the Toronto planning region was used to send information to interested communities and stakeholders who subscribed to receive updates. Targeted outreach to municipalities, Indigenous communities and other business sectors in the region was also conducted at the outset of this engagement and continued throughout the planning process.

In addition, regular communications were sent via the IESO's weekly Bulletin, which has subscribers from across Ontario's electricity sector.

8.3 Engage Early and Often

Leveraging relationships built during the previous planning cycle, the IESO held preliminary discussions to help inform the engagement approach during this second planning cycle – starting with the Scoping Assessment Outcome Report.

Early communication and engagement activities for the Toronto IRRP began with invitations to all subscribers and targeted communities to learn about and provide comments on the draft Toronto Region Scoping Assessment Outcome Report before it was finalized in February 2018. This scoping assessment identified the need for an IRRP for the Toronto region and included terms of reference to guide development of the plan. Following feedback, and the IESO's response to feedback – both of which are posted on the engagement web page – the final Scoping Assessment Outcome Report was also published.

Outreach then began with targeted communities to inform early discussions for the development of the IRRP. The launch of a broader engagement initiative followed with an

[24] http://ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Integrated-Regional-Resource-Plan-Toronto

invitation to subscribers to ensure that all interested parties were made aware of this opportunity for input.

A public engagement meeting, held to give interested parties an opportunity to learn about the draft IRRP and provide comments, attracted a cross-representation of stakeholder and community representatives. Following a 14-day comment period, no further comments were received for consideration during the development of the IRRP.

As a final step in this engagement, all participating parties were invited to comment on the proposed recommendations in this IRRP. Comments received during the engagement meeting and in response to the proposed recommendations related to six major themes:

1. Non-wires alternatives
2. Considerations to inform future electricity needs in electricity system planning
3. Electrification (e.g., electric vehicles)
4. Costs of the electricity system
5. Composition of the technical working group
6. Engagement/education

Based on this feedback, it is clear that there is a strong need for ongoing monitoring of capacity and local demand growth, as well as continued discussion and engagement with communities and stakeholders. While needs do not start to emerge until the 2030s or later, the IESO recognizes the importance of sustained dialogue to ensure alignment with local priorities, initiatives and developments. The full submissions can be found on the IESO's website. Reponses to specific feedback are provided as Appendix G: Responses to Public Feedback on Proposed Recommendations.

All background information, including engagement presentations and recorded webinars, are available on the IESO's Integrated Regional Resource Plan engagement web page.

8.4 Outreach with Municipalities

As the City of Toronto was a key stakeholder in the development of this IRRP, the IESO held a number of meetings with city representatives to seek input on municipal planning and to ensure that the city's plans were taken into consideration. Meetings began in June 2018 at the outset of these discussions and continued in April and May 2019. These meetings helped to inform the city's electricity needs and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

9. Conclusion

This report documents an IRRP that has been developed for the Toronto region, and identifies regional electricity needs and opportunities to preserve or enhance electricity system reliability in Toronto from 2019 to 2040. The IRRP makes recommendations to address near term issues, and lays out actions to monitor, defer, and address long term needs.

To further review "wires" solutions that address end of life asset replacement and other transmission supply needs, the Working Group recommends that Hydro One initiate an RIP. The IESO will continue to provide input and support throughout the RIP process, and assist with any regulatory matters arising during plan implementation.

To support the development of the plan, this IRRP includes recommendations with respect to developing alternatives, monitoring load growth and efficiency achievements, and evaluating DER potential and value in the region. Responsibility for these actions has been assigned to the appropriate members of the Working Group. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the regional plan for the Toronto region.

The Toronto region Working Group will continue to meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

Toronto Hydro-Electric System Limited
EB-2023-0195
Exhibit 2B
Section B0
Appendix E
ORIGINAL
(30 pages)

Toronto Region Scoping Assessment Outcome Report

March 21, 2023

Connecting Today.
Powering Tomorrow.

Table of Contents

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's regional planning process, as defined through the Transmission System Code, Distribution System Code, and IESO license.

This is the third cycle of regional planning for the Toronto region, and it was initiated in fall 2022. Information and links to earlier products are available on the IESO webpage, here. The Needs Assessment is the first step in the regional planning process and was carried out by the Technical Working Group (TWG) led by Hydro One. The Needs Assessment Report was finalized on December 19, 2022 and identified some needs that may require further regional coordination. This need information was an input into the Scoping Assessment. The Technical Working Group reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach. It also considered past or ongoing initiatives in the region, including the recent Pathways to Decarbonization report.

The Scoping Assessment considers three potential planning approaches for the region (or sub-regions, if applicable), including: an IRRP – where both wires and non-wires options have potential to address needs; a Regional Infrastructure Plan (RIP) – which considers wires-only options; or a local plan undertaken by the transmitter and affected local distribution company – where no further regional coordination is needed.

This Scoping Assessment report:

- Lists the needs requiring more comprehensive planning, as identified in the Needs Assessment report;
- Reassesses the areas that need to be studied and the geographic grouping of the needs (if required);
- Considers impacts on planning assumptions and potential outcomes on needs resulting from local and provincial policy goals;
- Determines the appropriate regional planning approach and scope where a need for regional coordination or more comprehensive planning is identified;
- Establishes a terms of reference for an IRRP, if an IRRP is required; and
- Establishes the composition of the IRRP Technical Working Group.

2. Technical Working Group

The Scoping Assessment was carried out with the following participants:

- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Transmission)
- Toronto Hydro Electric Systems Limited (Toronto Hydro)
- Alectra Utilities Corporation
- Elexicon Energy Inc.
- Hydro One Networks Inc. (Distribution)

3. Categories of Needs, Analysis and Results

3.1 Overview of the Toronto Region

The Toronto electricity planning region includes the area within the municipal boundary of the City of Toronto. The electricity supply to the Toronto Region is shown in Figure 1. The region is supplied by a network of 230 kV lines that run along the northern and western edges of the city, and into the core from the east, providing supply points for step-down stations that supply these areas. The central core of the City of Toronto is supplied by a 115 kV network that connects to the 230 kV system through two 230/115 kV autotransformer stations (Leaside Transformer Station (TS) and Manby TS). A small number of distribution feeders from Toronto also supply customers in the City of Mississauga and City of Pickering.

In addition to the transmission infrastructure described above, the Portlands Energy Centre (550 megawatt [MW] summer capacity) is a natural gas-fired combined cycle power plant that provides a major source of supply to Toronto. This station is located near the Eastern waterfront and is connected to the Hearn Switching Station (SS) shown in Figure 1.

Numerous distributed energy resource (DER) facilities are located throughout the City. For example, through previous procurements such as the Feed-in Tariff program, Renewable Energy Standard Offer Program, and Combined Heat and Power (CHP) Standard Offer Program, approximately 1,900 individual renewable and CHP facilities have been placed in service in the City of Toronto. The total combined electrical supply capacity of these DERs is 106 MW.[1]

The region is summer peaking and the 2022 peak summertime electricity demand in the Toronto region was approximately 4,400 MW.[2]

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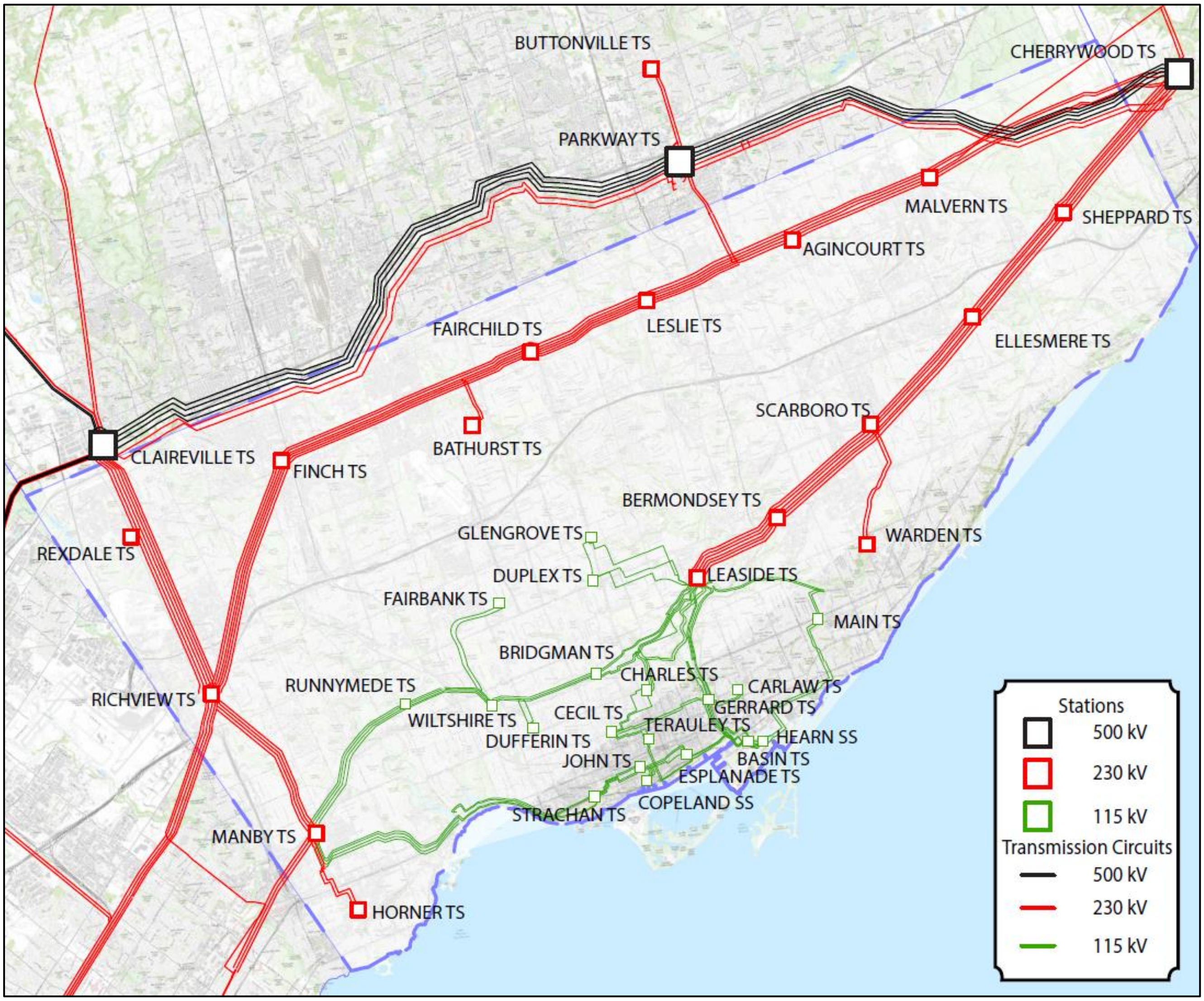
[1] This translates to about 40 MW of "effective" capacity that system planners can count on during the peak demand period (assuming 34% capacity factor for solar PV, 13.6% for wind, and 100% for all other fuel types, including CHP).

[2] The peak electricity demand in summer 2006 was 5,305 MW; in summer 2022, demand was 4,356 MW.

Figure 1 | Electricity Infrastructure of the Toronto Region



3.1.1 Indigenous Communities

Toronto is home to Indigenous peoples from across Canada. Located near Toronto are the Mississaugas of the Credit, Six Nations of the Grand River, the Haudenosaunee Confederacy Chiefs Council (HCCC) and MNO Toronto and the York Region Métis Council. The Huron Wendat of Wendake, Quebec have archaeological resources in southern Ontario, including the Toronto area, due to their historical presence there. The IESO will notify the Mississaugas of the Credit, Six Nations, HCCC, York Region Métis Council and Huron Wendat that regional planning for Toronto is getting underway and invite them to participate in engagement activities.

3.2 Background of the Previous Planning Process

The first cycle of the regional planning process for the Toronto region was formally completed in January 2016 with the publication of Hydro One's Regional Infrastructure Plan (RIP) for the Central Toronto area, following the publication of an IRRP for Central Toronto in April 2015. In February 2017, an update was published to reflect plans to convert commuter heavy rail (Metrolinx - GO) from diesel to electric power.

In mid-2017, Hydro One identified a number of transmission asset renewal needs in Toronto over the next ten years. The scale and timing of these needs necessitated the initiation of another regional planning cycle. Hydro One initiated a Needs Assessment, which officially started the next regional planning cycle for the region. The Needs Assessment was completed in October 2017, and subsequent Scoping Assessment was completed in 2018. An IRRP was initiated in 2018, and released in 2019. This plan focused on transmission asset renewal needs, and preparing to address local and regional capacity needs emerging in the longer term.

The second round of regional planning for the Toronto region was completed in March 2020, with the release of the Hydro One led RIP.

An updated analysis for the Richview to Manby Upgrade project (now known as the "Etobicoke Greenway Project") was conducted in 2021. This analysis reaffirmed the findings in the 2019 IRRP and 2020 RIP and recommended the project go ahead.

3.3 Needs Identified

For this third cycle of regional planning, Hydro One's Needs Assessment provided an update on needs identified in the previous planning cycle and the implementation of projects recommended to address them. It also identified new needs in the Toronto region based on the most up-to-date sustainment plans and a new 10-year demand forecast. A summary of the current projects and plans underway to respond to existing needs, plus the new needs, are outlined below.

3.3.1 Projects and Plans Underway or Complete to Address Previously Identified Needs

The Needs Assessment report lists the needs identified from the previous planning cycle, and provides an update on the status of project implementation for the options recommended to address them (see Table 1). These projects provide a starting point for future assessments and will be accounted for in this planning cycle.

Table 1 | Needs Identified in the Previous Cycle with Implementation Plan Update

Need	Solution and Timing
Copeland TS Phase 2, address capacity need	In-service 2024
Bridgman TS transformer replacement (T11, T12, T13, T14)	Expected completion 2024

Need	Solution and Timing
Fairbank TS transformer replacement (T1, T2, T3, T4)	Expected completion 2024
Main TS transformer replacement (T3, T4)	Expected completion 2024
John TS transformer replacement (T5, T6)	Expected completion 2025
C5E/C7E underground cable replacement between Esplanade TS and Terauley TS	Expected completion 2026
Richview TS to Manby TS 230 kV Corridor Upgrade	Expected completion 2026

Since the previous regional planning cycle, the following additional projects have also been implemented by Hydro One:

- Second DESN at Horner TS, complete 2022
- Refurbishment projects at Runnymede TS (T3, T4), Sheppard TS (T3, T4), and Strachan TS (T12), complete 2021-2022
- Replacement of John TS transformers (T1, T2, T4), complete 2019-2021

3.3.2 Needs Requiring Further Coordination or Study in the Current Planning Cycle

The Needs Assessment then identified new or updated needs in the Toronto region using the 10-year station-level demand forecast provided by the local distribution companies (LDCs), updated asset condition information from Hydro One, as well as the conservation and demand management (CDM) and distributed generation (DG) forecast provided by the IESO. Several of these needs were determined through the Needs Assessment not to require further coordinated study through the regional planning process (see Table 2). However, many may still require a significant amount of planning or have a shared impact with other system assets or needs. For example, any needs dealing with major right of ways, even routine maintenance or like-for-like replacement, may have an impact on shared, downstream, or alternate facilities. Stepdown station asset renewal needs can also be linked to broader needs, if the station is located within a rapidly growing or supply constrained area. These types of needs do not require coordinated study through an IRRP, but should still be considered in scope of further regional planning activities to ensure that outage schedules and other shared impacts are appropriately accounted for.

Table 2 | Needs Determined in the Needs Assessment to not Require Further Coordinated Planning

Need #	Station/Circuit	Description of Need
1	Richview TS to Manby TS 230 kV Corridor[3]	• Line Capacity Need
2	Manby TS, autotransformers (T7, T9, T12)[4] and step-down transformers (T13/T14)	• Asset renewal need
3	115 kV H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. overhead section	• Asset renewal need
4	115 kV L9C/L12C: Leaside TS to Balfour Jct. overhead section	• Asset renewal need
5	Strachan TS: T14 & T13/T15	• Asset renewal need
6	Charles TS: T3/T4	• Asset renewal need
7	Duplex TS: T1/T2 & T3/T4	• Asset renewal need
8	Basin TS: T3/T5	• Asset renewal need
9	Scarboro TS: T23	• Asset renewal need
10	Fairchild TS: T1 & T3/T4	• Asset renewal need
11	Bermondsey TS: T3/T4	• Asset renewal need
12	Malvern TS: T3	• Asset renewal need
13	Fairbank TS	• Station Capacity Need
14	Strachan TS	• Station Capacity Need

[3] Further regional planning is not required as the project was recommended in the previous cycle of regional planning. Hydro One is developing the project, with an expected in-service date of mid-2026.
[4] Hydro One will proceed with development work for replacing autotransformers. However, the overall need for transformation capacity in Toronto as a whole will be assessed in the upcoming IRRP.

The remaining needs, which were determined through the Needs Assessment to require further coordinated study are listed in Table 3. Most needs deal directly with capacity constraints, or load restoration, as a range of solutions may be considered and the impact on broader system operation would need to be evaluated. Note that some step down station capacity needs (Fairbank TS and Strachan TS) were not included in this list, as solutions to address needs have already been identified.

Table 3 | Needs identified in the Needs Assessment as Requiring Further Study

Need #	Station/Circuit	Description of Need
1	115 kV Manby TS to Riverside Jct. Corridor	• Line capacity need
2	230 kV Parkway TS to Richview TS Corridor	• Line capacity need
3	115kV Leaside TS to Wiltshire TS Corridor	• Line capacity need
4	230/115kV Manby W Autotransformers[5]	• Autotransformer capacity need
5	230/115kV Leaside TS Autotransformers	• Autotransformer capacity need
6	Sheppard TS	• Station capacity need
7	Basin TS	• Station capacity need
8	Glengrove TS	• Station capacity need
9	Finch TS / Bathurst TS	• Station capacity need
10	Warden TS	• Station capacity need
11	Loss of C14L/C17L	• Load restoration need
12	Loss of C18R/P22R	• Load restoration need

[5] Hydro One will proceed with development work for replacing autotransformers. However, the overall need for transformation capacity will be looked at in the upcoming IRRP.

3.3.3 Analysis of Needs and Identification of Region

The Technical Working Group (TWG) has discussed the needs in the Toronto region and potential planning approaches to address them. The preferred planning approach is generally informed by:

- Timing of the need, including lead time to develop solutions
- The potential linkages between needs and their required coordination, particularly if across overlapping LDC territories or planning regions
- The opportunity for public engagement to inform outcomes
- The potential for exploring multiple types of options to meet the needs (including non-wires alternatives)
- The potential for regional changes having implications on the upstream bulk power system

In general, the more complex a series of needs are and the greater the need for coordination and engagement, the more likely an IRRP will be selected. If needs have few available solutions, are relatively straight forward, and can be implemented without affecting neighbouring areas or the bulk power system, then a more streamlined planning approach with a narrower scope may be appropriate.

The participants agreed that for each of the identified needs requiring further study, a range of alternatives including wires and non-wires solutions should be assessed. Additionally, several needs were identified which do not require further coordinated planning, but should still be considered in scope of further study as the implementation and timing of solutions have the potential to affect other needs in the area. These include needs whose previously recommended solutions are already underway, and asset renewal needs with the potential to affect overall capacity needs in the area.

Based on discussions, it was agreed that an IRRP should be undertaken to further assess these needs. The scope of an IRRP includes an assessment of CDM, DERs, and other community-based solutions. A Draft Terms of Reference for the IRRP is attached in Appendix B.

The participants also agreed, for the purpose of the next regional plan, that the City of Toronto should not be divided into sub-regions. While most of the needs identified impact electricity infrastructure in the downtown area, some needs have been identified in other parts of Toronto, outside of the central part of Toronto.

Lastly, because none of the needs identified directly impact facilities that supply customers of Alectra Utilities Corporation, Elexicon Energy Inc., or Hydro One Distribution, it was agreed that the core Working Group for the IRRP will include the IESO, Toronto Hydro, and Hydro One Transmission. The other utilities will be informed and invited to participate if any needs, or proposed solutions, may affect their facilities or customers.

3.3.4 Additional Considerations Associated with Growth and Electrification Targets

The City of Toronto has identified certain areas of the city that will undergo further development and growth. One of these areas is the Port Lands, located in the southern portion of Toronto at the mouth of the Don River. Together with Waterfront Toronto, the City has plans for the Port Lands to be "home to sustainable new communities that deliver affordable housing and job opportunities, along with renewed connections to the water and natural environment."[6] As such, the currently undeveloped portions of the Port Lands are expected to undergo a significant increase in electricity demand, affecting nearby infrastructure, in particular Basin TS.

Another area of interest is the Downsview area, particularly the area surrounding the Downsview Airport. An update to the secondary plan (known as "Update Downsview") aims to "plan for a new community within the City and reconnect the Downsview lands with the surrounding neighbourhoods" after Bombardier leaves the Downsview Airport by the end of 2023[7]. Update Downsview plans to facilitate new housing, jobs, parks and other community services in the area. This will likely affect the 230 kV stations located in northern Toronto, primarily Bathurst TS and Finch TS and the circuits that supply them.

For the upcoming IRRP, the Toronto Working Group will engage with stakeholders and communities to ensure growth plans in these areas are considered and reflected in the IRRP electricity demand forecast.

3.3.5 Pathways to Decarbonization Report

In December 2022, the IESO published its Pathways to Decarbonization Report. This report was created in response to the Ministry of Energy's request to evaluate a moratorium on new natural gas generating stations in Ontario and to develop an achievable pathway to decarbonization in the electricity system. The report considered the resource and bulk system implications for meeting two time specific scenarios:

- A "2035 Moratorium" scenario, which considers the potential results of a moratorium on natural gas generation in Ontario's electricity sector, with a phase out by 2035, where feasible. This scenario also considered the impact of greater uptake of electrified transportation options, among other electrification objectives
- A "2050 Pathways" scenario, which goes beyond the 2035 Moratorium case to consider the phase out of all GHG emitting generation resources, as well as significant demand growth based on theoretical, aggressive, policy-driven electrification in three major sectors: transportation, building heat and industrial process

In the report, the IESO committed to ensuring "that regional planning processes for Toronto and York Region address the unique challenges for local reliability of phasing out natural gas". Specifically, the Pathways to Decarbonization Report stated:

"The IESO will ensure that future bulk and regional planning activities… …further assess the identified needs and reinforcement options and make recommendations for next steps, including

[6] Waterfront Toronto: https://www.waterfrontoronto.ca/our-projects/scope-scale/port-lands

[7] Update Downsview: https://www.toronto.ca/city-government/planning-development/planning-studies-initiatives/update-downsview/

development work. In particular, upcoming regional planning activities for both Toronto and York Region will need to examine options for the eventual replacement of the local reliability benefits provided by existing gas."

The IESO recognizes the government of Ontario is actively consulting on the Pathways to Decarbonization report. Outcomes of that consultation may inform the IESO's approach to this regional plan. As such, the Terms of Reference for the Toronto IRRP may be amended at a future time to account for additional objectives, activities, and assumptions required to align deliverables with new provincial direction.

3.3.6 GTA Bulk Supply Study

In December 2022, the IESO also published the 2022 Annual Planning Outlook (APO). The APO is an annual report that provides a long-term view of Ontario's electricity system, forecasting system needs and exploring the province's ability to meet them. The 2022 APO identified potential issues in the bulk system (i.e. the system that transfers large amounts of power across the province) due to increasing demand and the planned retirement of the Pickering Nuclear Generating Station and indicated that the IESO would undertake a GTA Bulk Supply Study in 2023. This study will review the capability of the bulk power system to deliver power into the broader GTA load centre. As the GTA Bulk Supply Study will be conducted in parallel with regional planning in Toronto, its findings (i.e. needs and recommended solutions) will be coordinated with the Toronto IRRP, and vice-versa.

4. Conclusion and Next Steps

The Scoping Assessment concludes that:

- Based on the available information, an IRRP is to be undertaken for the Toronto region;
- No sub-regions within Toronto will be created for the IRRP; the region should be treated as a whole for the purpose of developing a comprehensive plan;
- The implementation of recommendations from the previous planning cycle should continue;
- The composition of the IRRP Working Group will include the IESO, Toronto Hydro, and Hydro One Transmission. Other Local Distribution Companies in the region will be informed of any needs or solutions that may affect their facilities or customers;
- Given the significant anticipated scope of the study, the full 18-month timeline for completion of the IRRP is expected to be required;
- In addition to addressing the needs identified in the Needs Assessment, two focus areas will be examined in detail in the IRRP: Port Lands and Downsview;
- The Toronto IRRP will co-ordinate its findings with the GTA Bulk Supply Study, and vice-versa;
- The IESO may amend the Terms of Reference for the Toronto IRRP as required to align with provincial direction following consultation related to the Pathways to Decarbonization Report.

All IRRPs will include opportunities for engagement with local communities and stakeholders, as well as include discussion of any local initiatives focused on energy and/or reducing GHG emissions, and how the IRRP can coordinate with these plans. This could include Community Energy Plans, Net-Zero strategies, or similar. Particular attention will be paid to opportunities for information sharing and/or coordination of goals and outcomes.

The draft Terms of Reference for the Toronto IRRP is attached in Appendix B.

Appendix A – List of Acronyms

Acronym	Definition
APO	Annual Planning Outlook
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DG	Distributed Generation
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station
TWG	Technical Working Group

Appendix B – Toronto Region Integrated Regional Resource Plan (IRRP) Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, roles and responsibilities, deliverables and timelines for an Integrated Regional Resource Plan (IRRP) for the Toronto region.

Based on the power system needs identified throughout the region (including a number of transmission stations and lines requiring replacement based on asset condition assessment in the near term and medium term), strong urban growth and intensification projections in the City of Toronto, expansion of electrified transit, and potential demand and resource pressures from decarbonization policies, an IRRP is the appropriate planning approach for this region.

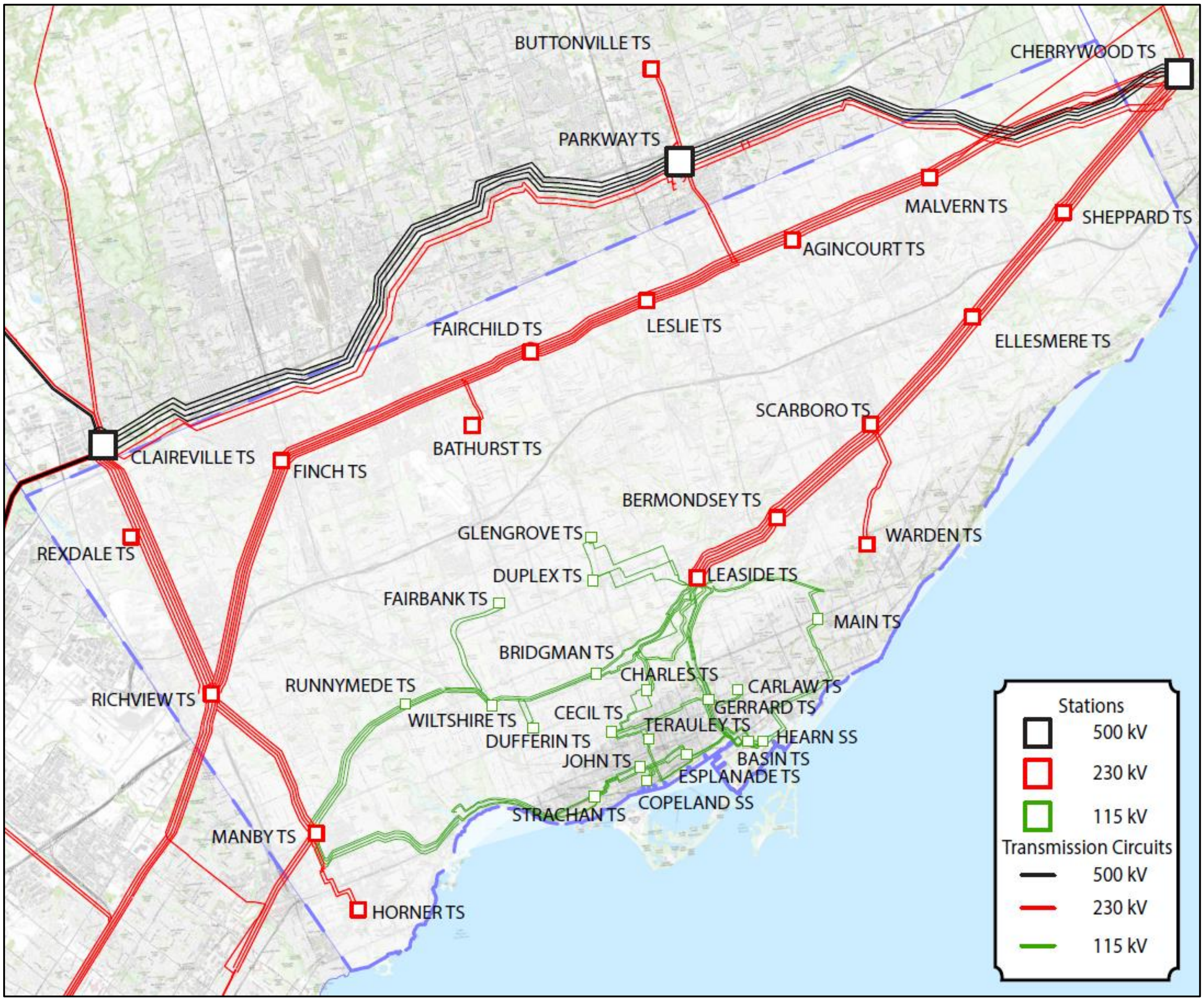
1.1 The Toronto Region

The Toronto electricity planning region includes the area within the municipal boundary of the City of Toronto. The electricity supply to the Toronto Region is shown in Figure 2. The region is supplied by a network of 230 kV lines that run along the northern and western edges of the city, and into the core from the east, providing supply points for step-down stations that supply these areas. The central core of the City of Toronto is supplied by a 115 kV network that connects to the 230 kV system through two 230/115 kV autotransformer stations (Leaside Transformer Station (TS) and Manby TS). A small number of distribution feeders from Toronto also supply customers in the City of Mississauga and City of Pickering.

Toronto is home to Indigenous peoples from across Canada. Located near Toronto are the Mississaugas of the Credit, Six Nations of the Grand River, the Haudenosaunee Confederacy Chiefs Council and MNO Toronto and the York Region Métis Council. The Huron Wendat of Wendake, Quebec have archaeological resources in southern Ontario, including the Toronto area, due to their historical presence there. The IESO will notify the Mississaugas of the Credit, Six Nations, HCCC, York Region Métis Council and Huron Wendat that regional planning for Toronto is getting underway and invite them to participate in engagement activities.

For the purpose of this IRRP, no divisions are proposed that would create any sub-regions to assess within the City of Toronto.

Figure 2 | Electricity Infrastructure of the Toronto Region



1.2 Background

In December 2022, Hydro One completed the Needs Assessment report for the Toronto region. Several needs were identified, and a Scoping Assessment was subsequently commenced to determine the preferred planning approach. An IRRP is ultimately recommended on the basis of the scale of load growth anticipated, potential for diverse types of solution (including wires and non wires), and long term uncertainty associated with city development plans and the potential impact of municipal, provincial, and federal decarbonization and electrification policies.

2. Objectives

1. Assess the adequacy and reliability of the portion of the IESO-controlled grid[8] that provides electricity supply to the Toronto region over the next 25 years.[9]
2. Account for major asset renewal needs, capacity needs, enhancing reliability and resilience, uncertainty in the outlook for electricity demand, and local priorities in developing a comprehensive plan.
3. Consider potential impacts of electrification targets and other policy decisions on needs identified and recommended outcomes, consistent with provincial direction.
4. Evaluate opportunities for cost effective non-wires alternatives, including conservation and demand management (CDM) and distributed energy resources (DER), as well as wires approaches for addressing the needs identified.
5. Develop an implementation plan that maintains flexibility in order to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for medium-term needs, and planning direction for the long-term.

3. Scope

3.1 Needs to be Addressed

The IRRP will develop and recommend an integrated plan to meet the needs of the Toronto region. The plan is a joint initiative involving Toronto Hydro, Hydro One Transmission, and the IESO,[10] and will account for input from the community through engagement activities. The plan will integrate the electricity demand outlook scenarios, CDM, DER uptake, transmission and distribution system capabilities, and align with relevant community plans, bulk system developments, and policy direction as applicable.

The scope of the Toronto IRRP includes the following needs, as identified in the Needs Assessment:

Table 4 | Needs Identified in the Needs Assessment as Requiring Further Study

Facilities	Type of Need	Expected Timing
115 kV Manby TS to Riverside Jct. Corridor	Line capacity need	2028
230 kV Parkway TS to Richview TS Corridor	Line capacity need	Beyond 2031
115kV Leaside TS to Wiltshire TS Corridor	Line capacity need	Beyond 2031
230/115kV Manby W Autotransformers	Autotransformer capacity need	Beyond 2031

[8] The scope of the assessment includes transmission stations.

[9] The typical planning horizon in a regional study is 20 years; however, Toronto Hydro produces a long-range forecast spanning 25 years and this forecast will be used as the basis for assessing long-term system needs in the IRRP.

[10] Alectra Utilities, Elexicon Energy Inc. and Hydro One Distribution are also supplied by feeders from Toronto. These utilities will not form part of the core Technical Working Group. However, they will be informed of any developments that may impact their facilities and/or customers.

Facilities	Type of Need	Expected Timing
230/115kV Leaside TS Autotransformers	Autotransformer capacity need	Beyond 2031
Sheppard TS	Station capacity need	Beyond 2031
Basin TS	Station capacity need	Beyond 2031
Glengrove TS	Station capacity need	Beyond 2031
Finch TS / Bathurst TS	Station capacity need	Beyond 2031
Warden TS	Station capacity need	Beyond 2031
Loss of C14L/C17L	Load restoration need	2031
Loss of C18R/P22R	Load restoration need	2031

Other identified needs in the Needs Assessment not listed in Table 4 above will proceed with Local Planning or Regional Infrastructure Planning as appropriate. Hydro One will keep the Working Group informed on project development.

3.2 Additional Considerations Associated with Growth and Electrification Targets

The City of Toronto has identified certain areas of the city that will undergo further development and growth. One of these areas is the Port Lands, located in the southern portion of Toronto at the mouth of the Don River. Together with Waterfront Toronto, the City has plans for the Port Lands to be "home to sustainable new communities that deliver affordable housing and job opportunities, along with renewed connections to the water and natural environment."[11] As such, the currently undeveloped portions of the Port Lands are expected to undergo a significant increase in electricity demand, affecting nearby infrastructure, in particular Basin TS.

Another area of interest is the Downsview area, particularly the area surrounding the Downsview Airport. An update to the secondary plan (known as "Update Downsview") aims to "plan for a new community within the City and reconnect the Downsview lands with the surrounding neighbourhoods" after Bombardier leaves the Downsview Airport by the end of 2023[12]. Update Downsview plans to facilitate new housing, jobs, parks and other community services in the area. This will likely affect the 230 kV stations located in northern Toronto, primarily Bathurst TS and Finch TS and the circuits that supply them.

For the upcoming IRRP, the Toronto Working Group will engage with stakeholders and communities to ensure growth plans in these areas are considered and reflected in the IRRP electricity demand forecast.

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[11] Waterfront Toronto: https://www.waterfrontoronto.ca/our-projects/scope-scale/port-lands

[12] Update Downsview: https://www.toronto.ca/city-government/planning-development/planning-studies-initiatives/update-downsview/

3.3 Pathways to Decarbonization Report

In December 2022, the IESO published its Pathways to Decarbonization Report. This report was created in response to the Ministry of Energy's request to evaluate a moratorium on new natural gas generating stations in Ontario and to develop an achievable pathway to decarbonization in the electricity system. The report considered the resource and bulk system implications for meeting two time specific scenarios:

- A "2035 Moratorium" scenario, which considers the potential results of a moratorium on natural gas generation in Ontario's electricity sector, with a phase out by 2035, where feasible. This scenario also considered the impact of greater uptake of electrified transportation options, among other electrification objectives
- A "2050 Pathways" scenario, which goes beyond the 2035 Moratorium case to consider the phase out of all GHG emitting generation resources, as well as significant demand growth based on theoretical, aggressive, policy-driven electrification in three major sectors: transportation, building heat and industrial process

In the report, the IESO committed to ensuring "that regional planning processes for Toronto and York Region address the unique challenges for local reliability of phasing out natural gas". Specifically, the Pathways to Decarbonization Report stated:

"The IESO will ensure that future bulk and regional planning activities… …further assess the identified needs and reinforcement options and make recommendations for next steps, including development work. In particular, upcoming regional planning activities for both Toronto and York Region will need to examine options for the eventual replacement of the local reliability benefits provided by existing gas."

The IESO recognizes the government of Ontario is actively consulting on the Pathways to Decarbonization report. Outcomes of that consultation may inform the IESO's approach to this regional plan. As such, this Terms of Reference may be amended at a future time to account for additional objectives, activities, and assumptions required to align the Toronto IRRP deliverables with new provincial direction.

3.4 GTA Bulk Supply Study

In December 2022, the IESO also published the 2022 Annual Planning Outlook (APO). The APO is an annual report that provides a long-term view of Ontario's electricity system, forecasting system needs and exploring the province's ability to meet them. The 2022 APO identified potential issues in the bulk system (i.e. the system that transfers large amounts of power across the province) due to increasing demand and the planned retirement of the Pickering Nuclear Generating Station and indicated that the IESO would undertake a GTA Bulk Supply Study in 2023. This study will review the capability of the bulk power system to deliver power into the broader GTA load centre. As the GTA Bulk Supply Study will be conducted in parallel with regional planning in Toronto, its findings (i.e. needs and recommended solutions) will be coordinated with the Toronto IRRP, and vice-versa.

4. Activities

The IRRP process will consist of the activities as listed below. The activities and anticipated timelines are summarized in Table 5 at the end of this document. The first major planning activity following preparation of this Terms of Reference is the development of the electricity demand forecast to serve as the basis for conducting system assessments. The timing for initiating the assessment (Activity 3) and all subsequent plan development activities will be contingent on the Working Group agreeing on the demand forecast to be used.

1) Develop an electricity demand forecast for the Toronto region. This may be comprised of a number of electricity demand scenarios that account for uncertain elements that can affect (e.g., raise or lower) the need for electricity in the region:
2) Confirm baseline technical assumptions including infrastructure ratings, system topology and relevant base cases for simulating the performance of the electric power system. Collect information on:
    a. Transformer, line and cable continuous ratings, long-term and short-term emergency ratings;
    b. Known reliability issues and load transfer capabilities;
    c. Customer load breakdown by transformer station;
    d. Historical and present CDM peak demand savings and installed/effective DER capacity, by transformer station.
3) Perform assessments of the capacity, reliability and security of the electric power system under each demand outlook scenario.
    a. Confirm and/or refine the needs listed earlier in this section using the demand outlook; establish the sensitivity of each need to different demand outlook scenarios.
    b. Identify additional infrastructure capacity needs and any additional load restoration needs; if new needs are discovered, determine the appropriate planning approach for addressing them.
4) Identify options for addressing the needs, including, non-wires and wires alternatives. Where necessary, develop portfolios of solutions comprising a number of options that, when combined, can address a need or multiple needs.
    a. Collect information about the attributes of each option: cost, performance, timing, risk, etc.
    b. Develop cost estimates for all screened-in options as a means of informing further evaluations of alternatives.
    c. Seek cost-effective opportunities to manage growth, by identifying opportunities to reduce electricity demand.
5) Evaluate options using criteria including, but not limited to the areas of: technical feasibility and timing, economics, reliability performance, risk, environmental, regulatory, and social factors. Evaluation criteria will be informed through community engagement activities and reflect attributes deemed important to the community-at-large.
6) Develop recommendations for actions and document them in an implementation plan, to address needs in the near-term and medium-term.

7) Develop a long-term plan for the electricity system in Toronto to address the identified long-term needs, taking into account uncertainty inherent in long-term planning, local and provincial policy goals, commitments, and climate change action plans.
    a. Discuss possible ways the power system in Toronto could evolve to address potential long-term needs, support the achievement of local and provincial long-term policy goals and plans, and support the achievement of the long-term vision for the electricity sector.
    b. During the development of the plan, seek community and stakeholder input to confirm the long-term vision, expected impacts on the electricity system, and inform the recommended actions through engagement.
8) Complete an IRRP report documenting the near-term and medium-term needs, recommendations, and implementation actions; and long-term plan recommendations.

In order to carry out this scope of work, the Working Group will consider the data and assumptions outlined in section 4 below.

5. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
  - Historical coincident and non-coincident peak demand information and trends for the region
  - Historical weather correction, for median and extreme conditions
  - Gross peak demand forecast scenarios by TS, etc.
  - Coincident peak demand data
  - Identified potential future load customers, including transit expansions, electrification of personal vehicles, space heating/cooling, water heating, and other end-uses due to provincial and local GHG emissions reduction policies and targets

- Conservation and Demand Management
  - LDC CDM plans
  - Incorporation of verified LDC results and other CDM programs/opportunities in the area
  - Long-term conservation forecast for LDC customers, based on region's share of the provincial target found in the 2021-2024 CDM Framework
  - Conservation potential studies, if available
  - Potential for CDM at transmission-connected customers' facilities, if applicable
  - Load segmentation data for each TS based on customer type (residential, commercial, institutional, industrial)
  - Local building codes, energy performance requirements, etc.

- Local resources
  - Existing local generation resources, including distributed energy resources (DER), district energy resources, customer-based generation, as applicable
  - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
  - Expected performance/dependability/output of local generation resources coincident with the local peak demand period
  - Future district energy plans, combined heat and power, energy storage, or other generation proposals, including requirements for on-site back-up and emergency generation

- Relevant local and provincial plans and studies, as applicable
  - LDC Distribution System Plans
  - Community Energy Plans and Municipal Energy Plans
  - City policies with an impact on electricity usage, including TransformTO
  - Municipal Growth Plans
  - Future transit plans impacting electricity use, including personal vehicle electrification, transit expansion (e.g. Ontario Line), and transit electrification (e.g. GO train electrification)
  - Pathways to Decarbonization Report

- Criteria, codes and other requirements
  - Ontario Resource and Transmission Assessment Criteria (ORTAC)
    - Supply capability

        - Load security
        - Load restoration requirements
    - NERC Reliability Standards and NPCC Reliability Criteria and Directories, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to transmission delivery points
    - Other applicable requirements, including municipal requirements

- Existing system capability
    - Transmission line ratings as per transmitter records
    - System Limits as modelled, defined and determined by the IESO and incorporated into the IESO Power Flow base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capabilities
    - Technical and operating characteristics of local generation

- Asset renewal considerations/sustainment plans
    - Transmission assets
    - Distribution assets, as applicable

- Other considerations, as applicable

6. Technical Working Group

The IRRP Technical Working Group will consist of planning representatives from the following organizations:

- Independent Electricity System Operator *(Lead for the IRRP)*
- Toronto Hydro Electric System Limited (Toronto Hydro)
- Hydro One Networks Inc. (Transmission)

The following LDCs will not be part of the IRRP Technical Working Group but will be informed of any developments that may impact their facilities and/or customers:

- Alectra Utilities Corporation
- Elexicon Energy Inc.
- Hydro One Networks Inc. (Distribution)

6.1 Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

7. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Technical Working Group is committed to conducting plan-level engagement throughout the development of the Toronto IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 5.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

8. Activities, Timeline, and Primary Accountability

Table 5 | IRRP Timelines & Activities

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	March 2023
2. Develop the planning forecast for the region		Long-term planning forecast scenarios	Q2-Q4 2023
a. Establish historical coincident peak demand information	IESO		
b. Establish historical weather correction, median and extreme conditions	IESO		
c. Establish gross peak demand forecast	Toronto Hydro		
d. Establish existing, committed, and potential DG	IESO, Toronto Hydro		
e. Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	Toronto Hydro/ Hydro One	Load transfer capabilities under normal and emergency conditions	Q1 2024
4. Provide and review relevant community plans, if applicable	Toronto Hydro, communities, stakeholders, and IESO	Relevant community plans	Q1 2024
5. Complete system studies to identify needs over a 20-year time horizon Obtain PSS/E base case Apply reliability criteria as defined in ORTAC and other applicable criteria to demand forecast scenarios Confirm and refine the need(s) and timing/load levels	IESO	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q1-Q2 2024
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q2 2024
a. Conduct a screening to identify which wires and non-wires options warrant further analysis	IESO		
b. Verify the LMC of the system to better determine timing of needs and support options development	IESO		
c. Develop screened-in energy efficiency options	IESO and Toronto Hydro		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
d. Develop screened-in local generation/demand management options	IESO and Toronto Hydro		
e. Develop the screened-in transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and Toronto Hydro		
f. Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and Toronto Hydro		
g. Technical comparison and evaluation	IESO, Hydro One Transmission, and Toronto Hydro		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required IRRP engagement to be launched in Q2-Q3 2023
a. Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	IESO, Hydro One Transmission, and Toronto Hydro		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
b. Develop communications materials	IESO, Hydro One Transmission, and Toronto Hydro		
c. Undertake community and stakeholder engagement	IESO, Hydro One Transmission, and Toronto Hydro		
d. Summarize input and incorporate feedback	IESO, Hydro One Transmission, and Toronto Hydro		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q1-Q2 2024
9. Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties	IESO	IRRP report	September 2024

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Powering Tomorrow.

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NEEDS ASSESSMENT REPORT

GTA North Region

Date: July 14, 2023

Prepared by: GTA North Region Technical Working Group

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the GTA North Region and to recommend which need: a) does not require further regional coordination and b) identify needs requiring further assessment and/or regional coordination. The results reported in this Needs Assessment are based on the input and information provided by the Technical Working Group ("TWG") for this region.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to 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	GTA North Region (the "Region")		
Lead	Hydro One Networks Inc. ("Hydro One")		
Start Date	March 17, 2023	**End Date**	July 14, 2023

1. INTRODUCTION

The second Regional Planning ("RP") cycle for the GTA North Region was completed in October 2020 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the third RP cycle for this Region, which begins with the Needs Assessment ("NA") phase. The purpose of this NA is to:

a) Identify any new needs and reaffirm needs identified in the previous RP cycle; and
b) Recommend which needs:
   i. require further assessment and regional coordination (and hence, proceed to the next phases of RP); and
   ii. do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted Local Distribution Companies ("LDC") to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the RP process, the RP cycle should be triggered at least once every five years. Considering these timelines, the third Regional Planning cycle was triggered in March 2023 for the GTA North Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the GTA North Region NA includes:

a) Reaffirm and update needs/plans identified in the previous RP cycle;
b) Identify any new needs resulting from this assessment.
c) Recommend which need(s) require further assessment and regional coordination in the next phases of the RP cycle; and
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle).

The Technical Working Group ("TWG") 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.

The planning horizon for this NA is 10 years.

4. INPUTS/DATA

The TWG representatives from LDCs, the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the GTA North Region regarding capacity needs, system reliability needs, operational issues, and major high-voltage ("HV") transmission assets requiring replacement over the planning horizon.

The provincial push towards decarbonization as outlined in the IESO's "Pathways to Decarbonization" report published on December 15, 2022, is expected to impact the electricity demand over the longer term. As a result, the electricity demand, and the need for new infrastructure over the longer term could be higher than previously anticipated or as discussed in this report. The impact of decarbonization will be considered during the next phases of this regional planning cycle.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the study period. The assessment methodology includes a review of planning information such as load forecast, conservation, and demand management ("CDM") forecast, available distributed generation ("DG") information, system reliability and operation issues, and major HV transmission assets requiring replacement.

A technical assessment of needs was undertaken based on:

a) Station capacity and transmission adequacy;
b) System reliability and any operational concerns;
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and
d) Sensitivity analysis to capture uncertainty in the load forecast and variability of demand drivers such as electrification.

6. NEEDS

Needs that were identified in the last RP cycle with current need dates are as follows:

- New Markham MTS #5 – need date is 2028
- Uprate 230kV circuits P45/46 from Parkway TS to Markham MTS #4 Jct. – need date is 2028
- New Northern York TS - need date is 2027
- Woodbridge TS: Replace transformer T5 with similar and size equipment as per current standard – need date is 2027
- New Vaughan MTS #5 – need date is 2030
- Claireville TS x Brown Hill TS Transmission circuit capacity need – need date is 2030
- Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, and V71P/V75P – Existing need[1]

New needs identified in this NA are:

- Kleinburg TS 44kV: Load transfer to Northern York TS – need date is 2027
- New Vaughan MTS #6 – need date is 2027
- New Toubner TS (CTS) – need date is 2027
- New Richmond Hill MTS #3 – need date is 2032
- Load Restoration needs for 230kV circuits P45/P46 – need date is 2027

7. RECOMMENDATIONS

The TWG's recommendations are as follows:

a) No further regional coordination is required for the following need and work will be proceeding as planned:
   - Woodbridge TS: Replace transformer T5
   - Toubner TS: Build new station
   - Vaughan MTS #6: Build new station

b) Further assessment and regional coordination is required in the next phases of the RP cycle to review and/or develop a preferred plan for the follow needs:
   - Kleinburg TS 44kV: Load transfer to Northern York TS
   - Markham MTS #5: Build new station
   - 230kV circuit P45/P46: Uprate circuits between Parkway TS and Markham MTS #4 Jct.
   - Northern York TS: Build new station
   - Vaughan MTS #5: Build new station
   - Richmond Hill MTS #3: Build new station
   - Claireville TS x Brown Hill TS Transmission circuit capacity need and load restoration needs
   - Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, P45/P46, and V71P/V75P

1. No action considered was considered necessary in the last regional planning cycle

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List of Tables and Figures

1 INTRODUCTION

The second cycle of the Regional Planning ("RP") process for the GTA North Region was completed in October 2020 with the publication of the Regional Infrastructure Plan ("RIP") report.

This is the third RP cycle for this Region, which begins with the Needs Assessment ("NA") phase. The purpose of this Needs Assessment ("NA") is to identify new needs in the region, reaffirm and update previously identified needs in the last GTA North RP cycle, and recommend which needs require further assessment and regional coordination.

This report was prepared by the GTA North Region Technical Working Group ("TWG"), led by Hydro One Networks Inc. Participants of the TWG are listed below in Table 1. The report presents the results of the assessment based on information provided by Hydro One, the Local Distribution Companies ("LDCs") and the Independent Electricity System Operator ("IESO").

Table 1-1: GTA North Region TWG Participants

Company
Alectra Utilities Corporation
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator ("IESO")
Newmarket-Tay Power Distribution Ltd
Toronto Hydro-Electric System Limited ("THESL")
Hydro One Networks Inc. (Lead Transmitter)

2 REGIONAL ISSUE/TRIGGER

In accordance with the RP process, the RP cycle should be triggered at least once every five years. Considering these timelines, the third RP cycle was triggered for the GTA North Region.

3 SCOPE OF NEEDS ASSESSMENT

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

- Reaffirm and update needs/plans identified in the previous RP cycle.
- Identify any new needs resulting from this assessment.
- Recommend which need(s) require further assessment and regional coordination in the next phases of the RP cycle; and
- Recommend which need(s) that do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle).

The TWG may identify additional needs during the next phases of the RP process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), and/or RIP based on updated information available at that time.

4 Regional Description and Connection Configuration

The GTA North Region is comprised of the Northern York Area, Southern York Area, and the Western Area. Electrical supply to the region is provided from sixteen 230kV step-down transformer stations. The 2022 Summer Peak area load of the region was approximately 2249MW. Please refer to Figure 4-1.

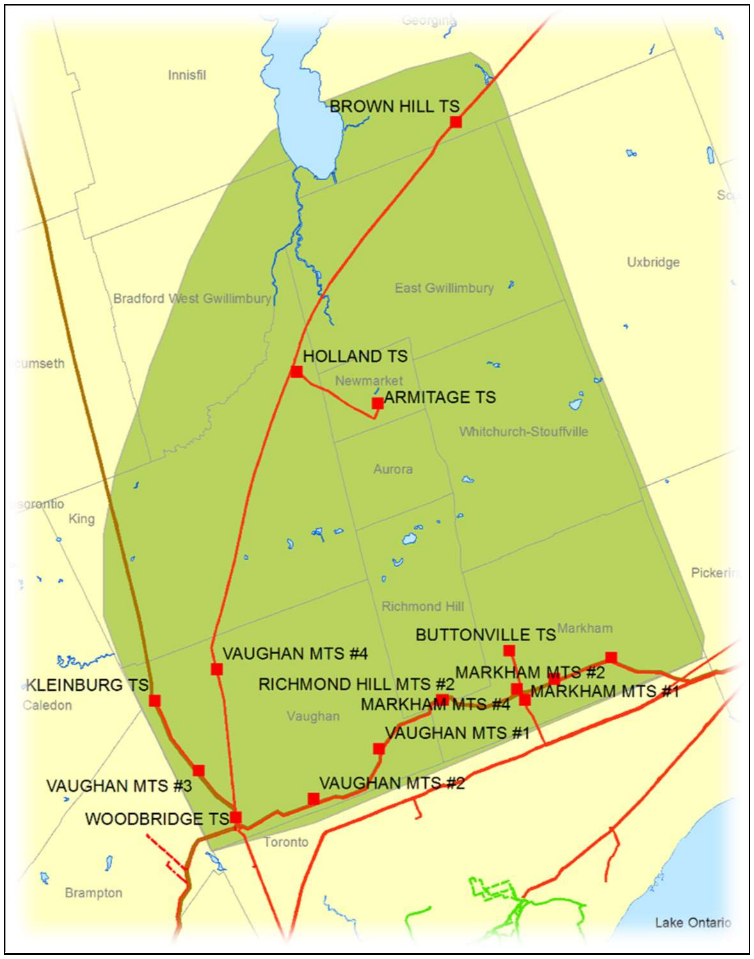


Figure 4-1: GTA North Region Map

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 B88H/B89H in King Township. Please refer to Figure 4-2.

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 Alectra.

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 LDC owned stations and one Hydro One owned) 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 Alectra.

The Western Area comprises the Western portion of the municipality of Vaughan. Electrical supply to the area 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 LDC owned transformer station) stepping down the voltage to 44 kV and 27.6 kV. The LDCs directly supplied are Alectra and Hydro One Distribution. Embedded LDCs include Alectra and Toronto Hydro.

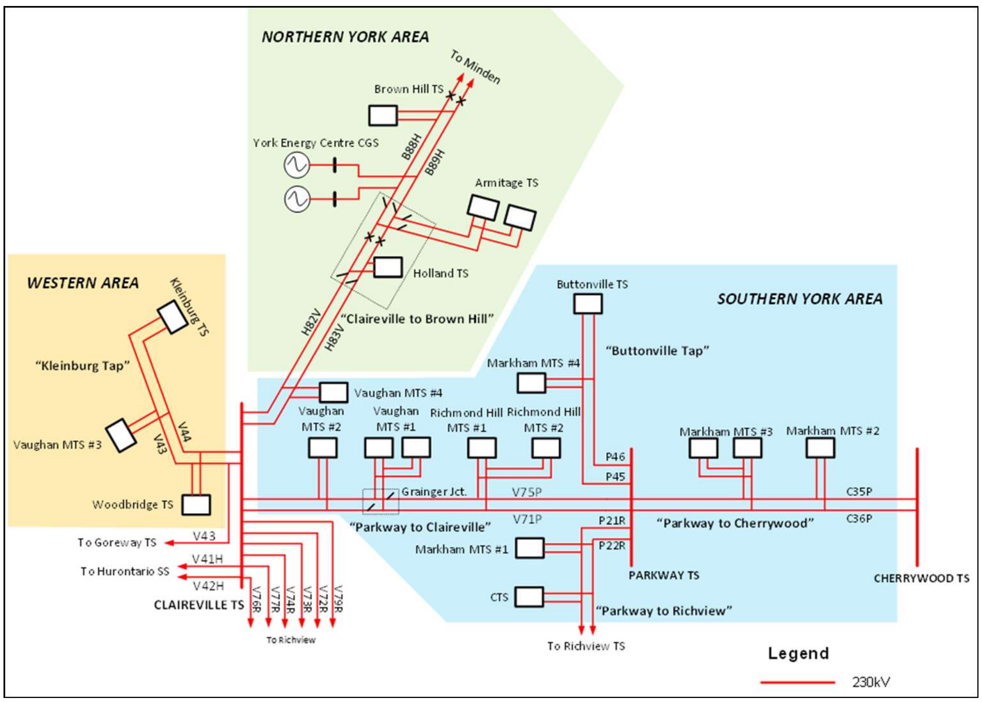


Figure 4-2: GTA North Region– Single Line Diagram

The transformer stations and circuits in the area are listed in Appendix A and Appendix B.

5 INPUTS AND DATA

TWG 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 for all supply stations in the GTA North Region.
- Known capacity and system reliability needs, operational issues, and/or major HV transmission equipment requiring replacement over the study period; and
- Planned/foreseen transmission and distribution investments that are relevant to the GTA North RP process.

In December 2022, the IESO published a report [1] on developing an achievable pathway to the decarbonization of the electricity system. As a result, the electricity demand, and the need for new infrastructure over the longer term could be higher than anticipated or discussed in this report. The impact of the decarbonization and resulting electrification will be considered during the next phase of this regional planning cycle.

6 ASSESSMENT METHODOLOGY

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

- Load forecast: The LDCs provided their load forecast for all the stations supplying their loads in the GTA North Region for the 10-year study period. The IESO provided a Conservation and Demand Management ("CDM") forecast and Distributed Generation ("DG") contract information for the Toronto Region. The region's extreme summer non-coincident peak gross load forecast for each station was prepared by applying the growth rates from the LDC load forecast to the actual 2022 summer peak extreme weather corrected loads. The extreme summer weather correction factor was provided by Hydro One. The net extreme weather summer load forecast was produced by reducing the gross load forecast for each station by the percentage CDM from the IESO for that station. The extreme summer weather corrected net non-coincident peak for the individual stations in the GTA North Region are given in Appendix C.
- Relevant information regarding system reliability and operational issues in the region;
- List of major HV transmission equipment planned and/or identified to be replaced based on asset condition assessment, and relevant for RP purposes. The scope of equipment considered is given in Section 7.1.

A technical assessment of needs was undertaken based on:

- Station capacity and transmission adequacy assessment.
- System reliability and operational considerations.

[1] IESO Report, "Pathways-to-Decarbonization", Dec15, 2022

- Asset renewal for major HV transmission equipment requiring replacement with consideration to "right-sizing"; and
- Sensitivity analysis to capture uncertainty in the load forecast

The following other assumptions are made in this report.

- The study period for this NA is 2023-2032.
- Coincident loads have been assumed equal to non-coincident loads for the purpose of transmission line adequacy assessment.
- 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 (LV) capacitor banks and 95% lagging power factor for stations having LV capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

7 ADEQUACY OF EXISTING FACILITIES

This section provides a review of the adequacy of the transmission lines and stations in the GTA North Region. The adequacy is assessed using the latest extreme weather peak summer regional load forecast provided in Appendix C.

7.1 Adequacy of Northern and Southern York Area Facilities

7.1.1 500 and 230 kV Transmission Facilities

All 500 and most 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 Northern and Southern York Areas are comprised of the following 230 kV circuits. Refer to Figure 4-2.

Northern York Area:

- Claireville TS to Holland TS 230 kV circuits: H82V and H83V.
- Holland TS to Brown Hill TS 230 kV circuits: B88H and B89H.

Southern York Area:

- Parkway TS to Cherrywood TS 230 kV circuits: C35P and C36P.
- Parkway TS to Claireville TS 230 kV circuits: V71P and V75P.
- Parkway TS to Buttonville TS ("Buttonville Tap") 230 kV circuits: P45 and P46[2].
- Parkway TS to Richview TS 230 kV circuits: P21R and P22R.

Western Area:

- Claireville TS to Kleinburg TS 230 kV circuits: V43 and V44[3]

The NA review shows that all flows on all transmission lines are within rating during the 2023-2032 study period except for the Claireville x Brown Hill corridor and the Parkway TS to Buttonville TS line. These are discussed below:

1) Loading on the Claireville TS to Brown Hill TS 230kV Corridor comprising the double circuit line H82/H3V and B88H/B89H will exceed the thermal limits by summer 2030.

[2] Radial from Parkway TS
[3] Radial from Claireville TS

Table 7-1 Loading on Claireville TS x Brown Hill TS Corridor

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Need Date
Armitage TS (44kV)		285	290	296	301	305	303	305	308	311	313	
Brown Hill TS (44kV)		94	100	118	121	125	124	125	125	126	126	
Holland TS (44kV)		166	173	176	179	169	169	169	169	169	169	
Northern York Station						66	80	89	99	109	118	
Vaughan MTS #4 (28kV)		101	100	128	149	148	147	146	145	143	142	
Vaughan MTS #5 (28kV)									64	132	138	
Total	850	646	663	718	750	813	823	834	911	989	1007	2030

2) Loading on the Parkway TS x Markham MTS #4 Jct. section of the 230kV Parkway TS x Buttonville TS double circuit Line P45/P46 will exceed the rating of line by summer 2028

Table 7-2 Loading on the Parkway TS x Markham MTS #4 Jct. Section of 230kV Line P45/P46

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Need Date
Buttonville TS (28kV)		144	152	154	152	160	149	148	147	146	145	
Markham MTS #4(28kV)		116	117	141	162	191	177	175	174	173	171	
Markham MTS #5(28kV)							68	136	140	139	138	
Toubner TS (28kV)						32	31	50	52	55	72	
Total	420	260	269	294	314	384	425	509	513	513	526	2028

7.1.2 Step down Transformer Station Facilities

There are a total of fifteen Hydro One and LDC owned step-down transformers stations and one direct transmission connected industrial customer owned station in the GTA North Region as given in Table 7-3 Step-Down Transformer Stations in the GTA North Region below:

Table 7-3 Step-Down Transformer Stations in the GTA North Region

Northern York Area		
Armitage TS	Brown Hill TS	Holland TS
Southern York Area		
Buttonville TS	Markham MTS #1[1]	Markham MTS #2[1]
Markham MTS #3[1]	Markham MTS #4[1]	Richmond Hill MTS[1]
Vaughan MTS #1[1]	Vaughan MTS #2[1]	Vaughan MTS #4[1]
Industrial Customer		
Western Area		
Kleinburg TS	Vaughan MTS #3[1]	Woodbridge TS

1. Stations owned by Alectra

The loadings on these stations were reviewed. Based on the forecast in Appendix C, additional capacity is required in the Northern York, Markham, and Vaughan areas starting in 2027. The station loading in each area and the associated station capacity and need dates are summarized in Table 7-**.**

Table 7-4 Adequacy of the Step-Down Transformation Facilities in the GTA North Region

Area/Supply	LTR-Capacity (MW)	2023 Summer Forecast (MW)	Need Date
Northern York Area (Armitage TS, Holland TS)	485	452	2027
Northern York Area (Brown Hill)	184	94	-
Markham / Richmond Hill transformation Capacity (Buttonville TS, Markham MTS #1, 2, 3, 4, and Richmond Hill MTS #1, 2)[1]	957	847	2028
Vaughan Transformation Capacity (Vaughan MTS #1, 2, 4)	612	551	2030
Vaughan Transformation Capacity (Vaughan MTS #3)[2]	153	145	2027
Kleinburg Area (Kleinburg TS 44kV)	97	102	Note [3]
Woodbridge TS (44kV)	80	85	Note [4]

1. Two stations required Markham MTS #5 in 2028 and Richmond Hill MTS #3 in 2032
2. Vaughan MTS #6 is a station dedicated for a large customer.
3. Excess load to be transferred to Northern York TS when new station complete in 2027
4. Loads to be managed by Hydro One Distribution

7.2 Asset Renewal Needs

No asset renewal needs have been identified in the GTA North Region over the current study period other than replacement of transformer T5 at Woodbridge TS listed in the 2020 RIP.

7.3 Load Restoration and Load Security Needs

Load Restoration and /or security needs were identified for theV43/V44, H82V/H83V, and V71P/V75P circuits in the 2020 RIP. One new load restoration need has been identified for the P45/P46 circuits. The needs and the recommended plan to address them are summarized below:

1. <u>Load restoration following loss of the Claireville TS x Kleinburg TS 230kV circuits (V43/V44).</u>

Not all loads more than 250 MW and 150 MW can be restored within 30 minutes and 4 hours respectively, as per the ORTAC restoration criteria. The RIP recommended that this need would be addressed as part of the longer-term plan to reinforce the Claireville TS to Kleinburg TS corridor. No further action was proposed at the time. This will be re-visited in the next phase of this RP cycle.

2. <u>Load Restoration following loss of the Claireville TS to Holland TS circuits (H82V/H83V).</u>

All loads exceeding 250 MW cannot be restored within 30 minutes per the ORTAC criteria. Following the loss of H82V/H83V, the normal station service supply to YEC generation is also lost. Holland TS cannot be restored from B88H/B89H until YEC generation is restored. Transferring YEC to an alternate source of station service supply cannot be completed within 30 minutes. The RIP had recommended that the IESO pursue alternative station service configurations at YEC to facilitate faster restoration of load on H82V/H83V, consistent with the load restoration criteria. This will be re-visited in the next phase of this regional planning cycle.

3. Load Security Need for the Parkway TS to Claireville TS 230kV double circuit Line V71P/V75P

The loss of this line can result in an interruption to over the 600MW which is more than what is permitted under the ORTAC criteria. The RIP had recommended that no further action is required. While the load security criteria was not met, Hydro One has installed inline switches at Grainger Jct. – located just outside of Vaughan MTS #1 - which permits quick restoration of the loads. This will be re-visited in the next phase of this regional planning cycle.

4. Load Restoration Need for the Parkway TS to Buttonville TS 230kV double circuit Line P45/P46

The line loading is expected to reach 384MW by summer 2027. Not all loads more than 250 MW and 150 MW can be restored within 30 minutes and 4 hours respectively for a double circuit outage, as per the ORTAC restoration criteria. This is a new need and will be reviewed in the next phase of this regional planning cycle.

8 NEEDS

This section identifies any new needs in the GTA North Region and reaffirms and provides an update on the needs already identified in the previous RIP.

Table 8-1 Near and Medium Terms Needs in the GTA North Region

No.	Need	Recommended Action Plan	Need Date[1]
Needs as per last RIP[2]			
1	Northern York Area: Step-down Transformation Capacity	Build new Northern York Station	2027
2	Woodbridge TS: End-of-life of transformer T5	Replace the end-of-life transformer with similar type and size equipment as per current standard	2027
3	Markham Area: Step-down Transformation Capacity	Build new Markham #5 MTS and connect to 230kV circuits P45/P46	2028
4	Increase Capability of 230kV Circuits P45+P46 (supply Buttonville TS, Markham #4 MTS, and future Markham #5 MTS)	Uprate circuits P45/46 from Parkway to Markham MTS #4 Jct.	2028
5	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan MTS #5	2030
6	Claireville X Brownhill Circuit Upgrade	Uprate circuits- H82/H3V and B88H/B89H	2030
7	Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, and V71P/V75P[3]	To be reviewed in next phase of this regional planning cycle	Existing
New Needs identified			
8	Kleinburg TS Area	Transfer load to Northern York TS	2027
9	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan MTS #6 and connect to 230kV circuit V43/V44	2027
10	Markham Area: New Customer Connection	Build New Toubner TS and line tap to 230kV circuits P45/46	2027
11	Richmond Hill Area: Step-down Transformation Capacity	Build new Richmond Hill #3 MTS	2032
12	Load Restoration for 230kV circuits P45/46	To be reviewed in next phase of this regional planning cycle	2027

1. Need date based on current forecast
2. Please see Reference 1 in Section 11
3. No action was considered necessary for these needs in the last regional Planning cycle. Needs will be reviewed again in the IRRP and RIP phases of this regional planning cycle.

8.1 Station and Transmission Capacity Needs in the Near and Medium Term

As shown in the Table above, the 2020 RIP had identified three new station capacity needs, one in the Markham area designated as Markham MTS #5, the second in the Vaughan Area, designated as Vaughan MTS #5 and the third in the Northern York Area, designated as Northern York TS. Since then, based on the current load forecast and customers' request, the need for three additional stations has been identified over the study period - Richmond Hill MTS #3, Vaughan MTS #6 and Toubner TS.

8.1.1 Markham Area - Build Markham MTS #5 and Uprate circuits P45/P46 -2028

Markham MTS #5 was previously identified to provide additional step-down transformation capacity in Markham-Richmond Hill area and planned to be built adjacent to the Buttonville TS and supplied from the same 230kV Parkway TS x Buttonville TS circuits P45/P46 (See Figure 8-1 below). The new station will have 2 x75/125MVA, 230/27.6kV transformers and a 27.6kV switchgear building.

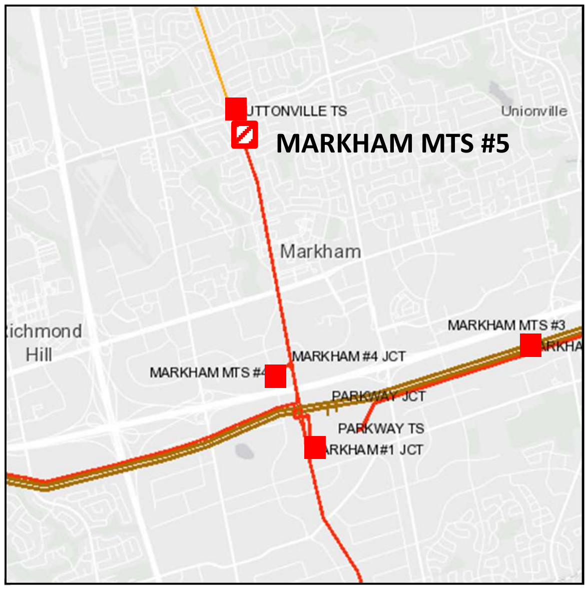


Figure 8-1: Markham MTS #5 Location

The TWG reaffirmed the need to build the new Markham MTS #5 and to uprate the limiting section of the P45/P46 line between Parkway TS and Markham MTS #4 Jct. to provide the needed capacity. The station project need date based on current forecast is summer 2028 (See Table 7-4) and the lines project need date is summer 2028 (see Table 7-2). This will be re-visited in the next phase of this regional planning cycle.

8.1.2 Northern York Region - Build Northern York Area TS and supply from 230kV Line B88H/B89H - 2027

The Northern York Area TS was recommended to be built in the Northern York Region to provide additional step-down transformation capacity in the Bradford, East Gwillimbury, and Newmarket area. This area is currently supplied from Armitage TS and Holland TS and total area load is forecast to exceed the capacity of these existing two stations by summer 2027 as shown in Table 8-2 below.

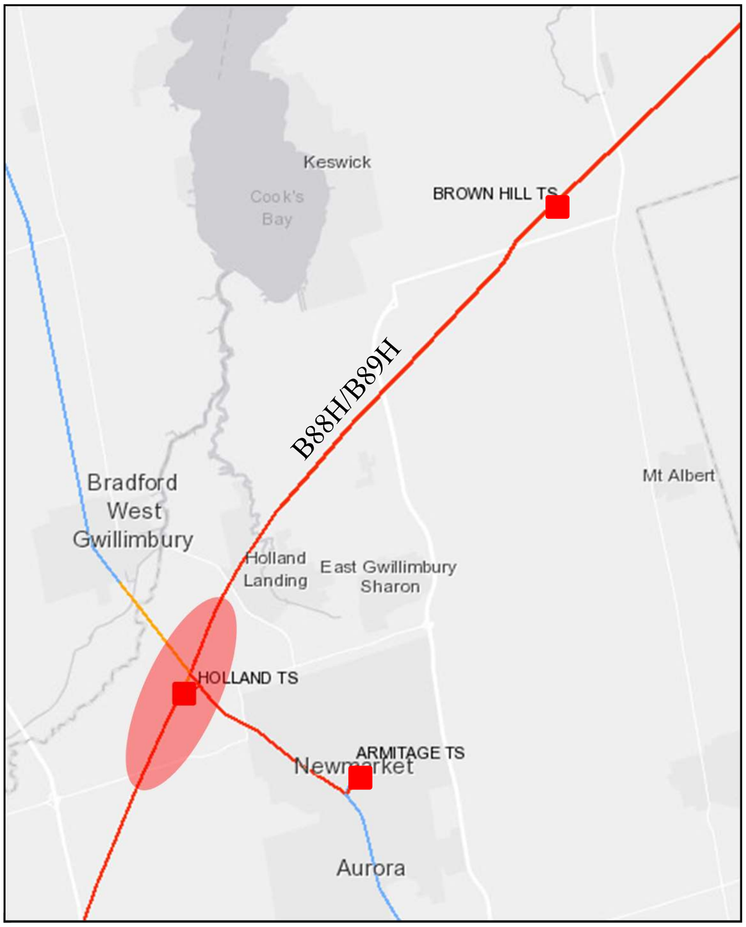


Figure-8-2 Northern York Area TS – Potential Location

Table 8-2: Northern York Area Capacity Need

Transformer Station	LTR	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Armitage TS (44kV)	317	285	290	296	301	305	303	305	308	311	313
Holland TS (44kV)[1]	169	166	173	176	179	169	169	169	169	169	169
Northern York Station	170					66	80	89	99	109	118
Total	485	451	463	472	480	540	552	564	577	589	600

1. Holland load above LTR to be transferred to new Northern York station.

The TWG has reaffirmed the need for building a new station close to these two stations, in the area shown in Figure 8-2. The new station is planned to be supplied from 230kV double circuit line H82V/H83V or B88H/B89H and planned to have 2x75/125MVA, 230/44-27.6kV transformers and 27.6kVand 44kV switchyards. The new station should increase the transformation capacity in Northern York Region by about 170 MW. The station location and timing will be further discussed with the area LDCs in the next phase of the regional planning process.

8.1.3 Vaughan Area – Build Vaughan MTS #5 and supply from 230kV Line H82V/H83V -2030

The Vaughan MTS #5 was previously identified to provide additional step-down transformation capacity in Vaughan area and planned to be built adjacent to the existing Vaughan MTS #4 – see Figure 8-3. The new station is planned to have 2 x75/125MVA, 230/27.6kV transformers, a 27.6kV switchgear building and is planned to be supplied from the 230kV double circuit line H82V/H83V.

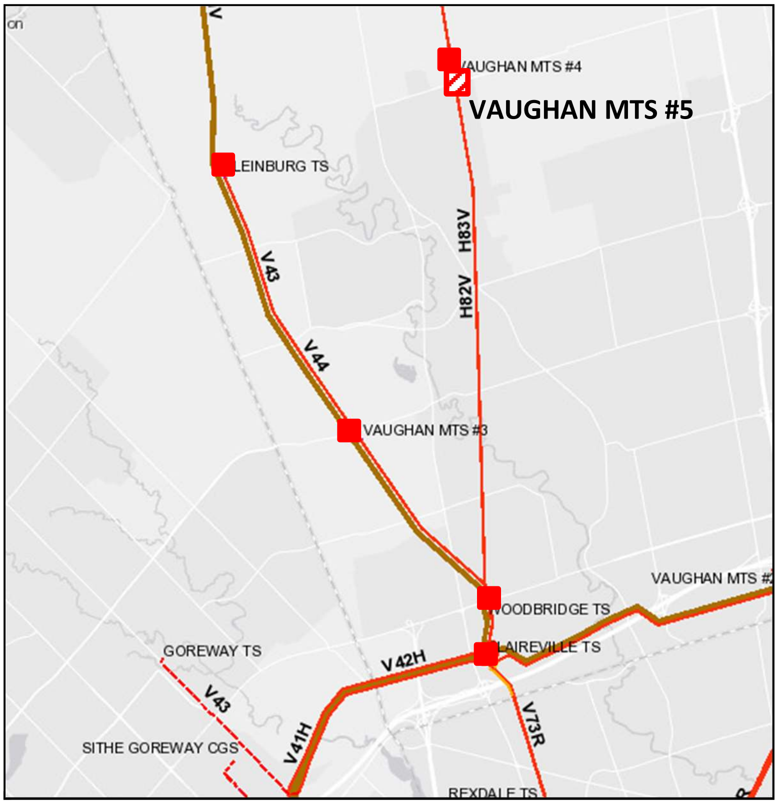


Figure-8-3 Vaughan MTS #5 Location

Table 8-3: Vaughan Area Station Capacity Need

Transformer Station	LTR	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Vaughan MTS #1 (28kV)	306	301	297	294	291	288	286	283	281	279	277
Vaughan MTS #2 (28kV)	153	149	148	147	145	144	143	141	141	139	138
Vaughan MTS #4 (28kV)	153	101	100	128	149	148	147	146	145	143	142
Vaughan MTS #5 (28kV)									64	132	138
Total	612	551	545	569	585	580	575	570	631	694	696

As mentioned in Table 7-1, there isn't sufficient transmission capacity available on the Claireville to Brown Hill corridor to fully supply Vaughan MTS #5, given that a new station in Northern York is anticipated by 2027. Therefore, a plan to increase transmission supply capability to the area will be required before a plan for the new transformation station in Vaughan can be committed. This will be addressed in the next phase of this regional planning cycle.

8.1.4 Kleinburg TS Area – Transfer Load to Northern York TS

Kleinburg TS 44kV loading is a newly identified need. Kleinburg TS has 2 x 75/125MVA, 230/44-27.6kV transformers with separate 44kV and 27.6kV switchyards. Significant new load is forecast to connect at 44kV in the 2023-2024 period as shown in Table 8-4 below.

Table 8-4 Kleinburg Area Station Capacity Load

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Kleinburg TS (28kV)	91	62	65	81	92	95	95	95	95	95	95
Kleinburg TS (44kV)	97	102	111	124	134	98	98	97	96	95	95
Load Transfer to be Managed		5	14	27	37						

To manage loading at Kleinburg TS, Hydro One DX intends to transfer loads in the northern area served by Kleinburg TS to the new Northern York TS planned to be in-service by 2027.The new Northern York TS is planned to be a 230/44-27.6kV station. The TWG will review this in the next phase of the regional planning cycle.

8.1.5 Vaughan Area – Build Vaughan MTS #6 and supply from 230kV Line V43/V44 - 2027

Vaughan MTS #6 is a new identified need. Alectra plans to build a new station to provide dedicated supply to a large customer. The new station will have 2 x 75/125MVA, 230/27.6kV transformers and a 27.6kV switchgear building. Alectra has requested that Hydro One build a short underground line tap to supply the new station from the 230kV Claireville TS x Kleinburg TS double circuit line V43/V44. The planned in-service date for the station is the end of 2027.

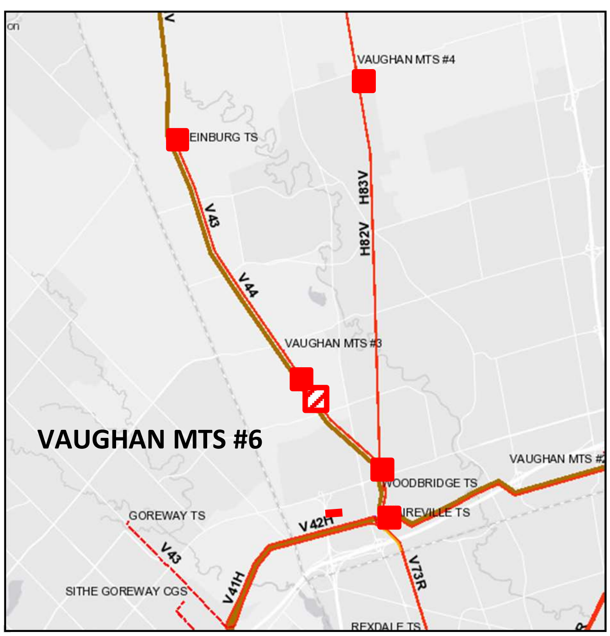


Figure-8-4 Vaughan MTS #6 Location

Table 8-5: Loading on the 230kV Claireville TS x Kleinburg TS line V43/V44

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Kleinburg TS (28kV)		62	65	81	92	95	95	95	95	95	95
Kleinburg TS (44kV)		102	111	124	134	98	98	97	96	95	95
Vaughan MTS #3 (28kV)		117	118	118	145	145	145	145	145	145	145
Vaughan MTS #6 (28kV)						32	31	50	52	68	72
Woodbridge TS (28kV)		87	86	79	79	78	78	77	77	76	77
Woodbridge TS (44kV)		85	85	86	86	86	87	87	88	90	91
Total	620	453	465	487	536	534	533	552	553	569	575

Table 8-5 shows the forecast loads connected to the line. As shown, there is adequate capacity to supply the loads over the study period.

Hydro One is currently in initial consultations with Alectra on the connection. Further details will be discussed in the next phase of the regional planning cycle.

8.1.6 Richmond Hill Area – Build Richmond Hill MTS #3 and supply from 230kV Line V71P / V75P - 2032

Richmond Hill MTS #3 is a new identified need. Alectra plans to build a new station to meet forecast loads in the 2030s. The new station will have 2 x 75/125MVA, 230/27.6kV transformers and a 27.6kV switchyard. Alectra has requested Hydro One to connect the new station to the 230kV Claireville TS x Parkway TS double circuit line V71P/V75P. The planned in-service date is summer 2032.

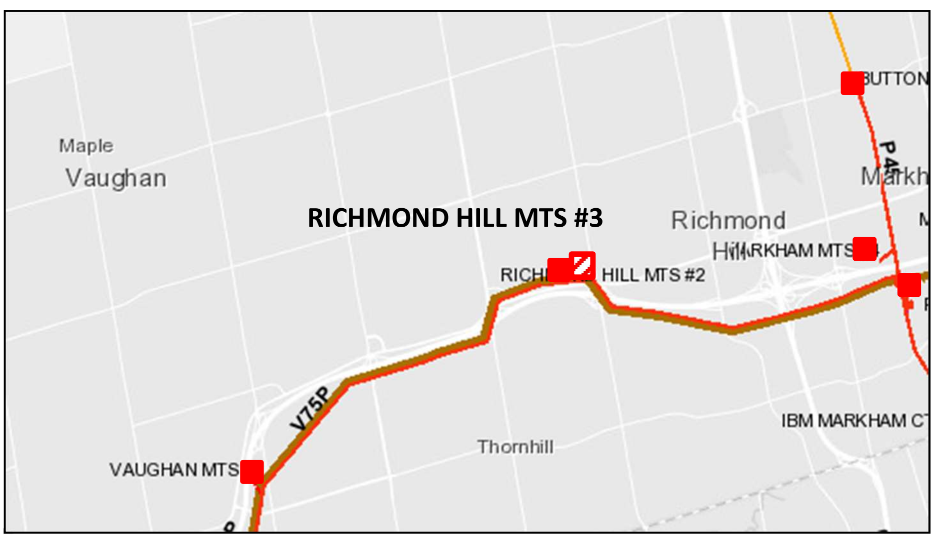


Figure-8-5 Richmond Hill MTS #3 Location

The 2020 RIP report had previously identified load security concerns with the V71P/V75P line as the connected loads exceed the 600 MW limit as per the ORTAC security criteria. However, as discussed in

Section 7.3, no action was recommended as Hydro One had installed sectionalizing switching on the line to restore load quickly in the event of a double circuit outage. The connection of the new station will further increase loading on the line. Alternatives to connect the station and address the load security need on the circuits will be developed and considered in the next phase of this RP cycle.

8.1.7 Toubner TS - 2027

Toubner TS is a new identified need. Hydro One has been requested to build a dedicated step-down transformer station for a direct industrial customer. The station will have 2 x 75/125 MVA, 230/27.6 kV transformers and a 27.6kV switchyard. The new station is in the Hwy. 7 and Hwy. 404 area and will be supplied from a tap for the 230kV line P45/P46 line tapped just north of Parkway TS. There is adequate capacity to supply the new station over the study period. The planned in-service date for the project is 2027.

Hydro One is currently in consultations with the customer to prepare connection estimates for the customer. Further details may be discussed in the current regional planning cycle.

8.1.8 Claireville x Brown Hill Transmission capacity Need- 2030

As described in Section 6.1 loading on the Claireville TS x Brown Hill TS corridor will exceed supply capacity by 2030. Alternatives to address this need will be developed and considered in the next phase of this regional planning cycle.

8.2 Long-Term Capacity Needs

With the provincial focus on decarbonization and the move away from fossil fuels, there will be a greater reliance on electricity. The GTA North region along with the rest of the province is about to embark on period of growth over the longer term driven by electrification, and large-scale development and customer connection projects are expected in several areas within the GTA North Region. The TWG will work with other stakeholders to ensure that all regional needs are met in a timely manner.

8.3 Asset Renewal Needs for Major HV Transmission Equipment – Woodbridge TS

As mentioned in Section 7.2 no asset renewal needs have been identified in the GTA North Region over the current study period other than Woodbridge TS identified in the last RIP.

Woodbridge TS comprises one DESN unit, T3/T5 (75/125 MVA), with two secondary winding voltages at 44 kV and 27.6 kV, each with a summer 10-Day LTR of 80 MW, supplying both Alectra and THESL. The station's 2022 44KV and 27.6kV actual peak loads were 55MW and 78 MW, respectively. Transformer T5 is currently about 51 years old and has been identified to be at its EOL.

The TWG is confirming the previous RIP identified need for the replacement of Woodbridge TS T5 transformer with similar type and size equipment as per current standard. Under this alternative the existing transformer T5 at Woodbridge TS is replaced with a new 75/125 MVA 230/44-27.6 kV transformer. This alternative would address the need and would maintain reliable supply to the customers in the area. The planned in-service date for the work is 2027.

8.4 Load Restoration and Security Needs

Load restoration need have been discussed earlier in Section 7.3, The TWG will consider these needs in the development of new plans to meet load growth and improve reliability of supply in the GTA North Region in the next phase of this regional planning cycle.

9 SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

The uncertainty can stem from varying factors ranging from changes considered in potential evolution of public policy, electrification (e.g., electrification of transportation or other sectors), Municipal Energy Plans, Community Energy Plans, and Climate Action Plans (for actions that are not firm/committed), non-committed customer connections (both distribution and transmission), DER scenarios (e.g., battery storage), continued operation of off-contract generation.

A high demand growth forecast was developed by assuming that the forecast growth was 50% higher than the extreme summer corrected normal growth net load forecast given in Appendix C. Similarly, a low demand forecast was developed assuming that the growth was half the extreme summer corrected Normal Growth net load forecast.

The impact of sensitivity analysis for the high and low growth scenarios on the capacity needs identified in Table 8-1 is summarized in Table 9-1.

Table 9-1: Impact of Sensitivity Analysis on the Identified Capacity Needs

No.	Need	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Toubner TS[1]	2027		
2	Vaughan MTS #6[1]	2027		
3	Northern York TS	2027	2026	2027
4	Markham MTS #5	2028	2027	2032
5	Vaughan MTS #5	2030	2030	2031
6	Richmond Hill MTS #3	2032	2029	Beyond 2032
7	Uprate circuits P45/P46[2]	2028	2028	Beyond 2032
8	Claireville X Brown Hill Corridor	2030	2027	Beyond 2032

[1]Customer requested work with defined in-service date.

[2]To be done along with the Markham MTS #5 project

Based on current equipment deliverability and construction schedules the earliest in-service dates for projects is summer 2027. The Toubner TS, Vaughan MTS #6 are customer driven projects and need to proceed. The remaining needs listed in Table 9-1will be addressed in the next phases of this planning cycle in coordination with the additional identified network capacity and load security/restoration needs and considering a longer-term forecast for the area.

10 RECOMMENDATIONS

The TWG's recommendations are as follows:

a) No further regional coordination is required for the following needs and work will be proceeding as planned with all the three projects expected to be in-service by 2027.

- Woodbridge TS: Replace transformer T5
- Toubner TS: Build new station.
- Vaughan MTS #6: Build new station

b) Further assessment and regional coordination is required in the next phases of the regional planning cycle to review and/or develop a preferred plan for the follow needs:

- Markham MTS #5: Build new station
- 230kV circuit P45/P46: Uprate circuits between Parkway TS and Markham MTS #4 Jct.
- Northern York TS: Build new station
- Kleinburg TS 44kV: 44kV loads transfer to Northern York TS
- Vaughan MTS #5: Build new station
- Richmond Hill MTS #3: Build new station
- Claireville TS x Brown Hill TS Transmission circuit capacity need
- Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, P45/P46, and V71P/V75P.

11 REFERENCES

[1]. Hydro One, "GTA North Regional Infrastructure Plan", October 22, 2020.
GTA North REGIONAL INFRASTRUCTURE PLAN (hydroone.com)

[2]. Hydro One, "Need Assessment Report, GTA North Region", March 18, 2018.
Needs Assessment Report GTA North Region (hydroone.com)

[3]. IESO, "York Region: Integrated Regional Resource Plan", February 28, 2020.
York IRRP-20200228.pdf

[4]. IESO, "York Region Scoping Assessment Outcome Report", August 28, 2018.
York-Region-Scoping Assessment-Outcome-Report-20180828.pdf

12 APPENDIX A. STATIONS IN THE GTA NORTH REGION

No.	Station (DESN)	Voltage (kV)	Supply Circuits
1	Armitage TS T1/T2	230/44	B88H/B89H
	Armitage TS T3/T4	230/44	B88H/B89H
2	Brown Hill TS T1/T2	230/44	B88H/B89H
3	Buttonville TS T3/T4	230/27.6	P45/P46
4	CTS	230/13.8	P21R/P22R
5	Holland TS T1/T2, T3/T4	230/44	H82V/H83V
6	Kleinburg TS T1/T2 27.6	230/27.6	V44/V43
	Kleinburg TS T1/T2 44	230/44	V44/V43
7	Markham MTS #1 T1/T2	230/27.6	P21R/P22R
8	Markham MTS #2 T1/T2	230/27.6	C35P/C36P
9	Markham MTS #3 T1/T2	230/27.6	C35P/C36P
	Markham MTS #3 T3/T4	230/27.6	C35P/C36P
10	Markham MTS #4 T1/T2	230/27.6	P45/P46
11	Richmond Hill MTS #1 T1/T2	230/27.6	V71P/V75P
	Richmond Hill MTS #2 T3/T4	230/27.6	V71P/V75P
12	Vaughan MTS #1 T1/T2	230/27.6	V71P/V75P
	Vaughan MTS #1 T3/T4	230/27.6	V71P/V75P
13	Vaughan MTS #2 T1/T2	230/27.6	V71P/V75P
14	Vaughan MTS #3 T1/T2	230/27.6	V44/V43
15	Vaughan MTS #4 T1/T2	230/27.6	H82V/H83V
16	Woodbridge TS T3/T5 27.6	230/27.6	V44/V43
	Woodbridge TS T3/T5 44	230/44	V44/V43

13 APPENDIX B. TRANSMISSION LINES IN THE GTA NORTH REGION

Line	Circuit Designations	Voltage (kV)
Claireville TS to Holland TS	H82V/H83V	230
Holland TS to Brown Hill TS	B88H / B89H	230
Claireville TS to Kleinburg TS	V43/V44	230
Claireville TS to Parkway TS	V71P/V75P	230
Parkway TS to Markham MTS #1 and CTS	P21R/P22R	230
Parkway TS to Buttonville TS	P45/P46	230
Parkway TS to Cherrywood TS	C35P/C36P	230

14 Appendix C: Non-Coincident Summer Peak Net Load Forecast (2023 to 2032)

	LTR	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Armitage TS (44kV)	317	285	290	296	301	305	303	305	308	311	313
Brown Hill TS (44kV)	184	94	100	118	121	125	124	125	125	126	126
Buttonville TS (28kV)	166	144	152	154	152	160	149	148	147	146	145
Holland TS (44kV)	169	166	173	176	179	169	169	169	169	169	169
Kleinburg TS (28kV)	91	62	65	81	92	95	95	95	95	95	95
Kleinburg TS (44kV)[1]	97	102	111	124	134	98	98	97	96	95	95
Markham MTS #1 (28kV)	81	80	79	78	77	76	76	75	74	74	73
Markham MTS #2 (28kV)	101	88	98	97	96	106	94	93	93	92	91
Markham MTS #3 (28kV)	202	171	184	191	189	197	186	184	183	181	180
Markham MTS #4(28kV)	153	116	117	141	162	176	177	175	174	173	171
Markham MTS #5(28kV)	153						68	136	140	139	138
Northern York Station	170					66	80	89	99	109	118
Richmond Hill-1 MTS (28kV)	153	153	152	150	149	154	146	144	144	142	141
Richmond Hill-2 MTS (28kV)	101	95	105	104	104	111	104	104	104	105	105
Richmond Hill-3 MTS (28kV)	153										60
Toubner TS (28kV)	153					32	31	50	52	55	72
Vaughan MTS #1 (28kV)	306	301	297	294	291	288	286	283	281	279	277
Vaughan MTS #2 (28kV)	153	149	148	147	145	144	143	141	141	139	138
Vaughan MTS #3 (28kV)	153	117	118	118	145	145	145	145	145	145	145
Vaughan MTS #4 (28kV)	153	101	100	128	149	148	147	146	145	143	142
Vaughan MTS #5 (28kV)	153								64	132	138
Vaughan MTS #6 (28kV)	153					32	31	50	52	68	72
Woodbridge TS (28kV)	80	87	86	79	79	78	78	77	77	76	77
Woodbridge TS (44kV)	80	85	85	86	86	86	87	87	88	90	91
Grand Total		**2396**	**2459**	**2559**	**2652**	**2792**	**2814**	**2921**	**2997**	**3084**	**3173**

1. Kleinburg 44kV load exceeds LTR between 2023 and 2026. Excess load planned to be transferred to Northern York Region when station is built in 2027.

15 APPENDIX D: ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
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
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
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station (LDC owned)
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
RP	Regional Planning
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

IESO response to Toronto Hydro REG Investments Plan 2025 – 2029

As part of the OEB's Filing Requirements for Electricity Distribution Rate Applications, a distributor must submit a letter of comment from the Independent Electricity System Operator (IESO) on its Renewable Energy Generation (REG) Investments Plan, which is part of its Distribution System Plan (DSP).

The OEB issued the 2023 Edition of Chapter 5 for 2024 Rate Applications on December 15, 2022 wherein section 5.2 Distribution System Plans, under "Renewable Energy Generation (REG)" states:

"A distributor is expected to coordinate with the IESO in relation to REG investments and confirm if there are REG investments in the region.

If there are REG investments proposed in the DSP, a distributor is expected to demonstrate that it has coordinated with the IESO, other distributors, and/or transmitters, as applicable, and that the investments proposed are consistent with a Regional Infrastructure Plan. This coordination is demonstrated by a comment letter provided by the IESO, to be filed with the DSP."

On August 29, 2023, the IESO received a letter from Toronto Hydro-Electric System Limited (Toronto Hydro) outlining its REG Investments Plan (Plan) for comment. The IESO has reviewed Toronto Hydro's Plan and provides its comments as follows.

IESO Comments

The IESO notes that Toronto Hydro's service territory is within the Toronto region. The Toronto region is currently undergoing its third cycle of regional planning[1] and is currently at the Integrated Regional Resource Plan (IRRP) stage as of September 2023. The Toronto region completed its second cycle of regional planning with the publication of the Regional Infrastructure Plan (RIP) by Hydro One Networks Inc. in March 2020[2]. Toronto Hydro is an active, participating member of the regional planning study team.

[1] Toronto Regional Planning, IESO. https://www.ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/Toronto

[2] Hydro One's Regional Infrastructure Plan, March 2020. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/toronto/Documents/Toronto%20Regional%20Infrastructure%20Plan_Mar6%202020.pdf

Toronto Hydro – Renewable Energy Generation Investments (2025-2029)

Toronto Hydro states that there are currently 305 MW of installed distributed energy resource (DER) capacity on their distribution system as of end of 2022, 116 MW of which are considered as REG. Toronto Hydro anticipates that there will be 200 MW of REG connected to their distribution system by the end of the DSP planning period in 2029. The forecasted REG and other DER connections over the Plan period (2025-2029) is being coordinated as a planning input into the regional planning process currently underway.

With respect to investments in Toronto Hydro's Plan, the IESO confirms that although it includes renewable enabling improvements (REIs) investments of an estimated $57.5 million over the Plan period for installation of bus tie reactors to alleviate short circuit constraints, improving monitoring and control to ensure safe operation of DERs (particularly during faults), and deploying energy storage systems to alleviate distribution system constraints, these investments are not a result of outcomes from the regional planning processes as outlined above. These REI investments are proposed by Toronto Hydro to improve the ability of Toronto Hydro's distribution system to accommodate REG, which is not in scope of regional planning. Therefore, the IESO has no comment on these investments.

The IESO appreciates the opportunity provided to review Toronto Hydro's Plan and looks forward to continue working together in the regional planning process.

C Performance Measurement

C1 Overview of Performance Framework

In developing its approach to performance measurement for the Distribution System Plan ("DSP"), Toronto Hydro considered the Ontario Energy Board's guidance, including the *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRF").[1] A key theme of the Ontario Energy Board's guidance is that utilities should align their investment plans with customer needs, and adopt an outcomes-based approach to tracking their performance.

Toronto Hydro's 2025-2029 performance measurement framework consists of (1) performance outcomes consistent with the Ontario Energy Board's Renewed Regulatory Framework (RRF) categories, and (2) a custom scorecard that is tied to an innovative Performance Incentive Mechanism ("PIM") as part of the 2025-2029 custom rate framework (Exhibit 1B, Tab 2, Schedule 1).

In respect of the first component – RRF outcomes – Toronto Hydro intends to continue delivering high-performance on the Electricity Distributor Scorecard ("EDS") and the Electricity Service Quality Requirements ("ESQR") consistent with the historical results presented in Exhibit 1B, Tab 3, Schedule 2. To that end, each capital and operational program outlined in the DSP and Exhibit 4, Tab 2 (operations) includes a performance outcomes table that explains how the program advances specific RRF objectives.

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, or make necessary day-to-day operational investments. The choices made reflect 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.

Toronto Hydro sets asset management objectives that are aligned with the overall investment plan objectives, and are a result of the detailed, iterative, and customer engagement-driven planning process summarized in Section E2 of the DSP. Section D1.2.1 explains the link between Toronto Hydro's distribution system Asset Management System ("AMS") and its performance measurement framework with respect to the investment priorities of the plan.

[1] Ontario Energy Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (October 18, 2012).

As further detailed in Exhibit 1B, Tab 3, Schedule 1, Toronto Hydro's 2025-2029 Custom Scorecard tracks performance across four performance categories. By monitoring and managing the performance measures identified in each category of the custom scorecard (see Table 1 below), in addition to the EDS, ESQR and Asset Management performance measures noted above, the utility expects to drive continuous and sustained improvement across the organization in the next rate period in a manner that aligns with Ontario Energy Board and customer feedback, and also reflects the key objectives and underpinnings of the plan.

Table 1: Investment Category Trigger Drivers

Performance Category	Outcome and Measure
System Reliability & Resilience	**Outage Duration:** System Average Interruption Duration Index (SAIDI) excluding MEDs, Loss of Supply and Planned Outages
	Outage Frequency: System Average Interruption Frequency Index (SAIFI) - Defective Equipment
	System Security Enhancements: Deliver initiatives that enhance Toronto Hydro's physical and cyber security posture against the NIST framework
Customer Service & Experience	**New Services Connected on Time:** Percentage of new connections and service upgrades completed on time consisting of Low Voltage Connections (70%), High Voltage Connections (20%) and DER Connections (10%)
	Customer Satisfaction: Customer post-transactional surveys for Phone Inquiries, E-Mail Inquiries, Key Accounts engagements, Construction Communications, Outages Communications, and Customer Connections
	Customer Escalations Resolution: Percentage of customer escalations resolved within 10 business days.
Environment, Safety and Governance	**Total Recordable Injury Frequency (TRIF):** Injuries per 100 employees (or 200,000 hours worked) per year.
	Emissions Reductions: CO2e emissions produced by the utility's fleet and facilities.
	ISO Compliance and Certification: Achieve and maintain certification with select ISO governance standards, specifically achieve ISO 55001 (60%), and maintain ISO14001 (20%) and ISO45001 (20%).
Efficiency & Financial Performance	**Efficiency Achievements:** Sustained benefits for customers in the form of reduced or avoided costs or other benefits that will produce a lower revenue requirement in the next rebasing
	Grid Automation Readiness: Completion of technology milestones that will enable the implementation of fully automated, self-healing grid operations beginning in 2030
	System Capacity (Non-Wires): Flexible system capacity procured through demand response offerings.

The section that follows explains Toronto Hydro's reliability performance over the 2018-2022 period in accordance with Chapter 5 Filing Requirements.[2] For details regarding Distributor Specific Reliability Targets, please refer to Exhibit 1B, Tab 3, Schedule 1 for the reliability targets proposed as part of Toronto Hydro's 2025 Custom Scorecard.

C2 Historical Reliability Performance

Toronto Hydro tracks reliability performance indicators System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") in several ways:

1. All events – Including Major Event Days ("MEDs") and Loss of Supply ("LoS");
2. Excluding events relating to LoS;
3. Excluding events relating to MEDs;
4. Excluding MEDs and LoS; and
5. Excluding MEDs, LoS, and Scheduled Outages.

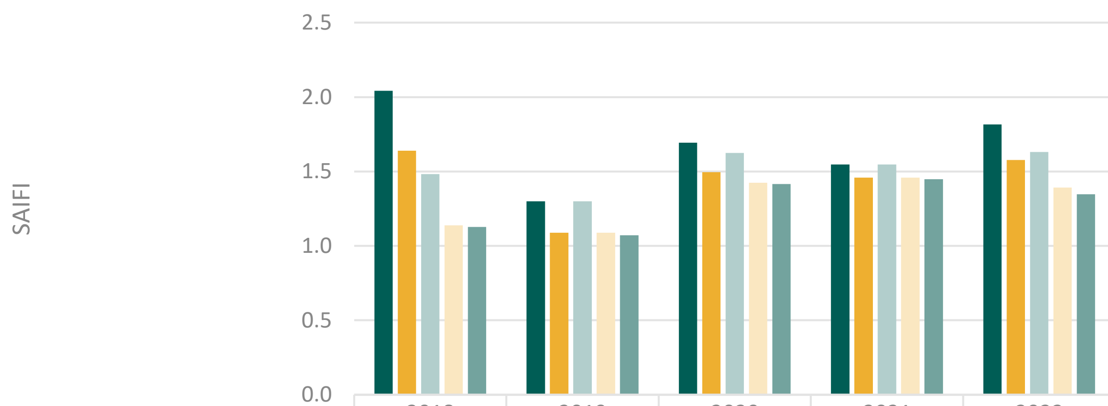
Scenarios 1, 2, 3, 4, and 5 provide SAIFI and SAIDI in the manner required by the Ontario Energy Board's prescribed Appendix 2-G, filed at Exhibit 1B, Tab 3, Schedule 2. Scenario 4 is also consistent with the Ontario Energy Board Electricity Distributor Scorecard and MD&A discussed in Exhibit 1B, Tab 3, Schedule 2. Scenario 5 provides SAIFI and SAIDI excluding MEDs, LoS, and Scheduled Outages as a more normalized reflection of total system reliability performance. Each scenario provides valuable information as to the causes, duration, and frequency of outages within Toronto Hydro's distribution system.

C2.1 System Overview

Figures 1 and 2 below show the system's total SAIFI and SAIDI between 2018 and 2022, respectively, under each of the five scenarios. The notably higher SAIFI and SAIDI in 2018 under Scenarios 1 and 2 can be attributed to a transformer fire at Finch Transformer Station ("TS") in July (counted as both a Loss of Supply event and a MED), in addition to multiple storms that occurred in April, May, and June of that year. These occurrences were outside the utility's control and met the definition of MEDs as set out in the Ontario Energy Board's Electricity Reporting and Record Keeping Requirements

[2] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 5 (December 15, 2022) at pages 7-8.

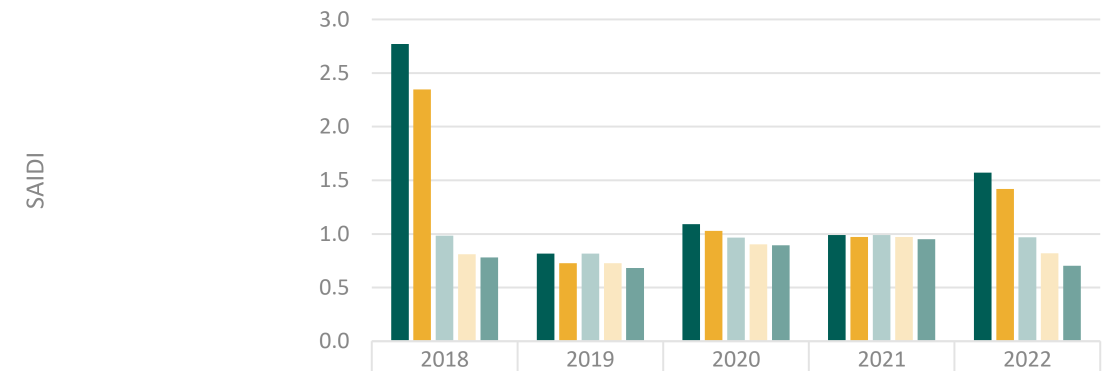
("RRR").[3] As a result, these MEDs caused the year-over-year fluctuations to be more drastic. In contrast, Scenario 3 (excluding MEDs), Scenario 4 (excluding MEDs and LoS), and Scenario 5 (excluding MEDs, LoS, and scheduled outages) illustrate more normalized SAIFI and SAIDI values with less fluctuations. Toronto Hydro considers these latter scenarios to offer greater insight into system reliability as they provide a better indication of the performance trend of the system and the impact of recent investments, and are the more commonly used indicators across the industry for benchmarking against distribution system performance. With the more normalized scenarios, there has been some worsening of performance, especially for SAIFI, over 2020-2022 and this is largely attributed to external factors, such as unknown causes or foreign interference, although defective equipment has also contributed. Additional discussion of this is provided in Sections 5-10 below.



	2018	2019	2020	2021	2022
Total SAIFI	2.04	1.30	1.69	1.55	1.82
SAIFI Excluding LOS	1.64	1.09	1.50	1.46	1.58
SAIFI Excluding MED's	1.48	1.30	1.62	1.55	1.63
SAIFI Excluding MED's and LOS	1.14	1.09	1.42	1.46	1.39
SAIFI Excluding MED's, LOS and Scheduled Outages	1.13	1.07	1.42	1.45	1.35

Figure 1: System Level SAIFI

[3] Ontario Energy Board, Electricity Reporting and Record Keeping Requirements ("RRR"), Section 2.1.4.2(4). (Effective March 31, 2020).



	2018	2019	2020	2021	2022
Total SAIDI	2.77	0.82	1.09	0.99	1.57
SAIDI Excluding LOS	2.35	0.73	1.03	0.97	1.42
SAIDI Excluding MED's	0.98	0.82	0.97	0.99	0.97
SAIDI Excluding MED's and LOS	0.81	0.73	0.90	0.97	0.82
SAIDI Excluding MED's, LOS and Scheduled Outages	0.78	0.68	0.90	0.95	0.70

Figure 2: System Level SAIDI

Since the early 2000s, Toronto Hydro has utilized its standalone Interruption Tracking Information System ("ITIS") to store historical reliability data. ITIS relies on manual entry of outage information, and its data is used to carry out reliability-driven analyses and to track reliability performance of the system.

Toronto Hydro upgraded its existing Outage Management System with Oracle's Network Management System ("NMS"). This new system provides Toronto Hydro with more robust data and enhanced visibility into near real-time system events.[4] As part of the multi-year NMS upgrade initiative, Toronto Hydro is implementing a new commercial solution, Oracle's Utility Analytics ("OUA"), which will serve as the future successor to ITIS. OUA will streamline Toronto Hydro's interruption and reliability reporting process and seamlessly integrate with NMS.

These upgrades have and will continue to improve the data quality and accuracy of Toronto Hydro's interruption tracking and reporting. Some of these changes have resulted in higher reliability trends in 2022 when compared to historical years. Furthermore, the following changes are expected over the course of the multi-year upgrade, leading to more interruptions being captured in 2023 to 2029:

[4] For more information refer to Emergency Response at Exhibit 4, Tab 2, Schedule 5 and Control Centre Operations at Exhibit 4, Tab 2, Schedule 7.

1. Increased number of outages affecting a small number of customers.
2. Improved resolution of outage duration, down to the second.
3. Increased number of scheduled outages reported; and
4. Changes in outage structuring: currently, outages are structured manually, typically broken down by feeder. OUA will streamline this process by automatically generating outage reports based on restoration actions recorded in NMS.

C2.2 Loss of Supply

Loss of Supply ("LoS") events have a significant impact on the overall reliability of Toronto Hydro's distribution system, and being external to Toronto Hydro's operations and control, are generally excluded from a system reliability analysis. On a system level, LoS events can contribute up to 20 percent of SAIFI and 15 percent of SAIDI (based on system reliability analysis beginning in 2018), although significant variations can occur year to year. There are also considerable variations between individual LoS events, which makes it difficult to perform trend analyses and forecast future reliability performance. For instance, 21 LoS events occurred in 2019, whereas 42 LoS events occurred in 2022. Nevertheless, the fewer events in 2019 affected SAIFI and SAIDI to a greater extent due to higher impacts of individuals events in that year. Figures 3 and 4 below show the SAIFI and SAIDI system impact due to LoS events.

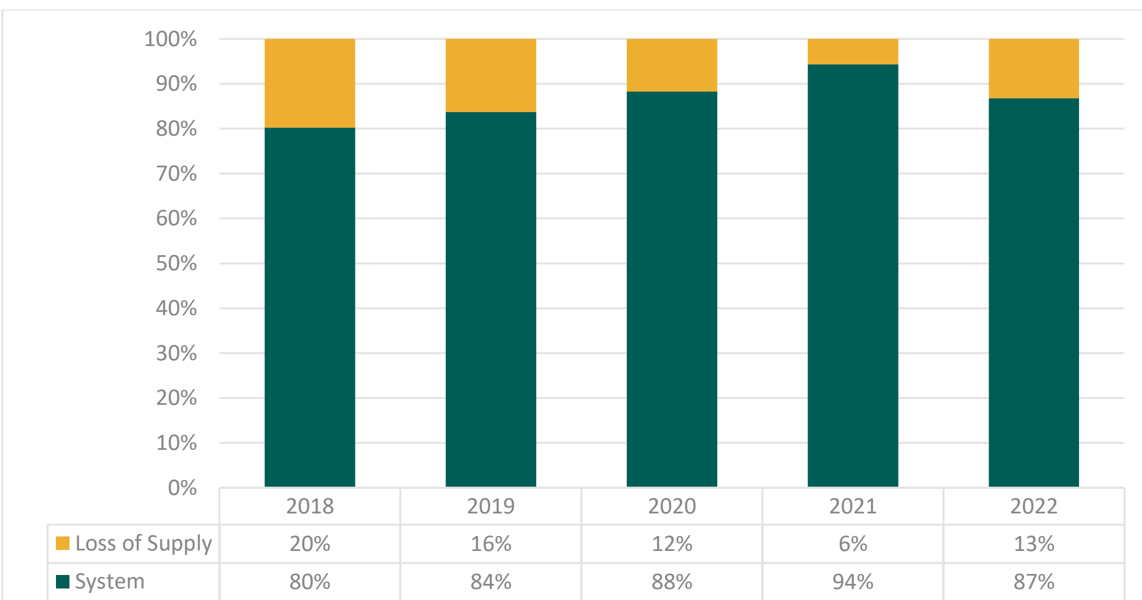
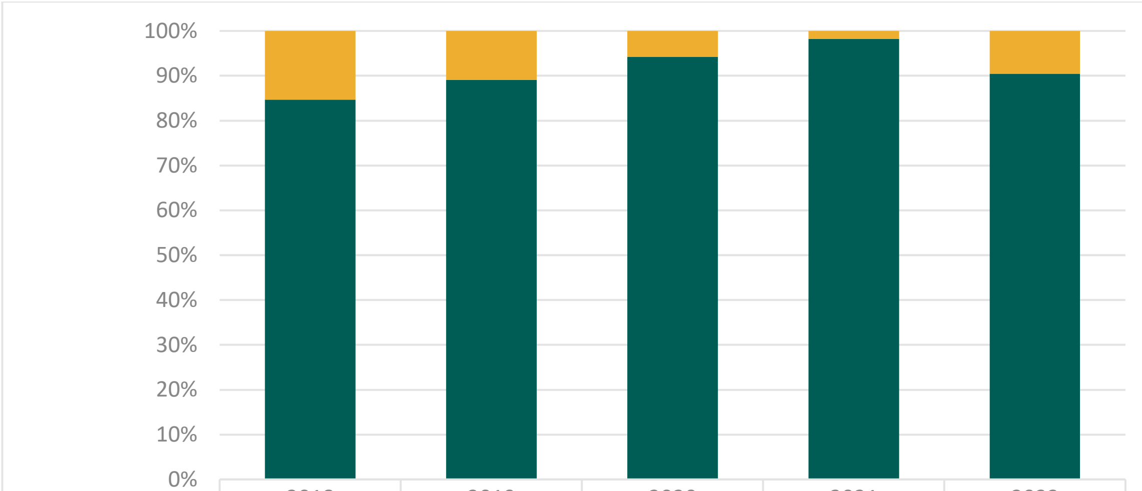


Figure 3: Loss of Supply Impact on Total SAIFI



	2018	2019	2020	2021	2022
Loss of Supply	15%	11%	6%	2%	10%
System	85%	89%	94%	98%	90%

Figure 4: Loss of Supply Impact on Total SAIDI

C2.3 Major Event Days

Major Event is defined by the Institute of Electrical and Electronics Engineers ("IEEE") as "an event that exceeds reasonable design and/or operational limits of the electric power system",[5] where a Major Event Day ("MED") is defined as "a day in which the daily system SAIDI exceeds a Major Event Day threshold value."[5] The term Major Event is similarly defined by the Ontario Energy Board's RRR as "an event that is beyond the control of the distributor and is: unforeseeable, unpredictable, unpreventable, or unavoidable."[6] Similar to LoS events, MEDs are external to routine utility operation, and in addition, are highly volatile from year to year. The exclusion of MEDs and LoS events allows a utility to normalize its reliability data, making it possible to establish meaningful reliability performance trends and associated targets. Toronto Hydro follows the IEEE Standard 1366 Beta Method to derive the MED threshold value for the classification of MEDs.[7] Table 2 lists the MEDs experienced by Toronto Hydro since 2018 and Figure 5 shows the damage resulting from one such event.

[5] IEEE 1366-2022 – IEEE Guide for Electric Power Distribution Reliability Indices. Section 3. Definitions.
[6] Ontario Energy Board, Electricity Reporting and Record Keeping Requirements, Section 2.1.4.2(4) (Effective March 8, 2023).
[7] IEEE 1366-2022 – IEEE Guide for Electric Power Distribution Reliability Indices. Section 4.5 Major Event Day Classification.

Table 2: Major Event Days

Dates	Description	Number of Outages	Total Customers Interrupted	Total Customer Hours Interrupted
April 4, 2018	Wind Storm	68	97,378	112,230
April 15, 2018	Freezing Rain	47	85,281	164,214
May 4, 2018	Wind Storm	98	164,261	800,390
June 13, 2018	Wind Storm	31	35,366	96,504
July 28, 2018	Loss of Supply to Finch TS	22	45,475	192,195
July 8, 2020	Wind Storm	41	54,253	97,477
May 21, 2022	Wind Storm	92	145,313	469,876

Figure 5: Post-Fire Damage at Finch Transformer Station Months Following a Major Event Day

Figures 6 and 7, below, demonstrate the SAIFI and SAIDI system impacts resulting from MEDs.

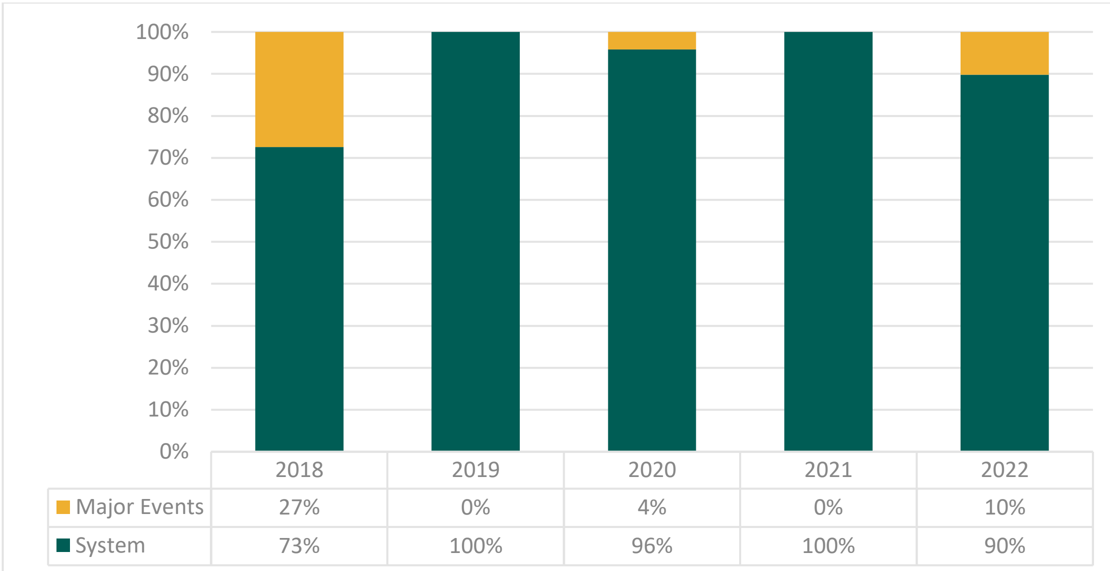


Figure 6: Major Event Days Impact on Total SAIFI

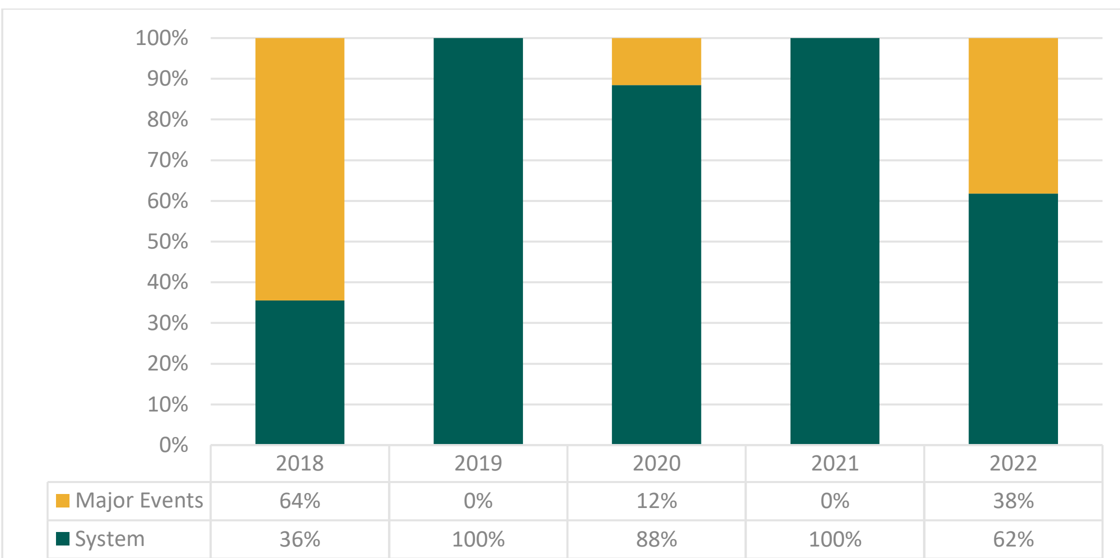


Figure 7: Major Event Days Impact on Total SAIDI

C2.4 Scheduled Outages

Scheduled outages are associated with construction and preventative maintenance activities. Assets that are at risk of failing in the near future may be taken out of service to be repaired or replaced. While this can lead to lengthy outages, the duration of the outage would generally be much shorter than those caused by the asset failing while in-service. These planned replacements are also often required to mitigate safety risks to Toronto Hydro's employees and third-party contractors. Toronto Hydro provides customers advanced notification of any impeding work prior to executing the project, which gives them the opportunity to plan their activities around the repair work. Figures 8 and 9, below, demonstrate the SAIFI and SAIDI system impacts resulting from Scheduled Outages.

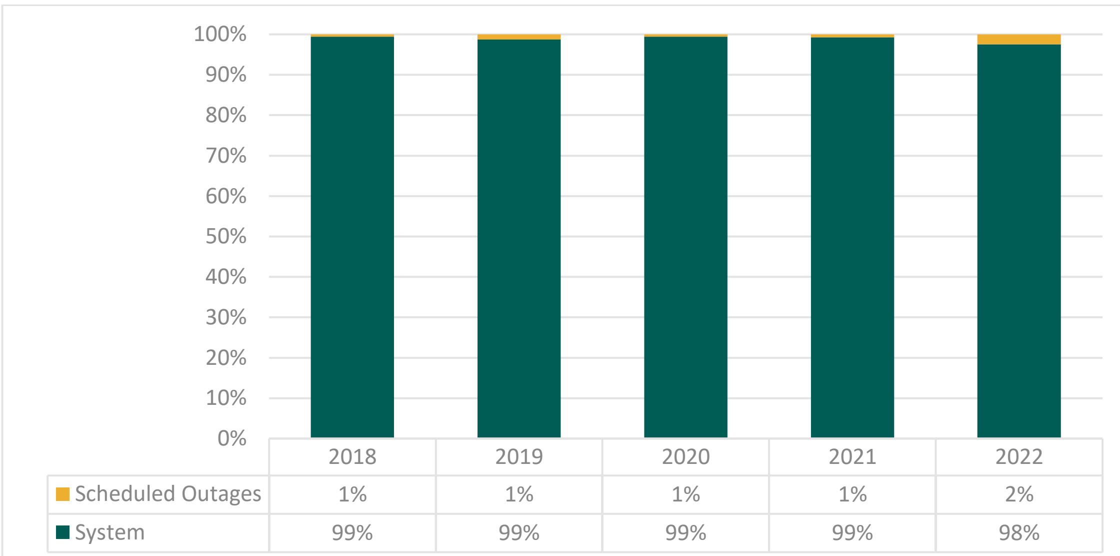


Figure 8: Scheduled Outages Impact on Total SAIFI

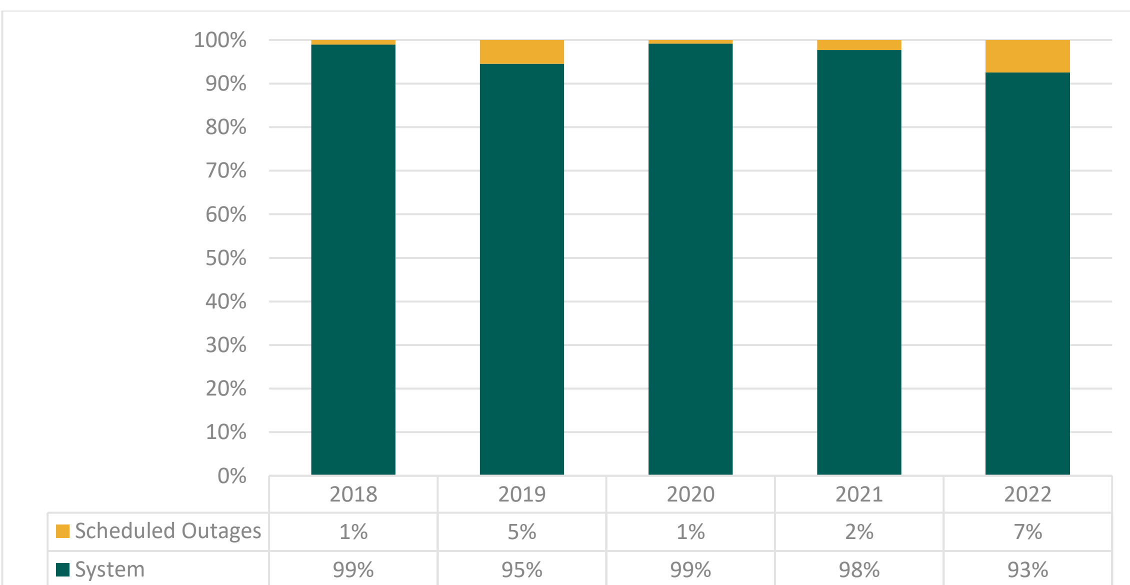


Figure 9: Scheduled Outages Impact on Total SAIDI

C2.5 System Reliability Excluding Loss of Supply, Major Event Days, and Scheduled Outages

As noted above, MEDs and LoS events are outside the utility's control. As a result, these factors are typically excluded from analysis of the overall system performance. In addition, scheduled outages are required to allow certain work to be completed on the distribution system such as replacing assets that are at their end of life or in deteriorated condition to prevent a future outage. The inclusion of scheduled outages in reliability analysis would not provide a true reflection of underlying distribution system performance. Figures 10 and 11, below, show the adjusted SAIFI and SAIDI (excluding LoS, MEDs, and scheduled outages).

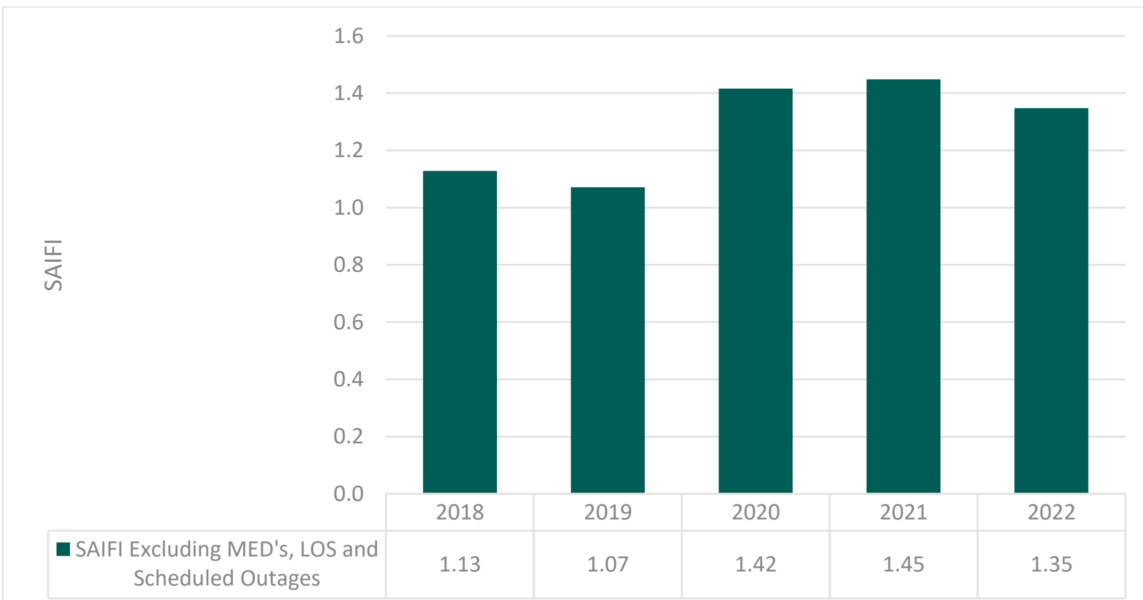


Figure 10: System SAIFI Excluding MEDs, Loss of Supply, and Scheduled Outages

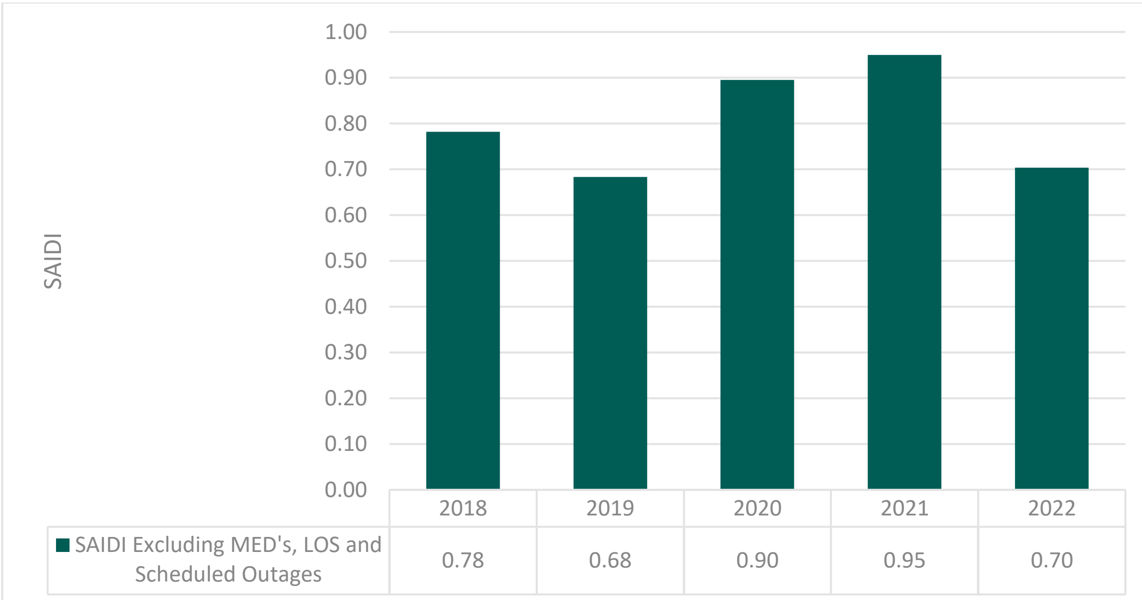


Figure 11: System SAIDI Excluding MEDs, Loss of Supply, and Scheduled Outages

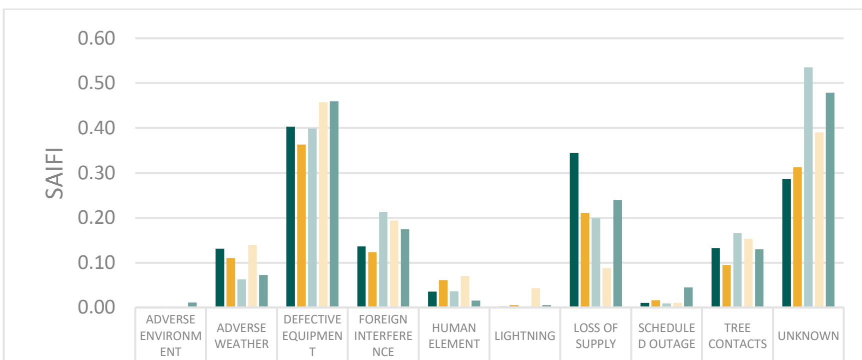
The year-over-year adjusted values show that SAIFI has increased in 2020-2022 compared to 2018-2019 levels, while SAIDI showed a temporary uptick in 2020 and 2021, but decreased back down again in 2022. This recent rise in reliability impacts was caused by a range of factors. The predominant cause for the increase in SAIFI was unknown impacts, which consist of outages that have no apparent cause. However, outages caused by foreign interference (especially animal contacts), defective equipment (including outages attributed to underground cable and cable accessories, overhead switches, overhead conductors, as well as poles and pole hardware failures), and Tree Contacts have also contributed to the overall increase in SAIFI observed during the same period, albeit to a lesser extent.

Similarly, foreign interference (including outages attributed to animal contacts, vehicles, and foreign objects) was the main contributor to the increase in SAIDI during the aforementioned period. Along with foreign interference, defective equipment (particularly underground cable and cable accessories, and overhead switch failures), unknown impacts, and tree contacts have also played a role in the observed increase in SAIDI.

The following sections provide breakdowns by cause code and more detailed discussions of trends within different cause codes and how they are impacted by Toronto Hydro's investments. More generally, Toronto Hydro's core sustainment programs[8] mainly contribute to mitigating the probability of outages due to defective equipment by proactively replacing deteriorating assets at higher risk of failure. The utility's modernization investments serve to improve reliability by reducing the customers impacted and duration of outages due to all causes – for more information on these investments, please see the System Enhancements and Network Condition Monitoring programs[9] and Toronto Hydro's Grid Modernization Road Map.[10] Some programs, such as Area Conversions,[11] contribute to reducing both the probability and length of outages by renewing aging, deteriorating, and obsolete areas of the distribution system, which are at higher risk of failure and take more time to restore power in the event of an outage.

C2.6 Cause Code Analysis

Toronto Hydro tracks causes of service interruptions using the ten primary cause codes as specified in the Ontario Energy Board's RRR.[12] Figures 12 and 13, below, show the utility's 2018-2022 SAIFI and SAIDI performance by cause code. Table 3, below, shows the percentage contribution of each cause code to overall system SAIFI and SAIDI (excluding MEDs).



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2018	0.00	0.13	0.40	0.14	0.04	0.00	0.34	0.01	0.13	0.29
2019	0.00	0.11	0.36	0.12	0.06	0.01	0.21	0.02	0.10	0.31
2020	0.00	0.06	0.40	0.21	0.04	0.00	0.20	0.01	0.17	0.54
2021	0.00	0.14	0.46	0.19	0.07	0.04	0.09	0.01	0.15	0.39
2022	0.01	0.07	0.46	0.17	0.02	0.01	0.24	0.04	0.13	0.48

Figure 12: SAIFI Cause Code Breakdown (Excluding MEDs)

[8] E.g. Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Overhead System Renewal (Exhibit 2B, Section E6.5.
[9] Exhibit 2B, Section E7.1 and E7.3.
[10] Exhibit 2B, Section D5.
[11] Exhibit 2B, Section E6.1
[12] Ontario Energy Board, Electricity Reporting and Record Keeping Requirements, Section 2.1.4.2.5 - Reporting Cause Codes. (Effective March 8, 2023).

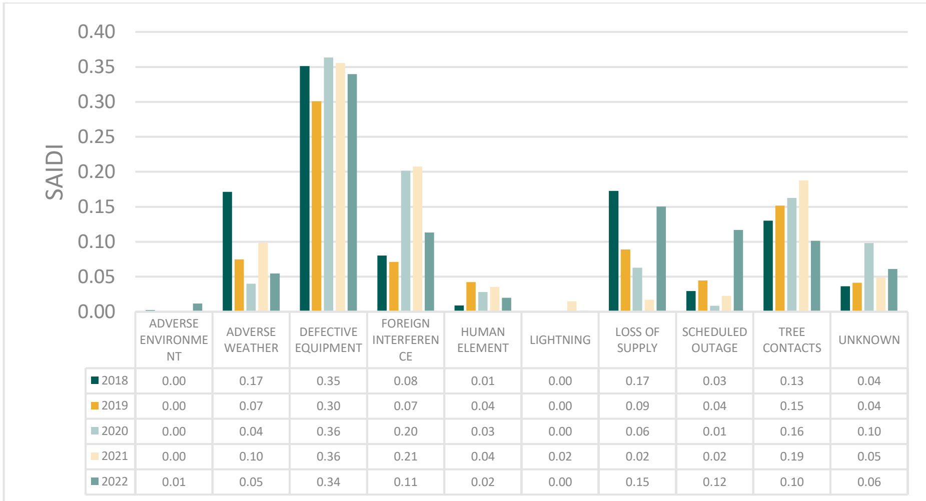


Figure 13: SAIDI Cause Code Breakdown (Excluding MEDs)

Table 3: Five-Year Average SAIFI and SAIDI Contribution by Cause Code (Excluding MEDs)

Cause Code	Contribution % to SAIFI	Contribution % to SAIDI
DEFECTIVE EQUIPMENT	27.5%	36.2%
UNKNOWN	26.4%	6.1%
LOSS OF SUPPLY†	14.3%	10.4%
FOREIGN INTERFERENCE	11.1%	14.3%
TREE CONTACTS	8.9%	15.5%
ADVERSE WEATHER	6.8%	9.3%
HUMAN ELEMENT	2.9%	2.9%
SCHEDULED OUTAGE‡	1.2%	4.7%
LIGHTNING	0.8%	0.4%
ADVERSE ENVIRONMENT	0.2%	0.3%

† Excluded when evaluating Toronto Hydro's system reliability performance under Scenarios 2, 4, and 5.

‡ Excluded when evaluating Toronto Hydro's system reliability performance under Scenario 5.

On average, between 2018 and 2022, defective equipment was the main contributor to SAIFI and SAIDI, at 27.5 percent and 36.2 percent respectively. However, in 2020 and 2022, defective equipment was surpassed by unknown caused outages as the top contributor to SAIFI. As shown in Figures 12 and 13, above, the majority of improvement in 2022 SAIFI and SAIDI results relative to prior years was with respect to adverse Weather, foreign interference, and tree contacts. Toronto Hydro views the defective equipment cause code as a primary indicator of the condition of its distribution system and tracks the cause code as a measure of the effectiveness of its capital expenditure and maintenance investments. Additional analysis of certain cause codes is provided below. Tables 4-6 below also provide the number of interruptions, customer interruptions ("CI"), and customer hours interrupted ("CHI") by cause code (excluding MEDs).

Table 4: Number of Interruptions by Cause Code (Excluding MEDs)

Cause Code	2018	2019	2020	2021	2022
Adverse Environment	8	1	4	3	17
Adverse Weather	129	57	49	79	80
Defective Equipment	441	330	334	364	484
Foreign Interference	144	123	151	169	212
Human Element	19	24	23	38	31
Lightning	4	3	2	22	5
Loss of Supply	34	21	18	10	42
Scheduled Outage	143	102	137	142	907
Tree Contacts	81	48	70	104	120
Unknown/Other	135	135	224	145	233
Grand Total	1,138	844	1,012	1,076	2,131

Table 5: Number of Customer Interruptions by Cause Code (Excluding MEDs)

Cause Code	2018	2019	2020	2021	2022
Adverse Environment	988	5	2,164	249	8,786
Adverse Weather	100,462	84,803	48,318	108,474	56,744
Defective Equipment	308,064	279,474	308,633	354,985	359,936
Foreign Interference	103,812	94,716	165,199	150,885	136,878
Human Element	26,929	47,271	27,811	54,623	12,029
Lightning	1,738	4,346	273	33,840	4,151
Loss of Supply	263,344	162,433	153,684	68,259	187,464
Scheduled Outage	7,993	12,452	6,897	8,398	35,004
Tree Contacts	101,329	73,108	128,667	118,879	101,713
Unknown/Other	218,398	240,491	414,343	303,457	374,813
Grand Total	1,133,057	999,099	1,255,989	1,202,049	1,277,518

Table 6: Number of Customer Hours Interrupted by Cause Code (Excluding MEDs)

Cause Code	2018	2019	2020	2021	2022
Adverse Environment	1,664	9	116	420	9,353
Adverse Weather	131,115	57,672	30,890	76,673	42,846
Defective Equipment	268,452	231,449	281,347	276,297	265,983
Foreign Interference	61,487	54,799	155,980	161,211	88,595
Human Element	6,836	32,542	21,656	27,607	15,633
Lightning	346	601	630	11,684	914
Loss of Supply	131,949	68,436	48,574	13,329	117,641
Scheduled Outage	22,465	34,377	6,770	17,662	91,633
Tree Contacts	99,505	116,665	125,859	146,037	79,471
Unknown/Other	27,880	31,812	75,791	38,041	48,000
Grand Total	751,700	628,362	747,611	768,962	760,069

C2.7 Weather Impacts

The following three cause codes can generally be combined to provide a more accurate reflection of weather impacts on the system:

1. Adverse Weather,
2. Lightning, and
3. Tree Contacts.

Figures 14 and 15, below, illustrate the cumulative weather reliability impacts on the system.

Figure 14: Weather Impacts to SAIFI (Excluding MEDs)

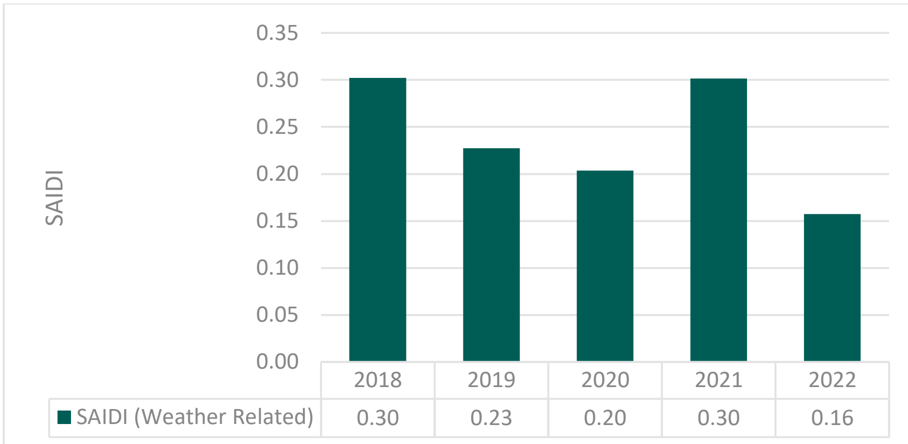
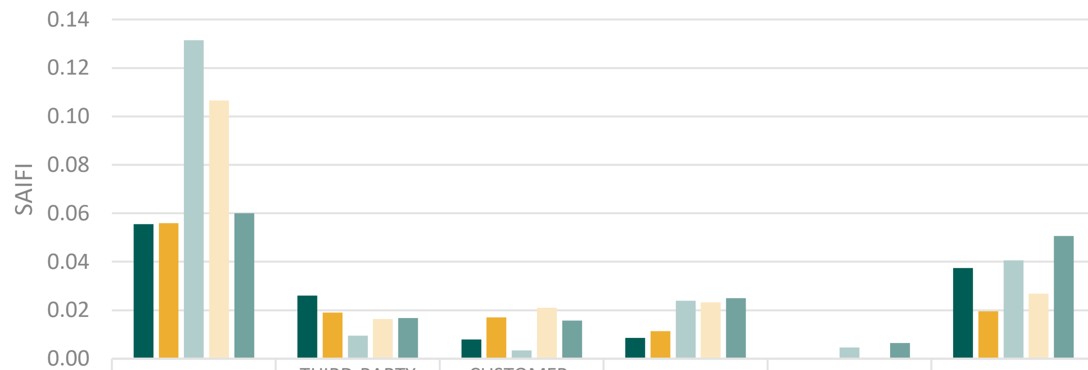


Figure 15: Weather Impacts to SAIDI (Excluding MEDs)

Weather impacts on the distribution system account for a significant portion of system SAIFI and SAIDI. For instance, in 2021 weather-related causes contributed 21.7 percent of the annual SAIFI and 30.5 percent of the annual SAIDI results (excluding MEDs). While in 2022, weather-related causes contributed 12.7 percent of the annual SAIFI and 16.2 percent of the annual SAIDI results (excluding MEDs). Figures 14 and 15, above, demonstrate that a large portion of the SAIFI and SAIDI improvements in 2022 can be attributed to relatively favorable weather conditions that year.

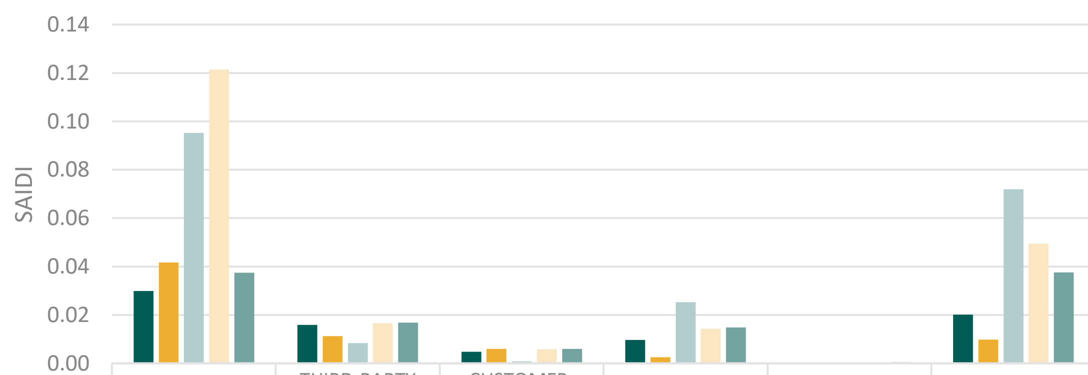
C2.8 Foreign Interference Impacts

Foreign interference consists of outages caused by animal contact, vehicles, foreign objects, third-party interference and dig-ins, customer-owned equipment, and members of the public. Although there are different ways to mitigate foreign interference, such as installing animal guards or moving assets to more secure locations, yearly performance is generally volatile and largely attributable to single isolated events. Figures 16 and 17, below, show the impacts of foreign interference on Toronto Hydro's distribution system.



	ANIMALS	THIRD-PARTY INTERFERENCE & DIG-INS	CUSTOMER-OWNED EQUIPMENT	FOREIGN OBJECTS	MEMBER OF PUBLIC	VEHICLE
2018	0.06	0.03	0.01	0.01	0.00	0.04
2019	0.06	0.02	0.02	0.01	0.00	0.02
2020	0.13	0.01	0.00	0.02	0.00	0.04
2021	0.11	0.02	0.02	0.02	0.00	0.03
2022	0.06	0.02	0.02	0.03	0.01	0.05

Figure 16: Foreign Interference – Root Cause SAIFI (Excluding MEDs)



	ANIMALS	THIRD-PARTY INTERFERENCE & DIG-INS	CUSTOMER-OWNED EQUIPMENT	FOREIGN OBJECTS	MEMBER OF PUBLIC	VEHICLE
2018	0.03	0.02	0.00	0.01	0.00	0.02
2019	0.04	0.01	0.01	0.00	0.00	0.01
2020	0.10	0.01	0.00	0.03	0.00	0.07
2021	0.12	0.02	0.01	0.01	0.00	0.05
2022	0.04	0.02	0.01	0.01	0.00	0.04

Figure 17: Foreign Interference – Root Cause SAIDI (Excluding MEDs)

Of the six sub-categories of foreign interference shown in Figures 16 and 17, above, animal contact is one of the more “controllable” factors, in that Toronto Hydro is able to install reasonable measures to effectively mitigate this risk. More specifically, Toronto Hydro's capital programs include installing new animal guards as part of the overhead renewal program (see the Overhead System Renewal program, Exhibit 2B, Section E6.5), and conducting spot mitigation activity as part of the Worst Performing Feeder ("WPF") program (see the Reactive and Corrective Capital program Exhibit 2B, Section E6.7). Animal guards serve to eliminate a physical point of contact with live equipment and insulate all critical components.

The category of third-party interference and dig-ins, where third parties such as other utilities or contractors have interfered with Toronto Hydro's equipment by digging into the ground, causing a fault, has shown improvement. To improve reliability and public safety, Toronto Hydro's continues to install new TRXLPE cable in concrete-encased ducts instead of burying cable directly into the soil. This approach protects the cable from dig-ins, reducing the risk of damage and improving public safety (refer to Exhibit 2B, Section E6.2 Underground System Renewal – Horseshoe program).

In general, the foreign interference categories mentioned above are volatile and usually beyond Toronto Hydro's control. For instance, the number of animal contacts was similar in 2020 and 2021, with 101 and 104 events respectively, and slightly increased to 116 events in 2022. However, the impact of these animal contacts on SAIFI and SAIDI varied significantly over the years, as shown in Figures 16 and 17.

C2.9 Unknown Impacts

Unknown impacts consist of outages that have no apparent cause, where power is restored by simply closing a circuit breaker or replacing a fuse. As shown by Figures 18 and 19, below, unknown impacts have increased since 2018 in terms of SAIFI and SAIDI. Toronto Hydro leverages short interval control measures for the identification and mitigation of unknown events. This includes but is not limited to performing fault localization analysis as part of an effort to identify problematic areas where past faults may have occurred in the distribution system. Targeted feeder patrols based on these fault localization results are conducted under the Corrective Maintenance program (see Exhibit 4, Tab 2, Schedule 4). The insights garnered from feeder patrols also aid in the identification of near-term corrective actions, as part of the Worst Performing Feeder program (see the Reactive and Corrective Capital program Exhibit 2B, Section E6.7). Although Toronto Hydro makes best efforts to investigate these events, it is not always possible to pinpoint the exact cause.

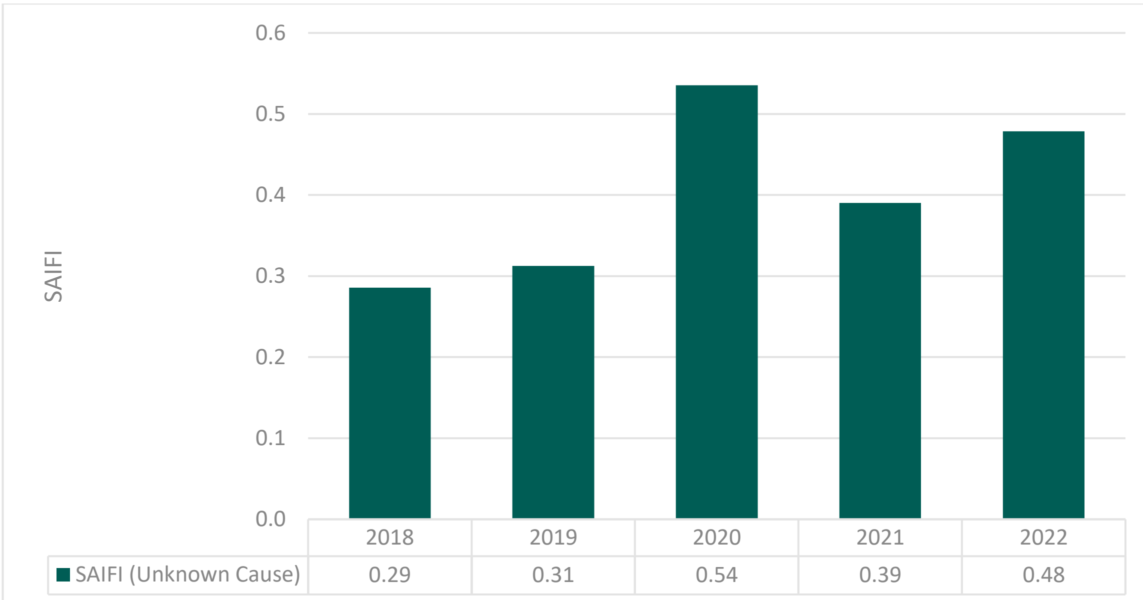


Figure 18: Unknown Impacts to SAIFI (Excluding MEDs)

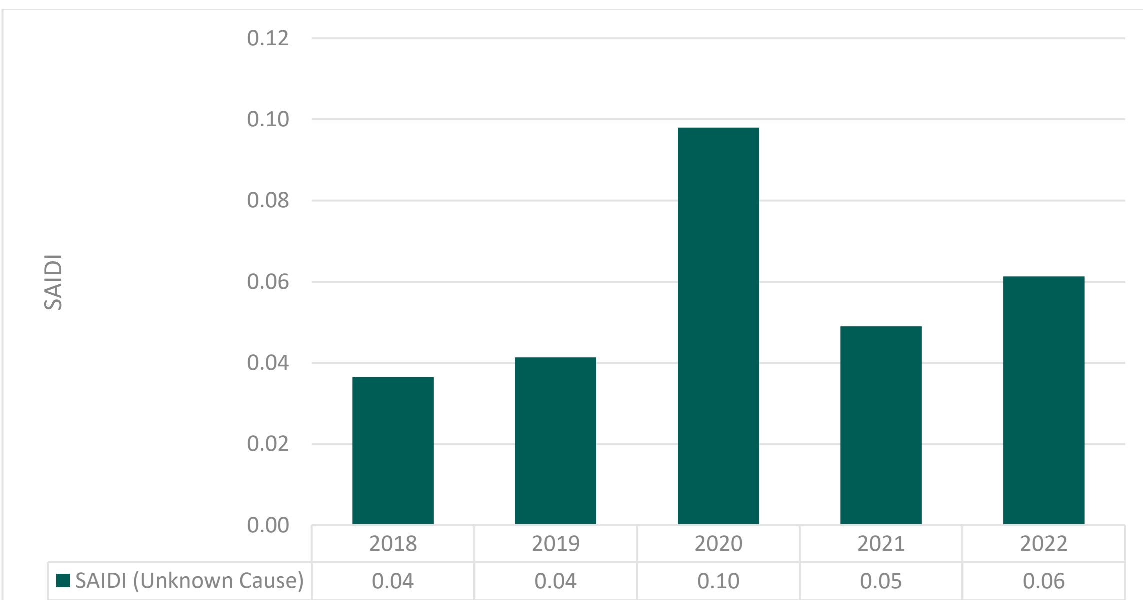
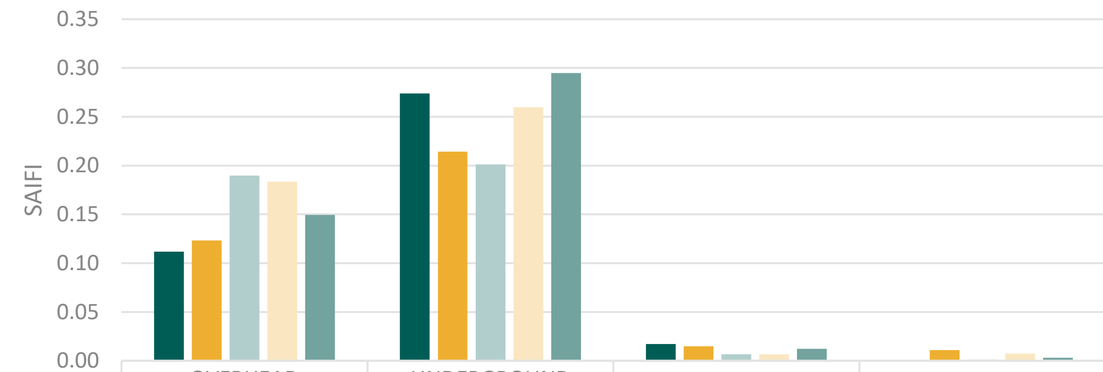


Figure 19: Unknown Impacts to SAIDI (Excluding MEDs)

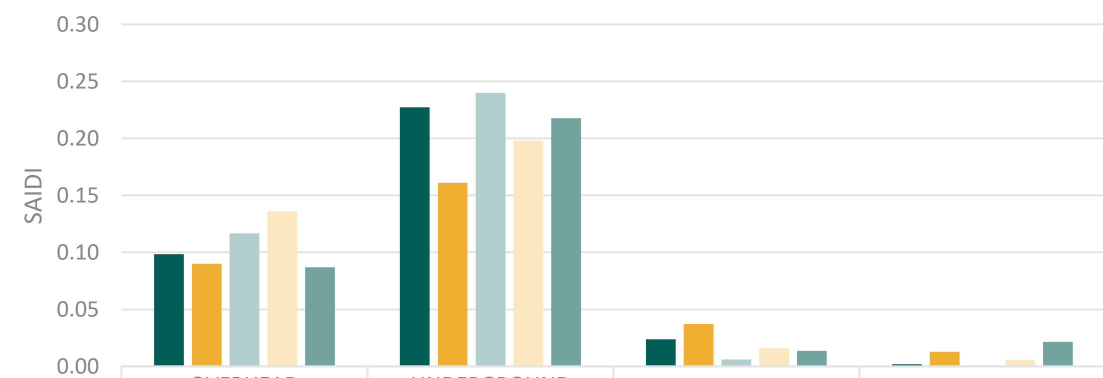
C2.10 Defective Equipment Impacts

As shown in Figures 20 and 21, below, during the 2020-2022 period the contribution of defective overhead and underground equipment to Toronto Hydro's SAIFI has shown a rising trend. While the contribution of overhead and underground equipment to Toronto Hydro's SAIDI has shown a generally stable trend with year-to-year variation.



	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	VARIOUS
2018	0.11	0.27	0.02	0.00
2019	0.12	0.21	0.01	0.01
2020	0.19	0.20	0.01	0.00
2021	0.18	0.26	0.01	0.01
2022	0.15	0.29	0.01	0.00

Figure 20: Defective Equipment SAIFI (Excluding MEDs)



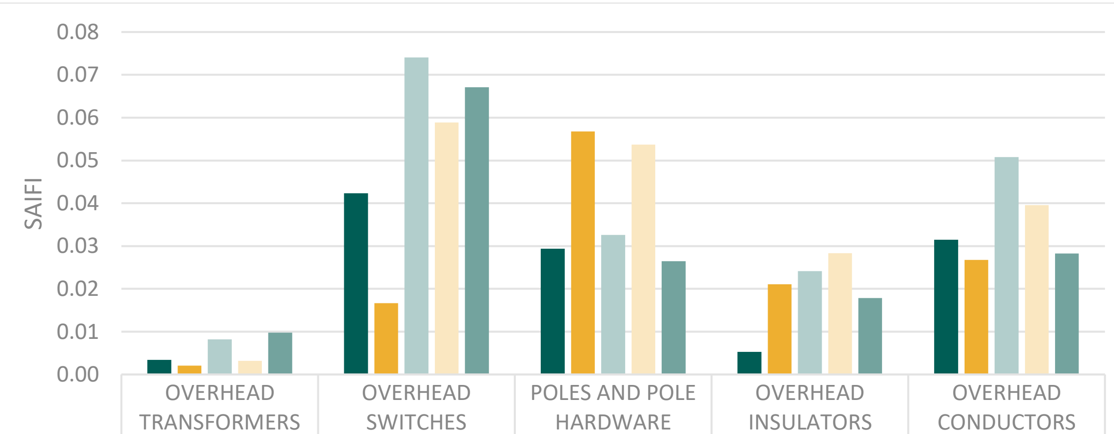
	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	VARIOUS
2018	0.10	0.23	0.02	0.00
2019	0.09	0.16	0.04	0.01
2020	0.12	0.24	0.01	0.00
2021	0.14	0.20	0.02	0.01
2022	0.09	0.22	0.01	0.02

Figure 21: Defective Equipment SAIDI (Excluding MEDs)

C2.10.1 Overhead Defective Equipment

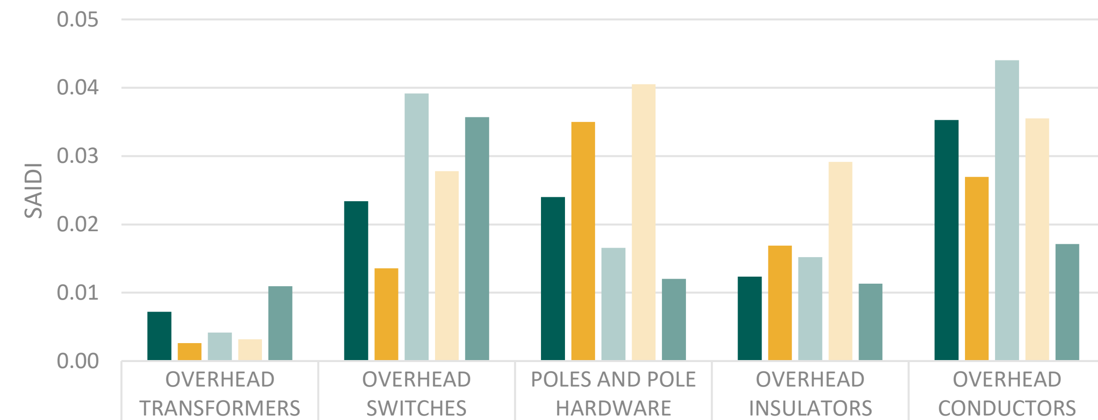
As shown by the Overhead Defective Equipment categories in Figures 22 and 23 below, the most significant SAIFI and SAIDI impacts between 2018 and 2022 are attributable to overhead switches, overhead conductors, as well as poles and pole hardware failures. This is mainly due to the magnitude of these types of failures, which often interrupt a large number of customers when they occur.

The rising SAIFI trend across the multiple sub-categories under Overhead Defective Equipment throughout the 2020-2022 period, as shown in Figure 22 below, reflects the recent focus on replacing overhead transformers at risk of containing PCBs and supports the need for continued investment in overhead system assets to maintain overall reliability, as well as to improve performance in poorly performing areas of the overhead distribution system (see Exhibit 2B, Section E6.5 Overhead System Renewal program). Other programs, such as Area Conversions (see Exhibit 2B, Section E6.1), which also renew and relocate overhead assets, have contributed to maintaining reliability on the overhead system and improving reliability in poorly performing areas. To address these trends, Toronto Hydro plans to continue investing in these important system renewal programs throughout the 2025-2029 plan period.



	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OVERHEAD INSULATORS	OVERHEAD CONDUCTORS
2018	0.00	0.04	0.03	0.01	0.03
2019	0.00	0.02	0.06	0.02	0.03
2020	0.01	0.07	0.03	0.02	0.05
2021	0.00	0.06	0.05	0.03	0.04
2022	0.01	0.07	0.03	0.02	0.03

Figure 22: Defective Equipment SAIFI – Overhead (Excluding MEDs)



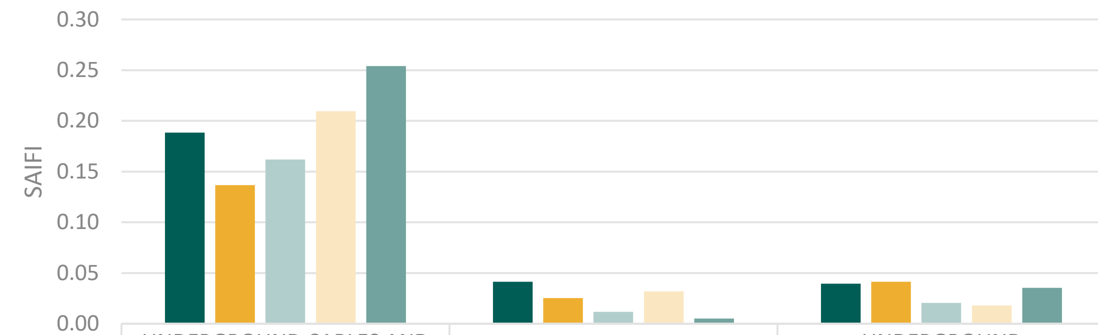
	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OVERHEAD INSULATORS	OVERHEAD CONDUCTORS
2018	0.01	0.02	0.02	0.01	0.04
2019	0.00	0.01	0.03	0.02	0.03
2020	0.00	0.04	0.02	0.02	0.04
2021	0.00	0.03	0.04	0.03	0.04
2022	0.01	0.04	0.01	0.01	0.02

Figure 23: Defective Equipment SAIDI – Overhead (Excluding MEDs)

C2.10.2 Underground Defective Equipment

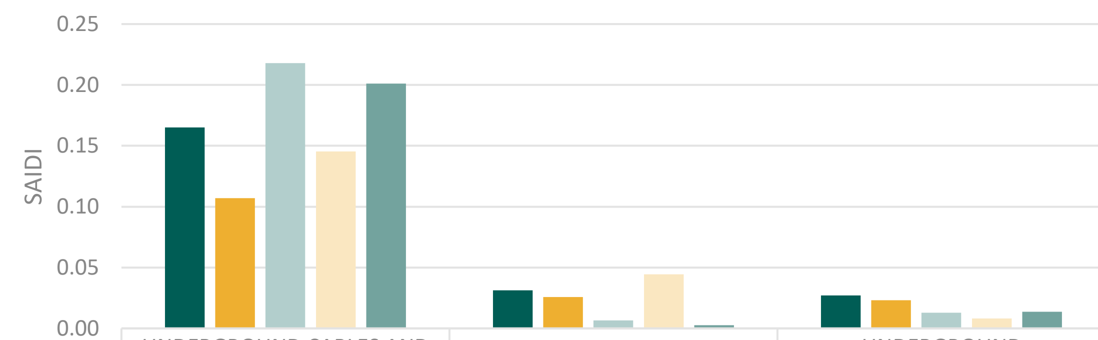
As shown by the underground defective equipment categories in Figures 24 and 25, below, underground cable and cable accessory failures dominate both the SAIFI and SAIDI indices and are the biggest equipment-related causes of interruptions in Toronto Hydro's system. Recently, Toronto Hydro has shifted focus away from rebuild projects to address urgent environmental risk associated with PCBs. However, the continued aging of direct-buried cables and of other types of cables that are reaching end of life are resulting in higher impacts for underground cable and cable accessory failures. This supports the need to refocus on investing in replacing cables that are past useful life, particularly high risk direct-buried cable, as detailed in the Underground System Renewal – Horseshoe program (see Exhibit 2B, Section E6.2), as well as performing cable diagnostic testing to improve the assessment of underground cables and cable accessories (see Exhibit 4, Tab 2, Schedule 2: Preventative and Predictive Underground Line Maintenance).

Despite the increasing trend of underground cable and cable accessory failures, the overall SAIDI trend for underground defective equipment remains relatively stable due to a decline in underground switch and transformer failures in recent years.



	UNDERGROUND CABLES AND CABLE ACCESSORIES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS
2018	0.19	0.04	0.04
2019	0.14	0.03	0.04
2020	0.16	0.01	0.02
2021	0.21	0.03	0.02
2022	0.25	0.01	0.04

Figure 24: Defective Equipment SAIFI – Underground (Excluding MEDs)



	UNDERGROUND CABLES AND CABLE ACCESSORIES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS
2018	0.17	0.03	0.03
2019	0.11	0.03	0.02
2020	0.22	0.01	0.01
2021	0.15	0.04	0.01
2022	0.20	0.00	0.01

Figure 25: Defective Equipment SAIDI – Underground (Excluding MEDs)