E1 Capital Expenditure Plan Introduction

Section E consists of the following sections that details Toronto Hydro's 2025-2029 Capital Expenditure Plan:

- **Section E1 – Capital Expenditure Plan Introduction:** Provides basic information about the expenditure plan, including drivers and expenditures by category.
- **Section E2 – Capital Expenditure Planning Process Overview:** Provides a detailed explanation of the business planning process, including customer engagement, that Toronto Hydro undertook to develop the 2025-2029 Capital Expenditure Plan.
- **Section E3 – System Capability Assessment for Generation Connections:** Provides information on the capability of Toronto Hydro's distribution system to accommodate renewable energy generation ("REG") and other distributed energy resource ("DER") connections.
- **Section E4 – Capital Expenditure Summary:** Provides a comprehensive summary of Toronto Hydro's capital expenditures over the current 2020-2024 and future 2025-2029 rate periods, including explanatory notes on material variances.
- **Sections E5-E8:** Provides detailed, program-specific justifications and business cases for Toronto Hydro's capital expenditure plan in each of the System Access (E5), System Renewal (E6), System Service (E7), and General Plant (E8) categories.

The following is an introduction to the 2025-2029 Capital Expenditure Plan.

E1.1 2025-2029 Capital Expenditures

Toronto Hydro's capital programs are presented according to the Ontario Energy Board's ("OEB") Chapter 5 Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022):

- System Access Investments (Section E5);
- System Renewal Investments (Section E6);
- System Service Investments (Section E7); and
- General Plant Investments (Section E8).

In the current rate period, Toronto Hydro's operating parameters shifted from a relatively linear and stable environment to a more dynamic growth-oriented context, predicated on increases in future customer demand driven by an unprecedented energy transition that is creating new and expanded roles for electricity within the economy. In recognition of this evolving landscape, and customers' needs and priorities for the upcoming planning period, Toronto Hydro adopted four focus areas to structure and guide its planning process for 2025-2029, as further described in Section E2:

- **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.
- **Modernization:** Developing advanced technological and operational capabilities that enhance value and make the system better and more efficient over time.
- **Growth and City Electrification:** Necessary investments to connect customers (including DERs) and build the capacity to serve a growing and electrified local economy.
- **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 ease of reference Table 1 below provides a program and segment concordance between these areas of focus and the OEB investment categories per Chapter 5 of the OEB's Filing Requirements.

Table 1: Program & Segment Concordance to OEB Investment Category

OEB Investment Category	Capital Program	Segments	Concordance to Focus Areas
System Access	**Customer and Generation Connections**	Load Connections	Growth
		Generation Connections	Growth
	Externally Initiated Plant Relocations & Expansions	Externally Initiated Plant Relocations & Expansions	Growth
	Load Demand	Load Demand	Growth
	Metering	Revenue Metering Compliance	Modernization
		Wholesale Metering Compliance	Modernization
	Generation Protection, Monitoring, and Control	Generation Protection, Monitoring, and Control	Growth
System Renewal	**Area Conversions**	Rear Lot Conversion	Sustainment
		Box Construction Conversion	Sustainment
	Underground System Renewal - Horseshoe	Underground System Renewal - Horseshoe	Sustainment
		Cable Chamber Renewal	Sustainment

OEB Investment Category	Capital Program	Segments	Concordance to Focus Areas
	Underground System Renewal - Downtown	Underground Cable Renewal	Sustainment
		Underground Residential Distribution Renewal	Sustainment
		Underground Switchgear Renewal	Sustainment
	Network System Renewal	Network Unit Renewal	Sustainment
		Network Vault Renewal	Sustainment
		Network Circuit Reconfiguration	Sustainment
	Overhead System Renewal	Overhead Infrastructure Resiliency Improvement	Modernization
		Overhead System Renewal	Sustainment
	Stations Renewal	Transformer Stations	Sustainment
		Municipal Stations	Sustainment
		Control & Monitoring	Modernization
		Battery & Ancillary Systems	Sustainment
	Reactive and Corrective Capital	Reactive Capital	Sustainment
		Worst Performing Feeders	Sustainment
System Service	**System Enhancements**	Contingency Enhancement	Modernization
		Downtown Contingency	Modernization
		System Observability	Modernization
	Non-Wires Solutions	Energy Storage Systems	Growth
	Network Condition Monitoring and Control	Network Condition Monitoring and Control	Modernization
	Stations Expansion	Downsview TS	Growth
		Hydro One Contributions	Growth
General Plant	**Enterprise Data Centre**	Enterprise Data Centre	General Plant
	Facilities Management and Security	Facilities Management and Security	General Plant
	Fleet and Equipment	Fleet and Equipment	General Plant
	IT/OT Systems	IT Hardware	General Plant
		IT Software	General Plant
		Communication Infrastructure	General Plant

E1.2 Investment by Category

Tables 2 below compares capital expenditures by investment category for the current 2020-2024 period and the future 2025-2029 rate period. Section E4 provides further explanations of the shifts in planned expenditures over the two rate periods.

Table 2: Planned Capital Investment by OEB Investment Category ($ Millions)

Category	Total 2020-2024	Total 2025-2029	Var. ($)	Var. (%)
System Access	630.0	**1,071.7**	441.7	70%
System Renewal	1,458.2	**1,970.3**	512.1	35%
System Service	225.6	**353.0**	127.4	56%
General Plant	418.6	**562.5**	143.9	34%
Other	55.1	**44.3**	(10.8)	(20%)
Total	**2,787.4**	**4,001.8**	**1,214.4**	**44%**

E1.3 Investment by Trigger Drivers

For categorization purposes, each capital program described in Section E5 through E8 is assigned one or more drivers of work, including a single trigger driver (representing the catalyst for the investment) and typically one or more secondary drivers.[1] Programs are allocated to each of the four investment categories in accordance with their trigger drivers. A description of each trigger driver is provided in the table below.

Table 3: Investment Category Trigger Drivers

Category	Driver	Description
System Access	***Customer Service Requests***	• Toronto Hydro strives to connect demand and 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.

[1] The list of capital investment drivers used in this application were developed based on the OEB's example drivers from Chapter 5 of the OEB's Filing Requirements.

Category	Driver	Description
	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 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	• 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

Category	Driver	Description
	Support	maintaining an environment that fosters efficiency and reliability in delivering essential services.

E2 Capital Expenditure Planning Process Overview

Section E2 explains how Toronto Hydro developed its 2025-2029 Capital Expenditure Plan, including the pacing and prioritization decisions that the utility made to balance price and other outcomes that align with customer needs and preferences. This section is organized into the following three areas:

- **Section E2.1** describes the sequence of business planning activities that produced the Capital Expenditure Plan, and provides an overview of the utility's key considerations and decisions during this process.
- **Section E2.2** describes the results of the utility's planning-specific Customer Engagement and how Toronto Hydro developed a plan that is aligned with and responsive to customer needs, preferences and priorities.
- **Section E2.3** focuses on the outputs of Toronto Hydro's asset management and operational planning processes (described in Section D) and how they influenced the pacing and prioritization of the capital expenditure plan.
- **Section E2.4** focuses on how the outputs of the Asset Needs Assessment are used in the Portfolio Planning process to develop program-level expenditure plan proposals to support the utility's asset management outcome objectives.

Detailed justifications for Toronto Hydro's planned capital program expenditures can be found in the sections in E5 through E8 of this Distribution system Plan ("DSP").

E2.1 Business Planning Process

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 Capital Expenditure Plan ("the Plan") is an output of the utility's outcomes-oriented, customer-focused business planning process. The Plan was derived from the utility's distribution system asset management processes and other operational planning activities, including outputs from the Investment Planning & Portfolio Reporting ("IPPR") process described in Sections D1 and D3. Figure 1 below provides a high-level view of the process as it relates to the Capital Expenditure Plan, and the sections that follow provide an overview of how the elements of the process came together to generate the Plan that forms the basis of Toronto Hydro's 2025-2029 DSP.

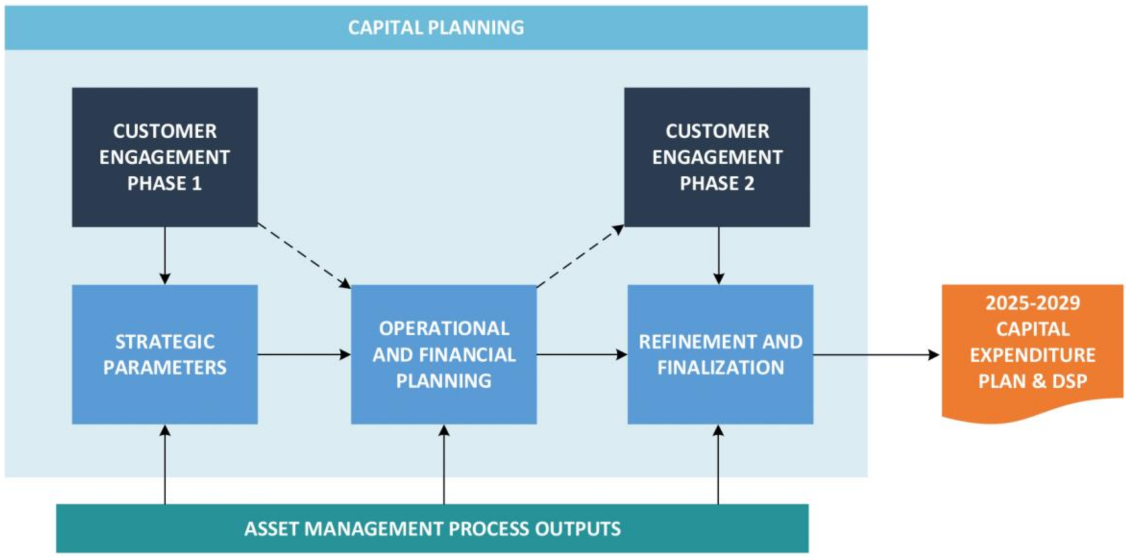

Figure 1: Capital Planning in Business Planning

E2.1.1 Strategic Planning Direction

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.

Feedback from customers was that price, reliability, and investing in new technology were their top 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 customers are more sensitive to power interruptions and prioritize reducing the total number of outages. Almost equally to price and reliability, customers expect the utility to invest in new technology that will reduce costs and make the system better in the future.

Customers also 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 electrification objectives by ensuring that the system has capacity for growth and by providing them advisory services.[1]

With consideration for customers' needs, priorities and other inputs (discussed below), 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 investment priority, Toronto Hydro set performance objectives that provide value for customers and are meaningful to its operations.

Table 1: 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+)

[1] The results of Customer Engagement, Phase 1, are discussed in detail in Exhibit 1B, Tab 5, Schedule 1 – Appendix A.

Investment Priority	Key Performance Objectives
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
General Plant	• Replace critical facilities assets in poor condition • Improve stations site conditions and physical security to meet legislative requirements (Ontario's Building Code [2], *Occupational Health and Safety Act*[3], 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

[2] Ontario Regulation 332/12: Building Code, under Building Code Act, 1992, S.O. 1992, c. 23.
[3] *Occupational Health and Safety Act,* RSO 1990, c. O.1

In addition to setting these performance objectives, Toronto Hydro adopted top-down financial constraints to ensure that the principle of balancing price and service quality outcomes remained top of mind throughout the planning process.

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.[4]
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:

- as mentioned above, customer priorities and preferences identified in Phase 1 of the utility's planning-specific Customer Engagement activities;
- customer needs and preferences as understood by the utility through routine and ongoing engagement with customers and community stakeholders;
- historical and forecast system health demographics and performance;
- long-term asset stewardship needs, including pacing considerations related to resourcing, supply chain, execution constraints, project lead-times, etc.;
- forecasted system use profiles and pressures, including capacity constraints in the short-, medium- and long-term amid increasing demand for load and DER connections;
- detailed demand scenarios reflecting the uncertain long-term trajectory (2050) for the energy system within the City of Toronto;
- safety and environmental risk assessments;
- evolving business conditions and the need to strategically deploy new and enhanced technologies to manage performance risk and take advantage of emerging opportunities to generate value for ratepayers;
- resiliency and business continuity risks, including climate change risk;
- evolving regulatory and compliance needs;
- workforce needs and challenges;
- inflationary cost pressures, including significant upward pressure on material and construction costs in Toronto;
- total cost benchmarking; and

[4] As calculated for the monthly bill of a Residential customer using 750 kWh.

- distributor scorecard benchmarking.

To further inform the selection of price and capital budget limits, Toronto Hydro performed a high-level scenario analysis based on preliminary investment strategy options for each capital program. These options generally reflected:

- a cost-constrained "low" option that, depending on the type of program (i.e. sustainment, modernization, growth, or general plant), would involve taking on additional asset risk in the medium-term, delaying or forgoing further modernization or decarbonization benefits, or taking a higher-risk "wait-and-see" approach to investing for growth (i.e. expansion and connections);
- a "high" option, which, depending on the program, would aim to improve system performance and asset risk in the medium-term, strategically accelerate modernization in areas that can deliver long-term reliability and efficiency benefits for customers, or plan for higher growth needs driven by electrification and community energy plans; and
- a middle option, where program-specific trade-offs would be made between costs and benefits, for example by aiming to maintain current levels of asset risk for certain asset classes, or stretching the pace of modernization and associated benefits over a longer time horizon.

Figure 2, below, illustrates what the total capital expenditure plan would look like if Toronto Hydro had selected exclusively from either the low or high options for every investment program as compared to the draft plan for 2025-2029.

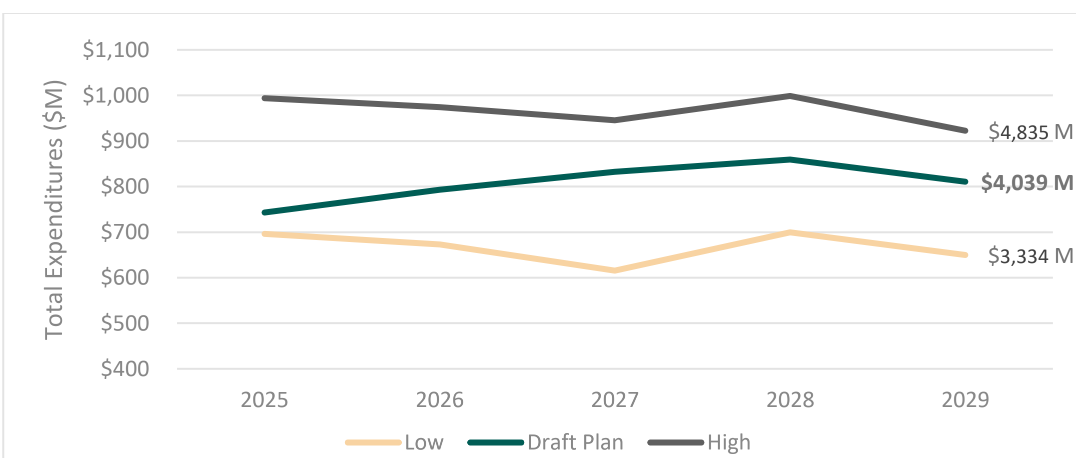

Figure 2: Preliminary High-level 2025-2029 Capital Expenditures Scenarios

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 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.

E2.1.2 Focus on Operational and Financial Planning

The strategic parameters guided the operational and financial planning activities that produced the capital expenditure plan for 2025-2029. Over the course of these iterative planning activities, the utility worked to develop and optimize its program-level capital and operational expenditure plans to align with short- and long-term performance objectives, while remaining within the financial constraints and strategic considerations set-out in the strategic parameters.

The utility developed initial capital program expenditure proposals with the aim of fulfilling strategic objectives in the focus areas of Growth, Sustainment, Modernization and General Plant. From this starting point, an iterative process generated multiple versions of the capital expenditure plan, eventually producing a draft plan that formed the basis of Phase 2 of Customer Engagement. The differences between the initial version of the plan – which on an aggregate basis was higher than the $4,000 upper limit on capital expenditures – and the draft version of the plan were as follows:

- **Growth:** Toronto Hydro reduced Growth proposals for the 2025-2029 period by approximately $191 million. This was largely achieved by taking a more balanced approach to the expected demands placed by electrification and refining forecast estimates in the Customer Connections program. Given the uncertainty surrounding the timing of electrification driven pressures and the energy transition, the utility opted to plan for moderate growth within this rate period while making selective, strategic investments to prepare for further growth in the future. Refinements to program cost and volume estimates also drove minor changes to expenditures within other programs.
- **Sustainment:** Toronto Hydro reduced its Sustainment proposals for the 2025-2029 period by approximately $87 million. It scaled back investments in its Area Conversions program, specifically in the Rear Lot Conversion segment, by approximately $37 million by converting customers with rear lot construction at a more moderate pace in alignment with the Ontario

Energy Board ("OEB's") 2020-2024 Decision and Order.[5] It also reduced investments in the Cable Chamber Renewal segment within its Underground Renewal - Downtown program by approximately $25 million by scaling back the number of poor condition assets addressed in the next rate period and managing failure risk by concentrating on asset locations that carry the highest level of potential failure consequences. Finally, the utility reduced investments in the Underground Renewal – Horseshoe program by approximately $48 million in order to balance reliability and cost pressures, reducing the pace of direct buried cable replacement and feeder conversions within the rate period. These reductions were partly offset by refinements to program estimates within other programs. From the onset, the utility worked to constrain the planned pacing of renewal investment to a minimum level at which it expects it can maintain recent levels of system average reliability (with necessary support from complimentary grid modernization investments), while ensuring prudent management of broader long-term asset risk considerations, including: managing longer-term demographic pressures in certain asset classes; addressing obsolescence risks such as the large remaining population of 4 kV feeders and stations, which are inefficient and poorly suited to meet emerging system demands; and ensuring sufficient funding to support the upsizing of neighbourhood level equipment (e.g. pole top transformers) during renewal projects in order to support electrification of consumer energy demand. A description of how the utility leveraged its asset management processes to appropriately pace and prioritize its Sustainment plan is provided in Sections E2.2 and E2.4 below.

- **Modernization:** Toronto Hydro reduced Modernization expenditures by approximately $191 million over the 2025-2029 period. This reduction was driven by the need to ensure progress towards grid modernization objectives while balancing rate impacts for customers. The reductions were primarily achieved within the System Enhancement program. The Downtown Contingency segment was substantially reduced, focusing efforts in a limited way on creating station switchgear ties between Copeland Station and Esplanade Station within this rate period to manage a subset of contingency concerns within the downtown system. Toronto Hydro expects to pilot innovative solutions such as the Automated Primary Closed Loop distribution system which has the capability to provide a more effective and relatively economical solution to establish feeder ties between stations, thereby delivering longer term system benefits at a reduced cost in the future. Toronto Hydro also reduced the Contingency

[5] EB-2018-0165, Decision and Order (December 19, 2019).

Enhancement segment in order optimize the investment profile of the program over the five years and manage resource and other execution risks. Reductions within the System Enhancement program were slightly offset by refinements to cost and volume estimates within other programs.[6]

- **General Plant:** General Plant expenditures decreased by approximately $11 million as result of adopting a more constrained strategy for the Head Office, as described in the utility's Facilities Asset Management strategy at Section D6.

Overall, in an effort to find the balance between price and progress towards outcomes that customer expect, Toronto Hydro constrained its initial capital plan by approximately $480 million from the beginning to the end of the process. The result was a $4,000 million draft capital expenditure plan for 2025-2029,[7] which was subsequently refined and finalized as described in the next section.

E2.1.3 Refinement and Finalization of the Capital Expenditure Plan

Toronto Hydro presented the draft plan to customers in the Phase 2 Customer Engagement survey to validate whether: (i) the plan aligns with customer needs and priorities and (ii) the balance between price and other outcomes aligns with customer preferences. To that end, the Phase 2 survey solicited customer feedback on Toronto Hydro's overall draft plan and the associated price impacts. 84 percent of customers in all customer classes supported the price increase associated with the draft plan or an accelerated version of it. A full analysis of the Phase 1 and Phase 2 Customer Engagement results is provided in Section E2.3 below.

To gain additional insight into the preferences of customers relative to trade-offs between price and other key outcome like system health, reliability and customer service, Toronto Hydro provided customers with the key details of the utility's investment plan, broken down into seven key investment options (described in Section E2.3 below). For each of these investment options, the utility described its draft plan and options to spend more or less for faster or slower progress towards key performance outcomes. In response to being asked to make specific trade-offs between price and other outcomes in each of the seven choices within the plan, customers expressed certain

[6] Exhibit 2B, Section E7.1.
[7] This figure includes inflation and other allocations, and excludes Renewable Enabling Improvement ("REI") expenditures funded through provincial rate relief.

preferences to increase, maintain or reduce the pace of investment. Toronto Hydro considered this feedback in refining and finalizing its 2025-2029 investment plan.

Along with refining planning assumptions to incorporate new and salient information such as the impact of 2022 actuals, the utility leveraged the results of Customer Engagement Phase 2 to calibrate the pace of investment in certain programs. Overall, the adjustments that Toronto Hydro made to programs between the draft plan and the final plan were as follows:

- **Growth:** Toronto Hydro reduced growth-related expenditures by approximately $57 million over the 2025-2029 period. This was due in part to an additional reduction to the load connections forecast, which was partly offset by increased investment needs identified in the Load Demand program due to incremental scope and revised cost estimates. Toronto Hydro also refined the scope of the Battery Energy Storage Systems segment to reflect insights from the procurement process for battery investments in the current rate period, which resulted in further reductions. In light of customer feedback with respect to trade-offs between price and other outcomes in Growth investments, the utility also reduced the Stations Expansion program by $35 million by deferring the second phase of the Basin TS expansion into the next period.

- **Sustainment:** Toronto Hydro increased Sustainment expenditures by approximately $65 million over the 2025-2029 period due to refinements to program cost estimates including updates for inflationary assumptions and incremental investment needs to address legacy infrastructure and associated failure risk. For example, incremental expenditures were required to address legacy switches in the downtown underground system and to complete all Box Construction feeder conversions in the next rate period. In order to partly offset these increased investment requirements and be responsive to customer preferences gleaned in the Phase 2 engagement, Toronto Hydro reduced $20 million from its stations renewal program by deferring switchgear renewal investments.

- **Modernization:** The Modernization plan increased by $8 million. Increases in the Metering program due to cost refinement and inflation pressures were offset by the decision to reallocate funding for various types of modernization pilot projects to the Innovation Fund outlined in Exhibit 1B, Tab 4.

- **General Plant** General Plant expenditures decreased by approximately $48 million over the 2025-2029 period, the Facilities Management and IT Software programs were reduced by approximately $13 million, and the pace of fleet electrification was lowered by $3.5 million in response to customer preferences expressed through the second phase engagement (see E2.3 below). The remaining decrease is due in large part to an administrative correction made to the Fleet Equipment program that resulted in a $31 million reduction.

Overall, Toronto Hydro reprioritized investments to produce an optimized and customer-aligned capital expenditure plan of $4 billion over the 2025-2029 period.[8]

Section E2.2, below, provides an overview of how Toronto Hydro derived the plan from the asset management processes described in Section D of the DSP. Section E2.3 describes the results of the Customer Engagement process and how they informed the DSP. Section E2.4 focuses on how the outputs of the Asset Needs Assessment are used in the Portfolio Planning process.

E2.2 Asset Management in Capital Planning

Toronto Hydro primarily derived its 2025-2029 Capital Expenditure Plan based on its Asset Management System ("AMS") for distribution assets, Information and Operational Technology ("IT/OT") Asset Management, and Facilities Asset Management described in Section D. As discussed in Sections D1 and D3, the utility develops its system investment programs through the annual Investment Planning and Portfolio Reporting ("IPPR") process. This process leverages the various asset lifecycle optimization and risk management methodologies discussed in Section D3 to produce capital programs and expenditure plans that are optimized to support the utility's customer-focused outcome objectives. The scenarios and recommendations developed in IPPR become inputs to business planning (discussed in the previous section), where program expenditure plan proposals are further refined, leveraging the same AMS tools and outputs.

Figure 3 below (originally presented in Section D3.4) is a simplified view of the major program planning elements within the IPPR process. It depicts the cyclical nature of program development and the integration points with customer engagement activities.

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

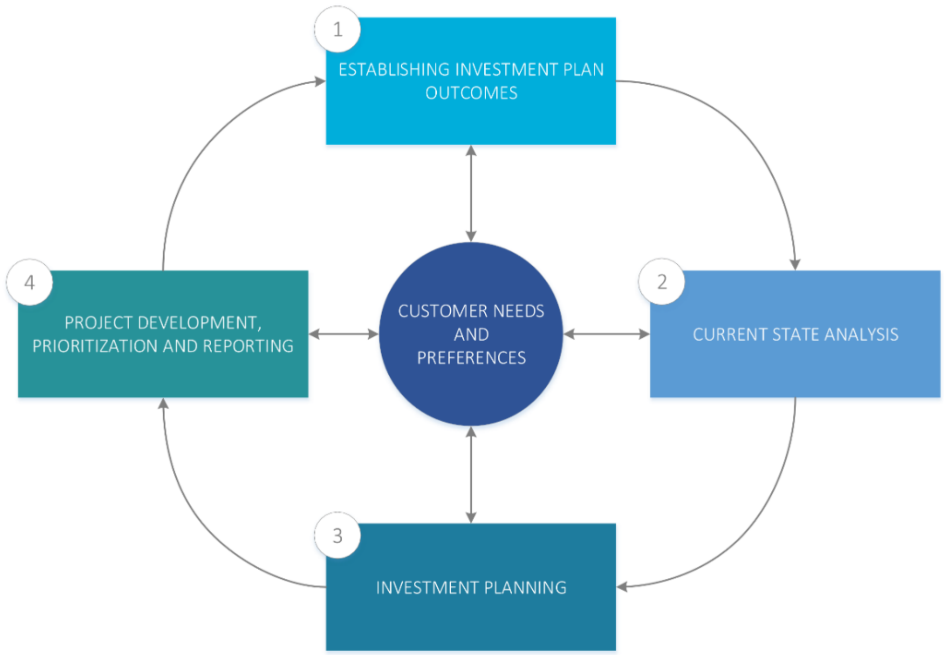

Figure 3: The IPPR Program Development Framework

Step one in the figure above, which involved selecting the desired outcomes and objectives for the 2025-2029 investment plan, was described in the previous section (E2.1). The following sections explain how each of the remaining three elements in this process contributed to the production of the 2025-2029 Capital Expenditure Plan for system-related investments.

E2.2.1 Asset Needs Assessment for 2025-2029

Concurrent with the development of the utility's asset performance objectives (summarized in Table 1 above and also discussed in Section D1.2.1.1), Toronto Hydro performed an Asset Needs Assessment to develop a baseline understanding of the current state of its distribution system. As explained in Section D3, the Asset Needs Assessment includes a Current State Assessment ("CSA") and a System Needs and Challenges Review. The results of these analyses informed the capital budget limit that Toronto Hydro set in the strategic parameters for the business plan.

E2.2.1.1 Current State Analysis Results

The Current State Analysis ("CSA") produced foundational information, including asset demographics (i.e. counts, age and nameplate attributes) and condition demographics. These data points informed program pacing and prioritization decisions throughout business planning.

1. Asset Condition Demographics

The utility examined the current state of its asset condition demographics – derived from its Condition Based Risk Management ("CBRM") methodology – to determine which asset classes were showing the greatest signs of deterioration, and took this into account in establishing planning scenarios. Table 2 below shows the percentage of assets in the worst condition bands (HI4 and HI5) summarized by major system category.

As illustrated by comparing the 2022 Actual condition to 2017 Actual condition, Toronto Hydro managed to improve or approximately maintain the HI4/HI5 condition profiles for major assets on its network and underground systems, as well as within its stations. This was accomplished through sustained capital investment and maintenance activities over the last five years. Over the same period, the utility saw a moderate deterioration in condition on its overhead system, driven largely by deterioration in the wood pole population. As discussed in Section E4.1.2, this decline in overhead system health was driven in part by the decision to restrain renewal expenditures by deferring some work into 2025-2029 in order to balance cost pressures across the overall Capital Expenditure Plan. Toronto Hydro managed this by shifting temporarily to a spot replacement approach focused primarily on PCB removal and delaying larger area rebuilds that are required to address deteriorating poles and switches as well as obsolete 4 kV feeders.[9]

Table 2: CBRM Results by System (% of asset population in HI4/HI5 condition as of year-end)

System Category	2018 CBRM Outputs		2023 CBRM Outputs	
	2017 Actual	2024 Projection (no intervention)	2022 Actual	2029 Projection (no intervention)
Network	5%	23%	4%	16%
Overhead	6%	34%	9%	30%
Stations	8%	44%	3%	28%
Underground	3%	7%	3%	10%

As shown in Table 2 above, Toronto Hydro continues to face asset condition pressures across all parts of its system over the next rate period. For Toronto Hydro's high-volume overhead and underground

[9] Note that Toronto Hydro found that it was necessary to also defer work within the Underground System Renewal – Horseshoe program in favour of PCB at-risk equipment removals. In this case, it has largely been underground cable replacements that the utility has deferred to 2025-2029. Since underground cables do not have a condition model, the effect of cable replacement deferrals on the growing backlog of cables at risk of failure is not captured in Table 2.

asset populations, the rate of asset deterioration expected by the end of the next rate period is projected to be roughly the same as it was in the equivalent analysis performed in 2018. While the network system is exhibiting a slower rate of deterioration compared to 2018, two additional drivers of investment should be noted: (1) the continuing prevalence of non-submersible network units, which are at a higher risk of catastrophic failure due to flooding regardless of their condition; and (2) an anticipated wave of network demographic issues beyond 2029, with over 50 percent of network units projected to be at or beyond end of useful life by 2034 without intervention. As for Toronto Hydro's major stations assets, an observed improvement in the rate of deterioration is the result of the utility's focused effort in recent years to eliminate high risk, obsolete stations assets including oil circuit breakers. Despite these ongoing efforts, the CBRM model projects a 25-percentage-point increase in the share of HI4/HI5 assets for the station asset population by 2029, which equates to hundreds of major stations assets, the vast majority of which are of obsolete technology types.[10]

Toronto Hydro set-out to develop a risk-calibrated plan that would invest the minimum necessary to manage reliability performance in light of condition-related pressures, and prevent the accumulation of a backlog of assets that are at risk of failure or otherwise need to be upgraded. Asset renewal backlogs are problematic not only because they greatly heighten system reliability risk: they also result in rate instability for customers, as well as 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 proactive investment. This was one of the key considerations in the utility's selection of its capital budget limit for business planning. The Portfolio Planning section below (E2.2.3) provides additional details on how asset condition informed the pacing of investment in Toronto Hydro's 2025-2029 Capital Expenditure Plan.

2. Assets Past Useful Life

As discussed in Section D3.2, to assess the age demographics of its distribution system, Toronto Hydro examines the proportion of assets across the system that are operating at or beyond useful life (the Assets Past Useful Life metric, or APUL). The age demographics of the system as of the beginning of 2023 are summarized in Figure 4 below.

[10] For a detailed discussion of the various drivers for the proposed stations renewal pacing, refer to Exhibit 2B, Section E6.6.

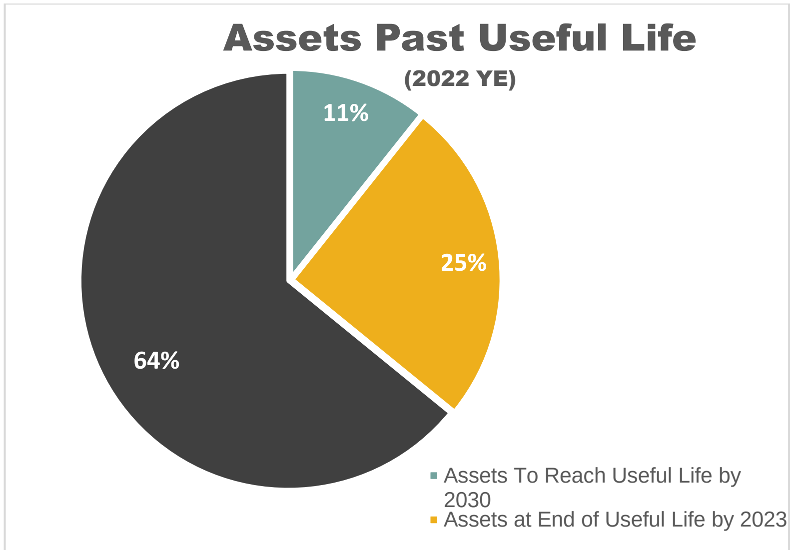

Figure 4: Percentage of Assets Past Useful Life

In 2018, Toronto Hydro's percentage of assets past useful life was 24 percent, with an additional nine percent forecasted to reach expected useful life by 2025. At an aggregate level, and as a direct result of Toronto Hydro's ongoing renewal efforts in recent years, the APUL measure has been relatively stable. However, it should be noted that even a single percentage point in the APUL measure represents future asset replacement needs in the order of hundreds of millions of dollars. Approximately a quarter of the utility's asset base continues to be operating beyond its expected useful life, and an estimated additional 11 percent will reach that point by 2030, which is two percentage points higher than the equivalent rate of deterioration projected in 2018, indicating that a significant proactive renewal program continues to be necessary to sustain overall demographics at current levels and prevent the APUL backlog from increasing.

An overall increase in the APUL backlog would result in a corresponding deterioration in reliability, safety risk, reactive replacement costs, and other outcomes driven by asset failure.

E2.2.1.2 System Needs and Challenges Review

In addition to the information generated by the CSA, Toronto Hydro considered a number of other indicators of system investment need, including system utilization, connection capacity, distributed generation forecasts, legacy asset profiles (e.g. lead cable replacement needs), regional planning considerations, grid modernization objectives, and other factors. The utility developed strategic investment scenarios for each of these issues, which in turn informed the capital expenditure plan scenarios discussed in Section E2.1.

Section D2 provides an overview of the various considerations resulting from the System Needs and Challenges Review. Section D4 describes Toronto Hydro's strategy to manage growth and development in an uncertain future as a result of electrification and decarbonization of the utility grid. It outlines how additional drivers and enhanced scenario-based load forecasting techniques impacted the 2025-2029 investment plans. Section D5 provides a comprehensive overview of the utility's Grid Modernization Strategy for 2025-2029. Section E2.3.3 provides additional insight into the strategies for addressing these issues in the 2025-2029 Capital Expenditure Plan.

E2.2.1.3 System Reliability Performance and Projection Scenarios

System reliability is an important customer-focused outcome and a lagging indicator of performance, including the effectiveness of the subset of Sustainment and Modernization investments that are primarily directed toward preventing outages and shortening outage duration (e.g. direct-buried cable replacement, Contingency Enhancement, etc.). Although Toronto Hydro's renewal and modernization efforts over the last decade have led to improvements in reliability performance that began in the mid-2000s, more recently this performance has plateaued. As shown in Figures 5 and 6, the rate of improvement in frequency and duration of outages began to slow in the last rate period, prior to a slight deterioration in reliability performance experienced from 2020 to 2022.

During the period of 2020-2022, Toronto Hydro experienced a rise in reliability impacts caused by a range of factors. The increase in SAIFI was driven by factors including 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. The largest individual contributor to the increase in SAIFI was Unknown impacts. Unknown outages are typically short-duration, high-impact outages that are restored through SCADA controlled devices. While Toronto Hydro makes its best effort to investigate these events, it is not always possible to pinpoint the exact cause. The majority of these outages are usually non-permanent and self-clearing, stemming from potential causes including animal contacts, tree contacts, and emerging equipment failures.

With respect to SAIDI, Foreign Interference (including outages attributed to animal contacts, vehicles, and foreign objects) was a substantial 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 material role in the observed increase in SAIDI. Further information regarding Toronto Hydro's historical reliability performance is available in Exhibit 2B, Section C.

Starting in January 2022, in an effort to improve reporting accuracy, Toronto Hydro began leveraging Oracle's Network Management System ("NMS") – serving as an upgrade to its existing Outage Management System – as part of its reliability audit process to capture improved outage information and address limitations within the Interruption Tracking Information System ("ITIS"). As part of the multi-year NMS upgrade initiative, Toronto Hydro plans to implement a new commercial software solution, Oracle's Utility Analytics ("OUA"), which will serve as the future successor to ITIS for reliability reporting. Further discussion on the impacts of OUA is provided in Exhibit 2B, Section C.

These upgrades 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 with historical years. This includes an increased number of outages affecting small numbers of customers and a higher number of scheduled outages reported, impacting both SAIFI and SAIDI performance.

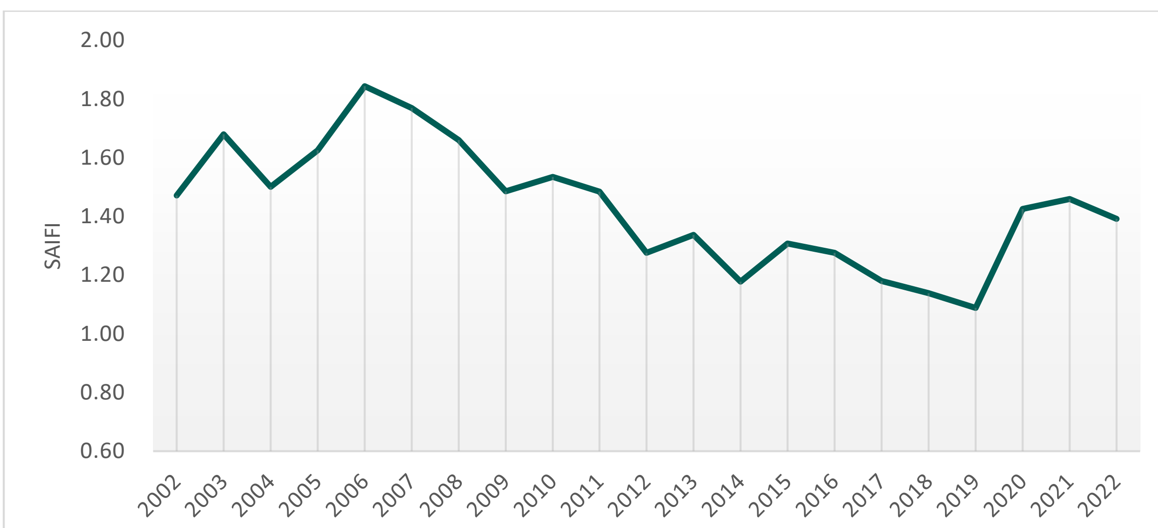

Figure 5: Historical SAIFI (Excluding MEDs and Loss of Supply)

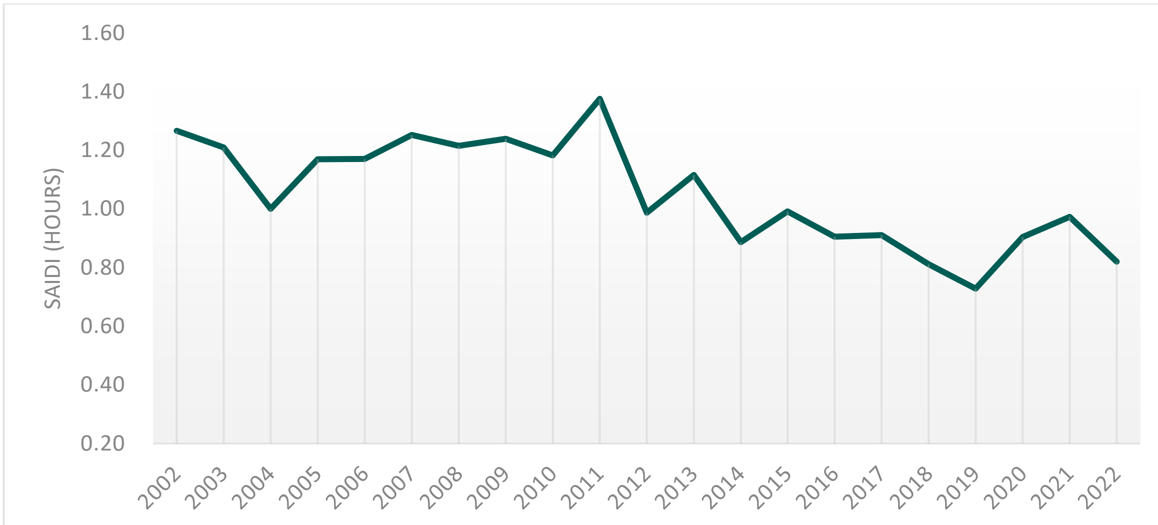

Figure 6: Historical SAIDI (Excluding MEDs and Loss of Supply)

Overall, the utility drew the following key conclusions from recent historical reliability trends and associated asset demographics:

1. **Defective Equipment continues to be the most dominant contributor to reliability performance (SAIDI and SAIFI),** with only Unknown outages having a roughly equivalent impact on SAIFI in the last three years. Asset condition and age demographics are important leading indicators of future Defective Equipment cause code performance. As discussed above (E2.2.2.1), Toronto Hydro's demographic models show that, for the 2023-2029 period, population-level risk accumulation related to asset deterioration will be about as rapid as it was projected to be over the equivalent 2018-2024 period, and in parts of the system where defective equipment has a significant impact on day-to-day reliability (e.g. the underground horseshoe system), the rate of deterioration could in fact be higher. It should be noted that Toronto Hydro's investment plan for the underground and overhead horseshoe systems will continue to be partially skewed toward PCB at-risk equipment replacement activities in 2023, 2024 and 2025, meaning that a full return to primarily reliability-focused sustainment investments will not occur before 2026. With all of these factors in mind, and with the goal of ensuring that sustainment investments are sufficient to maintain reliability over the rate period and the longer-term, the utility concluded that it would be necessary to increase sustainment expenditures in the 2025-2029 period.

2. **General reliability performance has plateaued in recent years following a sustained period of improvement.** From the beginning of the utility's concerted ramp-up in system renewal activities (circa 2007), Toronto Hydro had a focus on eliminating non-standard equipment and system configurations with acute failure risks (e.g. fibre-top network units), and has focused on addressing areas of the system with highly concentrated reliability performance challenges. As a result of the success of these programs, the demographic risk challenges that the utility faces are now more diffuse in nature, meaning that it would likely take a much greater level of sustainment investment (and maintenance expenditures) to drive material year-over-year improvements in Defective Equipment outages in the next decade. At the same time, as discussed in the Grid Modernization Strategy overview (Section D5), there are evolving systemic challenges such as climate change and electrification which Toronto Hydro expects will have the dual effect of (i) increasing reliability risk on the system due to greater system utilization and more frequent impacts from adverse weather, and (ii) increasing the average customer's sensitivity to outages due to an increased reliance on electricity as their primary source of energy. With these broader trends in mind, the utility concluded that the 2025-2029 investment period would demand a greater emphasis on modernizing the grid, leveraging technologies such as SCADA-operated switches and reclosers, distribution sensors, and advanced distribution management tools to not only continue to improve the customer's overall reliability experience within the rate period, but establish the foundation for full-scale grid automation in 2030 and beyond, ensuring the utility is prepared to deliver stable reliability performance as climate change and electrification pressures accelerate.

Based on these conclusions and related observations from Customer Engagement, the utility set-out to develop an investment plan for 2025-2029 that would (1) include the minimum level of sustainment investment required to maintain the recent average historical frequency of outages caused by Defective Equipment (as represented by the SAIFI Defective Equipment measure), and (2) accelerate ongoing investments in the modernization of the grid in order to improve – in both the short and long-term – the overall customer reliability experience (as represented by the SAIDI measure excluding Major Event Days, Loss of Supply, and Scheduled Outages).[11] Toronto Hydro's

[11] As discussed in Exhibit 1B, Tab 3, Schedule 1, Toronto Hydro has temporarily removed the Scheduled Outages cause code from its custom SAIDI performance measure for the 2025-2029 period due to major forecasting uncertainty for this cause code caused by the recent implementation of OUA, coupled with the underlying expectation that Scheduled Outages will increase in the 2025-2029 period as the result of a larger planned work program.

2025-2029 forecasts and targets for both of these measure can be found in Exhibit 1B, Tab 3, Schedule 1.

E2.3 Customer Priorities, Needs and Preferences in Capital Planning

As described in Exhibit 1B, Tab 5, Schedule 1, Toronto Hydro undertook extensive Customer Engagement as part of business planning for this application. The utility augmented its routine, ongoing customer engagement by engaging Innovative Research Group ("Innovative") to design and implement a planning-specific Customer Engagement study, which was structured in two phases:

- In **Phase 1,** Innovative used a range of techniques to assess customers' needs and preferences. This was an iterative process - initial qualitative (exploratory focus groups) informed the questions that were put to customers in subsequent telephone and online surveys. These surveys (directed at residential, small business, commercial & industrial, and Key Accounts customers) provided quantitative statistically-valid results. The results of this phase directly informed the strategic planning direction for the business plan and informed decision-making throughout the planning process that produced the draft capital expenditure plan.
- In **Phase 2**, Innovative took Toronto Hydro's entire draft plan (including capital & OM&A expenditures) back to customers to solicit customer feedback on seven key investment options, including trade-offs between price and other outcomes. The utility used the results of this phase to refine and finalize its plan.

Further details on the engagement process, the methods used, improvements, and the engagement results can be found in Exhibit 1B, Tab 5, Schedule 1 ("Customer Engagement") and in the final report from Innovative ("the Innovative Report"), Appendix A to that schedule. The following sections provide a detailed overview of how the Customer Engagement results are reflected in the 2025-2029 Capital Expenditure Plan.

E2.3.1 Phase 1 Customer Engagement: Needs and Priorities

The Phase 1 Customer Engagement identified customer needs and priorities in relation to Toronto Hydro's programs and services for the 2025-2029 planning period. Based on low-volume (i.e. residential and GS < 50 kW) customer focus groups conducted at the beginning of Phase 1, in conjunction with an audit of Toronto Hydro's past and ongoing customer engagement efforts, the following set of customer priorities was identified:

1) Delivering electricity at reasonable distribution rates
2) Enabling customers access to new electricity services
3) Ensuring reliable electrical service (including power quality for Key Account customers)
4) Ensuring the safety of electrical infrastructure;
5) Expanding the electrical system so that customers can reduce their impact on climate change by using electricity;
6) Helping customers with conservation and cost savings;
7) Investing in new technology that could help either reduce costs or better help withstand the impacts of adverse weather
8) Minimizing Toronto Hydro's impact on the environment
9) Providing quality customer service and enhanced communications
10) Replacing aging infrastructure that is beyond its useful life.[12]

In addition to identifying and categorizing customers' priorities, Innovative gathered feedback on how customers ranked these priorities. While customer preferences varied somewhat across rate classes, the overall feedback centered around the following common themes:

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.

[12] Exhibit 1B, Tab 5, Schedule 1, Appendix A, page 5

This feedback informed Toronto Hydro's strategic planning direction, including the four investment priorities around which Toronto Hydro's plan is organized: **Sustainment, Modernization, Growth and General Plant**. As discussed in Section E2.1 above, the utility sought to deliver on customer needs and expectations by setting an upper capital expenditures limit that established a balance between keeping rate increases low while ensuring reliability performance and preparing the system for key pressures such as electrification and climate change in a prudent manner. Toronto Hydro concluded that a sustainment level of capital expenditures within its system renewal type investments would provide the minimum funding necessary to:

- maintain reliability over the period consistent with historical average;
- maintain long-term performance by preventing asset failure risk from increasing over the period;
- deliver targeted improvements to customers with below average reliability service; and
- maintain or, in targeted situations, improve upon the utility's performance in other priority areas (e.g. Customer Service, Safety, etc.).

Toronto Hydro also identified the need to invest in the system in 2025-2029 to prepare for increased electrification demands and technological changes expected in the near future. As explained in Section E2.2.1, the utility refined these strategic parameters into specific asset management objectives for the 2025-2029 period (see Table 1) and developed a draft business plan to achieve these objectives. The following subsections describe how each of these objectives aligns with specific Phase 1 Customer Engagement results.

E2.3.1.1 Financial Outcomes/Price

When customers were asked to rank their top three priorities, 46 percent of customers chose price, followed by reliability and investing in new technology at 45 percent each.[13] As compared to residential customers, small business customers appear to be more price sensitive. For small business customers, price is still the clear priority by a strong margin at 54 percent – followed by investing in new technology (40 percent) and reliable service (33 percent).

Commercial and Industrial ("C&I") customers (i.e. GS > 50 kW) expressed preferences similar to residential customers and prioritized reasonable rates and reliable services almost equally – at 50

[13] *Ibid.,* at page 5

percent and 48 percent respectively. This was followed by grid capacity expansion for climate action at 33 percent.

As discussed in detail in E2.1 and E2.2, Toronto Hydro developed a capital plan with necessary trade-offs to strike balance between price and performance/service outcomes that align with customer needs and priorities including: the overarching customer priorities of keeping rates reasonable, maintaining average reliability now and in the long-term, improving resiliency (outage duration), and investing in new technology in the 2025-2029 period. Leveraging the outputs of its asset management tools and processes, Toronto Hydro's plan was calibrated to find the right balance between these key objectives.

E2.3.1.2 Reliability

1. Customer Needs and Priorities

Reliability is becoming an increasingly important priority (on par with price) for residential customers, as compared to five-years ago when the utility conducted a similar customer engagement survey in the course of preparing the 2020-2024 Distribution System Plan and rate application.

When asked specifically about different types of reliability investments all customers, with the exception of Key Accounts, prioritized reducing the length of outages over reducing the number of outages. Residential and small business customers were particularly focused on the reliability impacts of extreme weather events, with a particular emphasis on the need to reduce restoration times in extreme weather events (70 percent and 60 percent respectively).[14]

Overall, Key Account customers prioritized reliable service including power quality (69 percent), followed by reducing outage restoration in extreme weather (52 percent). When asked about reliability investments specifically, the focus was on reducing the number of outages (78 percent) and improving power quality (73 percent). This focus on reducing outages reflects the practical reality that for large business customers any interruptions can be costly due to loss of product, or health and safety issues.

2. Plan Alignment

Toronto Hydro's objectives for its 2025-2029 Capital Expenditure Plan are aligned with and responsive to the customer feedback summarized above. When it comes to reliability performance,

[14] *Ibid.* at page 8.

the utility is balancing price with minimum investments to manage, and where appropriate, reduce asset failure risk through sustainment investments in order to maintain overall SAIDI and SAIFI performance over the plan period as discussed in E2.1 and E2.2 above.

Asset failure risk is assessed by leading indicators like asset condition. Section E2.2 describes the various ways in which the goal of either maintaining, or in some cases reducing, the level of asset risk informed the pacing of Toronto Hydro's investment programs. For example, the utility's pacing of pole replacement for the 2025-2029 period is intended to manage the deterioration of condition demographics of wood poles, which is a key issue for the overhead system. Similarly, Toronto Hydro plans to pace direct-buried cable replacement with the intention of preventing the significant reliability risks related to this asset type from increasing to an extent that would result in deteriorating service and high reactive repair costs over the long-term.

Toronto Hydro's plan also includes investments to improve the resiliency (i.e. the ability to handle emergency events) of the system and utility operations, which aligns with feedback received from residential, small business, and C&I customers. These investments are discussed throughout Section E2.2 and include targeted relocation or undergrounding of critical overhead infrastructure (Section E6.5), the renewal of major stations assets in the downtown core (Section E6.6), modernization of the network system (Sections E6.4 and E7.3), and investment in grid intelligence technologies for contingency enhancements and improved system observability (Section E7.1).

Available capacity is another leading indicator of reliability performance and the ability of the system to handle contingency events. This is especially true given accelerating pressures driven by electrification, which may result in higher asset utilization and subsequent degradation. It is also an important indicator of Toronto Hydro's ability to connect customers and carry-out planned capital and maintenance work efficiently. Toronto Hydro plans to maintain current performance for available capacity through investments in the Stations Expansion,[15] and Load Demand programs.[16]

E2.3.1.3 Investments in New Technology

1. Customer Needs and Priorities

Both Residential and Small business customers prioritize investing in new technology among their top three priorities. When asked specifically about different kinds of investments in new technology,

[15] *Supra* note 15.
[16] Exhibit 2B, Section E5.3.

residential, small business and C&I customers all prioritized investments in new technology that can help Toronto Hydro find efficiencies and reduce customer costs over other types of investments.

In addition, customers across all rate classes support:

- Investing in new technology that would make the system better even if there is an increase to customer rates, as long as Toronto Hydro is clear about the cost to customers and the potential benefits; and,
- Investing in technology that might not provide an immediate benefit but will in the future.

2. Plan Alignment

Toronto Hydro's plan includes paced investment in new technology to improve system performance and reduce costs over time. When it comes to the distribution grid, including system planning and operations, Toronto Hydro's 2025-2029 strategy for deploying new technology (i.e. its modernization strategy) is focused primarily on the steady deployment of industry proven technologies (e.g. reclosers, switches, smart meters, analytics) which the utility has prioritized and paced based on the expectation that they will (1) deliver benefits to customers in the near-term (e.g. improved reliability and operational efficiency), while (2) laying the foundation for more advanced use cases that will deliver greater benefits and essential capabilities in 2030 and beyond (e.g. fully automated "self-healing" grid capabilities; more advanced DER management capabilities to optimize DER value to the grid).

The investments that constitute Toronto Hydro's 2025-2029 Grid Modernization Strategy are largely an extension of the continuous modernization efforts which have delivered benefits for customers over the last decade. For example, a key part of Toronto Hydro's *Grid Readiness* portfolio within its 2025-2029 Grid Modernization Strategy (Section D5) is the Flexibility Services program (discussed in detail in Section E7.2.1). For this program, Toronto Hydro plans to build on the historical success of its Local Demand Response initiative by expanding the use of distributed resources for demand response purposes (i.e. flexibility services). Flexibility Services is a type of programmatic Non-Wires Solution which leverages customer-owned flexible assets to provide the utility with tools for managing capacity constraints. The program also provides customers with new revenue mechanisms and opportunities to engage with their distribution company. While Toronto Hydro expects the expansion of this program to have immediate benefits for customers in the 2025-2029 period (e.g., capacity risk mitigation in areas with local constraints; avoidance and deferral of capital investment), the expansion of this program (and implementation of the *Grid Readiness* portfolio plan more broadly) will also be a crucial and necessary step in accelerating the utility's journey toward leveraging DERs in real-time and at scale – a capability that will be necessary to navigate the energy transition effectively and efficiently for customers in the long-term.

As detailed in Section D5, Toronto Hydro's 2025-2029 Grid Modernization Strategy follows a similar approach for all three major strategic portfolios (*Grid Readiness, Intelligent Grid* and *Asset Analytics & Decision-making*). Toronto Hydro is building on the utility's considerable experience deploying smarter technologies to deliver immediate benefits in 2025-2029, while laying the groundwork for more sophisticated capabilities and benefits that will be essential to maintaining performance and meeting heightened customer and stakeholder expectations for the electricity system beyond 2030.

Toronto Hydro is planning to continue with a similar approach for its corporate service functions and customer-facing service operations in 2025-2029. The utility plans to make paced technology investments to improve data quality, develop new insights and analytics, automate business and customer-facing processes, and deploy digital workforce tools to enhance the efficiency of day-to-day business operations and keep up with evolving customer needs and preferences for services and engagement.

As described in Section D8 ("Information Technology ("IT") Investment Strategy"), Toronto Hydro has a rigorous Enterprise Technology Portfolio ("ETP") framework to ensure consistency in IT investment decisions, establish and maintain governance of investments and achieve alignment with the utility's strategic objectives and target outcomes. Toronto Hydro intends to continue to apply a flexible and agile approach to its IT investments, leveraging the ETP framework and associated technology roadmaps to ensure investments are prioritized with the goal of delivering the appropriate balance of immediate and long-term outcomes for customers. For more details on planned IT/OT investments for the 2025-2029 period, refer to Exhibit 2B, Section E8.4 and Exhibit 4, Tab 2, Schedule 17.

E2.3.1.4 System Capacity Investments

1. Customer Needs and Priorities

Across all rate classes, customers support proactive investment in system capacity to ensure that high growth areas do not experience a decrease in reliability. Key Account and C&I Customers showed particularly strong support for these investments.

When asked to identify their general priorities, 33 percent of C&I customers identified the need to expand the capacity of the grid such that they can reduce their impact on climate change through electrification as one of their top three outcomes.

In fact, the majority (64 percent) 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 with advisory services.

2. Plan Alignment

Toronto Hydro's growth-related investments in the 2025-2029 Capital Expenditure Plan are aligned with customers' expectations to proactively invest in system capacity infrastructure in high growth areas to ensure there is sufficient capacity to maintain current service levels. As discussed in detail in Section D4 – Capacity Planning, Growth and Electrification, when it comes to system capacity, the utility is balancing the need to invest proactively in expanding the system to serve the future needs of its customers with the practical reality that there is uncertainty surrounding the pace of the transition due to policy, technology and consumer behavior factors. Toronto Hydro adopted a "least regrets" planning approach to anticipate and minimize regretful outcomes in the light of this uncertainty.

To facilitate this approach, the utility enhanced its System Peak Demand Forecast with additional inputs for electric vehicles ("EVs"), data centers and Municipal Energy Plans, assessment of spare feeder positions, identification of system constraints that impact generation connections, and identification of unique drivers for demand growth. Toronto Hydro also augmented its decision-making process with the results of a long-term scenario modelling tool known as Future Energy Scenarios, which projects what demand would be under various policy, technology and consumer behaviour assumptions that are linked to Net Zero 2040 or 2050 objectives. The Future Energy Scenarios is described in more detail in Exhibit 2B, Section D4, Appendix A.

The resulting growth-related investments are described in Section 2.4.1 and include the connection of load and generation customers,[17] the accommodation of third-party relocations,[18] capacity

[17] Exhibit 2B, Section E5.1.
[18] Exhibit 2B, Section E5.2.

expansion,[19] and non-wires solutions.[20] Note that Toronto Hydro's "least regrets" investment approach is further reinforced by the utility's Grid Modernization strategy outlined in Exhibit 2B, Section D5. The Grid Modernization Strategy recognizes the need to prepare for coming transformations by transitioning towards a more technologically advanced distribution system, and developing advanced capabilities that over time will provide greater flexibility to:

- take a "wait and see" approach to capital investment needs that have a higher degree of uncertainty, and
- implement increasingly cost-effective technology-based solutions to address grid needs and deliver reliability, resilience, system security and other valuable customer outcomes as electrification accelerates in the next decade and beyond.

As part of this strategy, Toronto Hydro is investing in developing a more intelligent grid (e.g. contingency enhancements, and investments in sensors and next generation smart meters that are expected to improve grid observability, and the implementation of grid automation solutions such as FLISR). These modernization investments, once implemented on the grid and integrated into utility operations, provide enhanced capabilities to observe system performance at an asset-level and make real-time (and increasingly automated) operating decisions. Building these capabilities is necessary to improve accuracy and granularity of load forecasting and optimize the capacity and performance of a more heavily utilized grid, including at the neighbourhood level, where consumer technologies such as electric vehicles are expected to increasingly drive the need for low-voltage system expansions on a more rapid timescale.

E2.3.2 Phase 2 Customer Engagement

Toronto Hydro's consultant Innovative presented the draft plan to customers in the Phase 2 customer engagement to solicit feedback on the following:

- pacing and bill impacts for key investments areas in Toronto Hydro's plan;
- the price of the overall draft plan and whether customers are willing to accept it.

In an effort to be more transparent about the plan, its investments priorities, and outcomes including the price impacts, Toronto Hydro put its entire draft plan to customers. To help customers

[19] *Supra* note 15.
[20] Exhibit 2B, Section E7.2.

understand the investment priorities and provide feedback in terms of trade-offs between price and pacing towards outcomes, Toronto Hydro broke down the draft plan into seven key choices:

1. **Modernization**: Investments to build a smarter, more efficient and resilient grid for the future.[21]
2. **Growth**: Investment to increase the grid's capacity to reliably serve customers growing electricity needs.
3. **Sustainment**: Investments to manage reliability risk due to equipment failure.
4. **Sustainment:** Investments in the paced upkeep of equipment at or near end of life.
5. **Sustainment**: Investments to standardize outdated equipment.
6. **General Plant**: Investments in fleet, facilities and IT infrastructure to keep the business running efficiently.
7. **Decarbonization**: Investments to reduce greenhouse gas emissions from Toronto Hydro's operations by electrifying fleet and facilities assets.

E2.3.2.1 Phase 2 Results

For each of these options, Toronto Hydro put forward the draft plan, along with the options to spend more or less for faster or slower progress towards key outcomes such as reliability, system health, customer service, efficiency, and environment. The outcomes for each investment option were set out in a table, and the interactive slider allowed customers to dial the draft plan up or down based on their preferences. These options to spend more or less were grounded in the investment options developed and considered throughout the planning process.

After considering and providing feedback on the pacing and prioritization in the seven key areas noted above, customers were asked whether Toronto Hydro should stick with its proposed plan, accelerate spending to improve system outcomes, or scale back the plan. An average of 84 percent of customers, across all rate classes either supported sticking with the plan or spending more to improve system outcomes.

While a majority of customers supported the plan, or one that does even more to improve system outcomes, when asked to make certain trade-offs between price and pacing, customers expressed certain preferences to increase, maintain or reduce the pace of the investment plan. Through this

[21] For the purpose of Phase 2 Customer Engagement, Toronto Hydro mapped a portion of IT software enhancements including the Advanced Distribution Management System (ADMS) project, and cyber security investments to the Modernization category in order to provide customers a more comprehensive view of the price impact of this priority.

feedback on the investment categories, Toronto Hydro was also able to understand where customers prioritize spending.

Generally, customer preferences in terms of trade-offs between price and progress were in-line with Toronto Hydro draft plan in Modernization, Stewardship and Standardization, and slightly lower than the draft plan on Growth, Reliability and General Plant (including Running the Business and Decarbonization). Toronto Hydro used this feedback, along with other information obtained in the normal course of the planning process, to refine and finalize the Plan.

E2.3.2.2 Final Plan Adjustments

Toronto Hydro concluded from the Phase 2 Customer Engagement process that the draft plan achieved an appropriate balance between keeping prices reasonable and delivering the outcomes that customers need and prioritize. In addition, Toronto Hydro used the Phase 2 results to inform the finalization of the plan, making some adjustments where appropriate to reflect customer preferences. Overall, these customer-feedback driven adjustments yielded a further top-down constraint on the plan of approximately $70 million, as summarized in section E2.1.3 above.

E2.4 Portfolio Planning for 2025-2029

Toronto Hydro's Portfolio Planning process used the outputs of the Asset Needs Assessment to develop program-level expenditure plan proposals that would support the utility's asset management outcome objectives for 2025-2029.

As described in Section D3.4.3, Toronto Hydro developed bottom-up expenditure plan scenarios for each capital program, leveraging the asset lifecycle optimization and risk management practices and methodologies described in Section D3. The proposals were evaluated in relation to their potential contribution to: (i) the utility's outcome objectives and measures; and (ii) alignment with customer needs and preferences. The program proposals were further refined as a result of business inputs and information, as well as feedback received in the second phase of Customer Engagement (discussed in Section E2.3 above).

The following subsections describe how the outputs of the Asset Needs Assessment and the utility's asset lifecycle optimization and risk management practices informed the timing and pacing of the programs in the 2025-2029 Capital Expenditure Plan under the focus areas of Growth, Sustainment, Modernization, and General Plant.

E2.4.1 Growth Expenditures

Toronto Hydro developed a 2025-2029 Growth expenditure plan that is responsive to the utility's need to continuously meet its legally mandated service obligations, including the requirement to safely connect load and generation customers in a timely manner, and requirements to comply with revenue metering and billing standards. The pacing of investments in this category was largely dictated by the anticipated projected demand in these areas over the 2025-2029 period. Toronto Hydro considered the expected impacts of increased electrification demands on the grid in the 2025-2029 period and relied on the Peak Demand Forecast to understand growth drivers and the related investment needs.

Table 3: 2025-2029 Growth Expenditure Plan ($ Millions)

Capital Program	Costs ($M)
Customer Connections (Exhibit 2B, Section E5.1)	$477
Externally Initiated Plant Relocations & Expansions (Exhibit 2B, Section E5.2)	$76
Load Demand (Exhibit 2B, Section E5.3)	$236
Generation Protection, Monitoring, and Control (Exhibit 2B, Section E5.5)	$35
Non-Wires Alternatives (Exhibit 2B, Section E7.2)	$23
Stations Expansion (Exhibit 2B, Section E7.4)	$173
Growth Capital	**$965**

E2.4.1.1 Connecting Load Customers

Toronto Hydro's Customer Connections,[22] and Load Demand programs support the safe, timely, and cost-efficient connection of load customers.[23] Forecast expenditures for load connections are based on historical trends in gross cost and customer contribution amounts for load connection activities. They are also informed by development trends in the City[24] and the adoption of emerging technologies catered towards clean energy and electrification. The utility's 2025-2029 expenditure plan anticipates growth in new services, upgrades, and removals based on current and proposed development. (Refer to Section E5.1 for more details.)

[22] *Supra* note 17.
[23] *Supra* note 16.
[24] As described in Exhibit 2B, Section B2.2, Toronto Hydro's Development Planning team leverages the City of Toronto's development pipeline to engage large customers and developers with upcoming projects.

The Load Demand program addresses near-term system capacity constraints in areas of concentrated load growth. Toronto Hydro's Distribution Capacity and Capability Assessments (summarized in Section D3.3) identified a number of areas in both the Horseshoe and Downtown regions of the system where investments such as load transfers, cable upgrades, and equipment upgrades will likely be required to ensure the utility can continue to connect customers efficiently. These investments are also necessary to maintain sufficient grid flexibility to handle contingency scenarios and optimize planned work schedules, contributing to Toronto Hydro's reliability objectives and improving customer satisfaction by providing large customers with greater scheduling flexibility for planned outages.

Overall, the proposed expenditure plans in these two load-driven Growth programs reflect the investments required to connect customers in accordance with the OEB's service connection targets, while maintaining system performance for existing customers and improving the effects of scheduled outages on the operations of larger customers.

E2.4.1.2 Connecting Generation Customers

Toronto Hydro's Customer Connections,[25] and Generation Protection, Monitoring, and Control programs ("GPMC"),[26] support the safe, timely, and cost-efficient distributed energy resource ("DER") connections to the distribution system, including renewable energy generation ("REG") projects. The utility aligned the planned 2025-2029 expenditures in both programs with its 2023-2029 DER connection and capacity forecasts, illustrated in Figures 2 through 8 in Section E3. These forecasts considered historical connection trends, current pipeline of applications, the economic environment, government and regulatory incentives, and net zero initiatives. The utility currently projects that the total number of DER connections will grow from about 2,700 in 2023 to nearly 4,500 by the end of 2029 – an increase of roughly 67 percent.

Toronto Hydro's Generation Capacity and Capability Assessment (described in Section E3.3) identified a number of challenges to accommodating the forecasted 516.7 MW of DERs on the system by the end of 2029, including short-circuit capacity constraints, islanding risks, and system thermal limits. To address the above challenges and continue to connect all forecasted DERs, Toronto Hydro plans investments in Generation Protection, Monitoring, and Control,[27] and Energy Storage

[25] *Supra* note 17.
[26] Exhibit 2B, Section E5.5.
[27] *Ibid*.

Systems (Non-Wires Solutions Program).[28] Through the GPMC program, the utility aims to install six bus-tie reactors to address short-circuit capacity constraints and 315 monitoring and control systems to monitor system conditions in real time and to ensure all DER sites are de-energized in the event of a system fault. Through the Energy Storage Systems ("ESS"), Toronto Hydro intends to develop a scalable, demand-driven, ESS strategy that enables renewable integration. ESS can act as a load to prevent output curtailment from the renewable assets while ensuring a stable grid through controlling the minimum load to generation ratio. Toronto Hydro plans to deploy nine renewable-enabling ESS projects

E2.4.1.3 Accommodating Third-Party Plant Relocation Requests

The Externally Initiated Plan Relocations and Expansions program funds plant relocations and expansions triggered by third-party requests.[29] In accordance with OEB's Distribution System Code ("DSC") and related legislation (i.e. *Building Transit Faster Act, 2020* and *Public Works and Highways Act, 1998)*, Toronto Hydro is legally obligated to work cooperatively with third parties towards accommodating these requests in a fair and reasonable manner.[30][31] For the 2025-2029 period, the utility developed an expenditure plan to address committed relocation and expansion projects from third-parties, including Road Authorities (e.g. the City of Toronto), Metrolinx, and the TTC. Toronto Hydro gathers information on capital projects through direct consultation with external agencies, participation in the Toronto Public Utilities Coordination Committee, and reviewing governmental and public agency publications.[32] These capital plans and project schedules are subject to change at the discretion of the sponsor agencies, and any such changes typically impact the timing and potential the scope of Toronto Hydro's relocation and expansion work.

E2.4.1.4 Capacity Expansion and Demand Response

Whereas Toronto Hydro's Load Demand investments are driven by the short-term capacity needs of the system, its Stations Expansions investments are driven by long-term capacity needs of the system to renew and expand its stations. The utility's investment plans are informed by its Station Load Forecast (for more details see Section D4), the Regional Planning process, and are aligned with Hydro

[28] *Supra* note 20.
[29] *Supra* note 18.
[30] The Distribution System Code, (August 2, 2023), Section 3.1.10.
[31] *Building Transit Faster Act ("BTFA"), 2020*, S.O. 2020, c. 12 and *Public Works and Highways Act, 1998*, RSO 1990, Ch P.49.
[32] Exhibit 2B, Section B - Coordinated Planning

One's sustainment plans. Given the complexity and size of these individual projects, their expenditures are discrete and not conducive to smoothing over the rate period.

Investments for the 2025-2029 period are driven by anticipated bus-level constraints for stations serving areas of high growth and development, and are fully aligned with the results of regional planning activities conducted in coordination with the Independent Electricity System Operator ("IESO") and Hydro One.[33] The most recent planning document from this process is the Needs Assessment Report for the Toronto Region. Refer to Section B for more information on coordinated system planning with third parties. The proposed projects will add or free up 574 MVA capacity, supporting the sustainment of reliability, operational flexibility, and connections capabilities.

E2.4.2 Sustainment Expenditures

Continued proactive renewal expenditures are required during the 2025-2029 period to manage significant safety, reliability and environmental asset risks and to ensure stable and predictable performance for current and future customers.[34] As described in Section E2.2.1.1. above, approximately one quarter of Toronto Hydro's assets are operating beyond useful life. The system continues to age at a rate comparable to the projected rate of aging in recent rate periods, although a slight increase is expected in the assets at end-of-life by 2030. Condition demographic results continue to indicate substantial asset investment needs for a number of asset classes, and the utility continues to face challenges related to higher-risk, obsolete legacy assets and asset configurations such as rear lot plant and direct-buried cable.

The first phase of Customer Engagement revealed that most low-volume and medium-sized customers were satisfied with average reliability performance while larger users indicated a greater interest in reliability and reduction in restoration times. In light of these results, and leveraging the asset risk assessment and mitigation practices discussed in Section D3, Toronto Hydro developed program expenditure plans for 2025-2029 that ensure the minimum pace necessary to sustain overall asset risk and reliability performance at current levels, while also driving targeted outcome improvements. These outcome improvements include, reducing the risk of PCB contaminated oil spills, reducing the level of failure risk related to a significant backlog of aging and poor condition stations assets, and improving performance on worst performing feeders.

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[33] It is also important to note that these investments are aligned with Hydro One's sustainment plans.
[34] See detailed description in Overview of Distribution Assets (Section D2) and in the System Renewal programs (Section E6).

Table 4: 2025-2029 Sustainment Expenditure Plan ($ Millions)

Capital Program/Segment	Costs
Area Conversions (Exhibit 2B, Section E6.1)	$237
Underground Renewal – Horseshoe (Exhibit 2B, Section E6.2)	$476
Underground Renewal – Downtown (Exhibit 2B, Section E6.3)	$165
Network System Renewal (Exhibit 2B, Section E6.4)	$123
Overhead Renewal (Exhibit 2B, Section E6.5)	$273
Stations Renewal (Exhibit 2B, Section E6.6)	$218
Reactive and Corrective Capital (Exhibit 2B, Section E6.7)	$328
Sustainment Capital	**$1,820**

E2.4.2.1 Overhead Asset Renewal Investments

Toronto Hydro's Overhead System Renewal,[35] Area Conversions,[36] and Reactive and Corrective Capital programs address failure and obsolescence risks related to overhead grid system assets.[37] The utility paced the 2025-2029 expenditure plan for these programs to: (i) maintain current system reliability performance; (ii) prevent age and condition related asset risk from accumulating over the period; and (iii) continue to reduce and eliminate safety and environmental risks and other deficiencies associated with legacy assets and asset configurations.

Demographic pressure on wood poles and pole top transformers is the key driver of overhead renewal need during the 2025-2029 period is.[38] Wood poles are critical to the safety and viability of the distribution system.[39] About 9,000 poles, or ten percent of Toronto Hydro's wood pole population, currently show at least material deterioration (i.e. HI4). The utility projects the total number of poles at material deterioration or worse condition could more than triple to an estimated 32,000 by 2030 without intervention (including an increase in poles at "end-of-serviceable life" from approximately 500 to over 7,000). Toronto Hydro's 2025-2029 expenditure plan will manage failure risk by prioritizing replacement of poles near or at "end-of-serviceable life" condition (i.e. HI5). The

[35] Exhibit 2B, Section E6.5.
[36] Exhibit 2B, Section E6.1.
[37] Exhibit 2B, Section E6.7.
[38] See section D2.1.1.
[39] Wood pole replacement is the highest-volume renewal activity out of the subset of assets that are analyzed through Toronto Hydro's ACA methodology. Given the importance of managing the overall condition-informed failure risk for this asset class over the planning period, the utility began tracking the wood pole condition demographics as a Custom Performance Measure starting in 2020 (see Section C for more details).

Overhead System Renewal program budgets for approximately 12,000 pole replacements from 2023 to 2029. In addition, the Area Conversions,[40] and the Reactive Capital programs will also include pole replacements.[41]

The percentage of pole-top transformer units operating beyond their 45-year useful life is projected to increase from 24 percent to 30 percent by the end of 2029. Compounding the reliability dimension of this risk is potential for oils spills, including spills containing PCBs, from pole-top transformer failure. The utility has paced pole-top transformer replacement to align with reliability objectives and to work towards eliminating the risk of PCB contaminated oil spills by 2025.

Figure 7: Rusted Overhead Transformers at Risk of Leaking Oil

The Area Conversions program addresses the obsolete, legacy overhead construction types which are an ongoing challenge for Toronto Hydro, including rear lot construction and box construction. Because of the continuing decline in rear lot plant performance, and the high complexity and duration of rear lot conversion projects, Toronto Hydro determined it is necessary to continue removing rear lot plant proactively at a steady pace, prioritizing areas where customers are experiencing the worst performance. For box construction, Toronto Hydro developed a plan for 2025-2029 that continues the strategy of eliminating all box construction poles by 2026, as first articulated in the 2015-2019 DSP. This is the fastest executable rate at which the utility can eliminate this legacy configuration.

[40] *Supra* note 36.
[40] *Ibid*.
[41] *Supra* note 37.

Figure 8: Box Construction (left). Replacing a transformer on a poor condition Rear Lot pole (right)

E2.4.2.2 Underground Asset Renewal Investments

Failure and obsolescence risks related to underground system assets are addressed by Toronto Hydro's Underground System Renewal – Horseshoe,[42] Underground System Renewal – Downtown,[43] Area Conversions,[44] and Reactive and Corrective Capital programs.[45] As with the overhead asset renewal investments, the 2025-2029 expenditure plan for these programs is paced to maintain system reliability, prevent age and condition related risk from accumulating and reduce and eliminate safety and environmental risks.

Legacy asset performance and risks – particularly the reliability-related failure risks associated with obsolete cables (i.e. direct buried and lead) – continue to be the most significant driver of renewal needs on the underground system. Underground cables have been the single greatest contributor to outages caused by defective equipment, resulting on average in 146,000 customer hours of interruption annually.

The utility's Asset Needs Assessment identified 666 circuit-kilometres of direct-buried cable and direct-buried cable in duct remaining in the Horseshoe area as of 2022. Of this, approximately 370 circuit-kilometres are of the highest-risk cross-linked polyethylene ("XLPE") type. Approximately 61 percent of this cable is currently beyond its useful life and the utility anticipates that 64 percent will be at or beyond useful life by end of 2029. To prevent reliability from degrading, the utility developed

[42] Exhibit 2B, Section E6.2.
[43] Exhibit 2B, Section E6.3.
[44] *Supra* note 36.
[45] *Supra* note 37.

a plan to proactively replace an estimated 182 circuit-kilometres of this cable in the Underground System Renewal – Horseshoe program during the 2025-2029 period, prioritizing the highest-risk neighbourhoods based on cable age, performance, criticality, and adjacency to other assets at risk of failure.[46]

Toronto Hydro's Asset Needs Assessment also resulted in the continuation of a long-term renewal strategy for lead cable in the downtown area. Due to the generally good reliability performance of lead-covered cable, Toronto Hydro has historically managed these assets through reactive and corrective interventions and targeted repairs. However, these cable types have shown signs of aging and declining performance in recent years and are largely considered obsolete in North America due to various safety and environmental risks (see Section E6.3 for more details).[47]

Figure 9: Collapsed cable splice

To manage the significant magnitude of this asset renewal need, Toronto Hydro developed a prioritization model to rank primary feeder cable segments in the system using factors such as historical failures, cable types, number of splices, age and customer base.[48] Based on this prioritization model, Toronto Hydro developed a plan to maintain reliability performance for affected customers by replacing approximately 3.5 percent of the 985 kilometres of paper-insulated lead-covered ("PILC") and 5.2 percent of the 176 kilometres of asbestos-insulated lead-covered PILC cable with modern polymeric cables in the 2025-2029 period.

[46] Given its significant impact on reliability and the fact that this is the utility's largest renewal activity, Toronto Hydro plans to continue reporting its progress on this plan as a 2025-2029 Custom Performance Measure under the Reliability outcome category (see Section C).
[47] There is only one supplier of paper-insulated lead-covered ("PILC") cable remaining in North America and no suppliers of asbestos-insulated lead-covered ("AILC") cable.
[48] The results of this analysis are summarized in Exhibit 2B, Section E6.3, Figures 1 and 2.

Other electrical assets addressed by the Underground System Renewal programs include transformers and switches in the Horseshoe area and on the Underground Residential Distribution ("URD") system, which serves low-volume customers in parts of the downtown area. These assets will be prioritized based on age, condition and historical performance and will largely be addressed in conjunction with underground cable rebuild projects and voltage conversion, except on the URD system and in cases where submersible, pad-mount and vault transformers must be replaced on a spot basis by 2025 to reduce risks of PCB contaminated oil spills.

Figure 10: Corrosion on top of a Submersible Transformer

The Underground System Renewal – Downtown program also continues a proactive cable chamber renewal plan. Managing the condition-related risk of failure of cable chambers is essential to ensuring the safety and long-term viability of the underground system. Toronto Hydro has historically managed these civil assets reactively, however, the latest Asset Needs Assessment identified a significant population of cable chambers with at least material deterioration. There are currently 130 cable chambers currently in "end-of-serviceable life" condition (HI5) and 462 in material deterioration condition (HI4). Toronto Hydro developed a plan to proactively help prevent condition demographics from deteriorating further over the 2025-2029 period by rebuilding approximately 45 cable chambers, replacing approximately 2,800 cable chamber lids, rebuilding over 120 cable chamber roofs and addressing an estimated 25 cable chambers that need to be abandoned.

Figure 11: Cable Chamber roof in HI5 condition (left), Cable chamber roof inside view (right)

Starting in 2025, Toronto Hydro is introducing a planned renewal segment to address underground switchgear in customer-owned vaults that feed apartment buildings, educational facilities and community centres. Previously Toronto Hydro managed the replacement of these assets on a reactive basis, however, these require replacement due to obsolescence. Toronto Hydro plans to target the worst condition and most critical assets to maintain average reliability performance for customers served by these assets.

E2.4.2.3 Network Asset Renewal Investments

Failure and obsolescence risks related to network system assets are addressed by Toronto Hydro's Network System Renewal,[49] and Reactive and Corrective Capital programs.[50] The utility paced the 2025-2029 expenditure plans for these programs to: i) maintain current system reliability performance; ii) improve resiliency and operational efficiency of the network; iii) prevent age, condition and obsolescence related asset risk from accumulating over the period; and iv) continue to reduce and eliminate safety and environmental risks (and other deficiencies) associated with legacy assets and asset configurations.

The network system plays an important strategic role in meeting the reliability expectations of interruption-sensitive customers in the City's core, which contains dense, high-traffic commercial and residential areas. The network system is designed to handle normal failure scenarios better than Toronto Hydro's other system configurations.[51] However, in the case of catastrophic failures such as a vault fire, the entire secondary network grid that is connected to the vault must be de-energized until the situation can be safely remedied, which can take over 24 hours. These types of failures can

[49] Exhibit 2B, Section E6.4.
[50] *Supra* note 37.
[51] Exhibit 2B, Section D2.2.3.

result in risks to public safety and the environment. To minimize these scenarios, Toronto Hydro takes a highly proactive approach to network equipment and vault maintenance and renewal.

Figure 12: Damage from a network vault fire

The risk of flooding continues to be a concern on the network system. As noted in Section D2.1.2, four of the 10 highest rainfall years on record have occurred in the last decade. Toronto Hydro developed a plan for the 2025-2029 period that targets non-submersible network units which are susceptible to water ingress and have elevated failure risks even when in good condition. There are currently 43 network transformers with material deterioration. Condition projections suggest that 149 units will be in HI4 and HI5 condition by 2029 without intervention. Age projections indicate that 50 percent of the system's network units will be at or beyond useful life by 2034. Toronto Hydro is planning to replace 95 units in 2023-2024 and 130 units in 2025-2029. This pace of replacement is expected to reduce failure risk on the network system by improving condition-related asset risk across the network unit population.

To mitigate risks to public and employee safety, the utility also plans to continue proactively renewing network vaults in poor condition. The number of vaults in HI4 and HI5 condition is expected to grow from 91 to over 130 by 2030 without intervention, which would represent 29 percent of the population. The utility is planning to proactively address 38 vaults over the 2025-2029 period. Network vault rebuilds are complex projects in congested areas and require significant planning efforts, making it necessary for the utility to maintain a steady and proactive renewal program over time.

Toronto Hydro plans to reconfigure three networks over the 2025-2029 period as part of its Network Circuit Reconfiguration segment (under Network System Renewal program).[52] This segment involves

[52] *Supra* note 49.

reconfiguring and re-cabling secondary grid networks into more robust spot vaults and enhanced grids. These reconfigurations will help improve outage restoration time and reduce risks associated with second contingency events for downtown network customers.

E2.4.2.4 Stations Renewal Investments

Toronto Hydro's Stations Renewal,[53] and Reactive and Corrective Capital programs address failure and obsolescence risks related to stations assets.[54] Stations assets are highly critical assets that have the potential for causing widespread and lengthy interruptions in the event of failure.[55] Stations asset replacement projects are complex and typically require long lead and execution timelines. In light of these operational constraints and a growing backlog of stations renewal needs, Toronto Hydro developed a plan for the 2025-2029 period that addresses stations equipment at a faster pace than in the 2020-2024 period. This is needed to maintain station asset demographics, as well as to replace obsolete station electromechanical relays with modern digital relays – an important part of Toronto Hydro's Intelligent Grid strategy as discussed in the Grid Modernization Strategy in Section D5.

The Asset Needs Assessment for stations assets continues to identify a significant backlog of aging equipment, with 42 percent of switchgear, 51 percent of power transformers, 48 percent of outdoor breakers, and 55 percent of DC battery systems operating at or beyond their useful life. The need for investment was further underscored by the high proportion of assets in moderate (H3), material (HI4), and end-of-serviceable-life (HI5) condition, as shown in Figure 13 below.

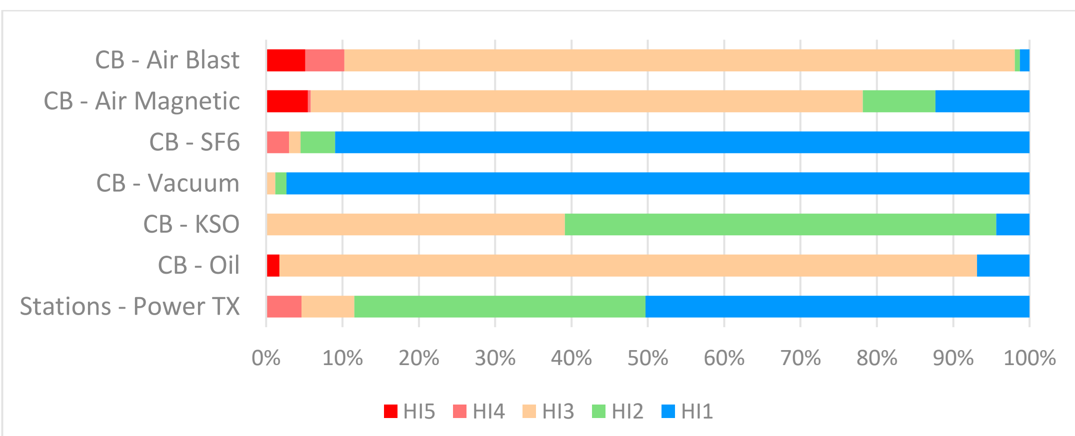

Figure 13: Asset Condition Assessment of Station Assets

[53] Exhibit 2B, Section E6.6.
[54] *Supra* note 37.
[55] *Supra* note 53.

Overall, in support of its objectives to maintain reliability, improve system resiliency, and manage the long-term viability of the distribution system, Toronto Hydro developed plans to execute the following stations work in the 2025-2029 period:

- Replace three TS switchgear units –serving the highest-density areas of Toronto – all of which are beyond their 50-year useful life and feature obsolete circuit breaker designs contained within non-arc resistant enclosures (elevating safety risks for employees);
- Replace 12 TS outdoor circuit breakers prioritized based on condition, age, load served, and at risk of containing PCB;
- Replace 63 TS outdoor switches that are beyond their 50-year useful life, reducing the risk of lengthy interruptions for customers in the North York area of Toronto;
- Remove 12 aging and deteriorating Municipal Station ("MS") switchgear with obsolete circuit breakers;
- Replace 15 power transformers, to mitigate an increased failure rate in this rate period and the next. All power transformers will be between 54 and 66 years of age at the time of replacement and have identified condition concerns such as high-power factor and low insulation resistance;
- Replace 1 end-of-life MS primary supply, which has assets older than 60 years of age at the time of replacement; and
- Renew end-of-life stations battery and ancillary systems.

E2.4.2.5 PCB Risk Reduction Strategy

Toronto Hydro's risk mitigation strategy for PCB contaminated oil spills is a key driver and prioritization consideration for multiple renewal programs. Due to the toxic and persistent nature of PCB, the Government of Canada's PCB Regulations[56] prohibit the use of equipment that contains greater than 50 ppm PCBs, or the release of greater than one gram of PCBs, which could result from an oil leak with significantly less than 50 ppm. The City of Toronto also enforces its own PCB-related bylaws with a near-zero tolerance for the discharge of PCBs into the storm and sanitary sewer systems.

Toronto Hydro is continuing its efforts to eliminate the risk of oil spills containing PCBs on its overhead, underground, and network systems by 2025 through inspection and testing under its

[56] PCB Regulations (SOR/2008-273), under the *Canadian Environmental Protection Act, 1999.*

maintenance programs (discussed in Exhibit 4, Tab 2, Schedules 1-4) and through targeted asset replacement as set out in the programs described above.[57]

E2.4.3 Modernization Program Expenditures

Toronto Hydro developed a 2025-2029 Modernization expenditure plan that targets a select number of system enhancement needs that support the utility's asset management objectives for the period and deliver customer value using technology-driven solutions. Toronto Hydro's modernization investments are aligned with its 2025-2029 Grid Modernization Strategy, discussed in Section D5. This strategy is driven by a confluence of external drivers – including accelerating climate change; emerging decarbonization and energy innovation policy mandates; rapid digitalization of the economy; and potential decentralization of the energy system (i.e. Distributed Energy Resources) – which threatens to overwhelm grid capacities and capabilities in the long-term if not proactively addressed. The Grid Modernization Strategy addresses these emerging challenges and parallel opportunities in a paced manner that leans first and foremost into the deployment of proven technologies (e.g. reclosers, switches, smart meters, analytics), which will deliver benefits to customers in the near-term (e.g. improved reliability), while laying the foundation for more advanced use cases that will be required in 2030 and beyond. Complementing this focus on proven technology is a secondary emphasis on innovation. There are certain challenges – e.g. cost-effectively increasing the amount of distributed generation that can connect to congested feeders – for which the optimal technological and commercial solutions are not yet settled or mature. In these areas, Toronto Hydro is planning to increase its investment in pilot projects and industry partnerships, which the utility believes can contribute to accelerated progress across the entire sector. For a comprehensive overview of the core elements of the Grid Modernization Strategy, refer to Section D5.

Table 5: 2025-2029 Modernization Expenditure Plan ($ Millions)

Capital Program/Segment	Costs ($M)
System Enhancement (Exhibit 2B, Section E7.1)	$151
Network Condition Monitoring and Control (Exhibit 2B, Section E7.3)	$6
Metering (Exhibit 2B, Section E5.4)	$248
Overhead Resiliency (Exhibit 2B, Section E6.5)	$86

[57] Overhead System Renewal (*Supra* note 35.), Underground System Renewal (*Supra* note 42 and 43), Stations Renewal (*Supra* note 52), and Reactive and Corrective Capital (Exhibit 2B, Section E6.7). Refer to each of these programs for a description of how the planned investments address PCB at-risk equipment and potential challenges.

Capital Program/Segment	Costs ($M)
Stations Control and Monitoring (Exhibit 2B, Section E6.6)	$65
IT Cyber Security & Software Enhancements (Exhibit 2B, Section E8.4)[58]	$94
Modernization Capital	**$651**

E2.4.3.1 Metering Investments

Investments in the Metering program (Section E5.4) are triggered by the need to remain in compliance with OEB's minimum standards for billing accuracy and Measurement Canada and IESO requirements related to metering and billing. Based on a needs assessment for its metering assets, Toronto Hydro developed a plan for 2025-2029 that is largely driven by the timing of metering and metering system upgrade cycles. Residential and Small Business (C&I) Meter Replacement activities will continue in order to address end-of-life meters with expiring seals. Toronto Hydro cannot, as a matter of law, bill customers using meters with expired seals. Through these replacements, Toronto Hydro plans to install next generation smart meters (referred to as Advanced Metering Infrastructure 2.0 or AMI 2.0) and upgrade the supporting metering infrastructure. AMI 2.0 will play an important role in establishing a greater level of system observability within Toronto Hydro's Grid Modernization Strategy. For more information on expected use cases for AMI 2.0, please refer to Section D5.2.2 and D5.3.1.

E2.4.3.2 System Design Enhancements and Modernization

Through the Asset Needs Assessment and the Portfolio Planning process, as well as the parallel Grid Modernization Strategy development exercise, Toronto Hydro identified several targeted opportunities to address asset risk and enhance customer value by improving system design and investing in system modernization. The bulk of this planned investment is in the System Enhancements (Section E7.1) and Network Condition Monitoring and Control (Section E7.3) programs. These programs will continue Toronto Hydro's efforts to identify places on the system where asset failure risk can be mitigated, outage restoration capabilities improved, and future operational costs reduced through the installation of protection devices and remote SCADA-enabled switches and sensors.

[58] For the purpose of Phase 2 Customer Engagement, Toronto Hydro mapped a portion of IT software enhancements including the Advanced Distribution Management System (ADMS) project, and cyber security investments to the Modernization category in order to provide customers a more comprehensive view of the price impact of this priority.

The Network Condition Monitoring and Control program was introduced for 2020-2024 and arose out of the need to address performance risks and connection capability challenges on the network system. These issues risk eroding the long-term viability of the network at a time when its compact and reliable design is becoming an increasingly effective option for medium and large customers in developing, high-density areas of the City. Toronto Hydro expects to continue its original objectives of the program to install monitoring and control equipment and fibre optic cable in approximately 920 network vaults by the end of 2026. This will complete Toronto Hydro's first major implementation of an entirely new set of distributed smart grid capabilities since the initial roll-out of AMI. Organizational learnings from this program, including the successful achievement of reliability, and cost reduction and avoidance benefits, will be applied to the implementation of Toronto Hydro's 2025-2029 Grid Modernisation Strategy. Pilot projects to further enhance network monitoring capabilities, such as the installation of fire sensors, analog water sensor, a vault camera, vault hatch open sensor, and secondary cable monitoring with cable sensors will commence after 2025. These improvements will enhance Toronto Hydro's ability to detect emergencies earlier and prevent catastrophic accidents from occurring.

Over the 2025-2029 period, the System Enhancements program is comprised of three investment initiatives that will strategically address critical issues like operational constraints, security-of-supply risks and system operational inefficiencies. The Contingency Enhancement segment will continue to enhance Toronto Hydro's ability to efficiently restore power to customers in the Horseshoe and Downtown areas. By installing 205 new SCADA switches in the Horseshoe, this segment will ensure that at least 90 percent of Horseshoe feeders have the minimum infrastructure (SCADA switches and reclosers) in place to integrate into a "self-healing" network beginning in 2030. It will deploy a total of 298 switches and 220 reclosers more broadly on parts of the system that can benefit materially from improved outage restoration and protections, contributing to Toronto Hydro's objective of improving SAIDI generally, as well as improving reliability for customers on poor performing feeders over the 2025-2029 period, and ensuring the system has appropriate flexibility to maintain reliability and operate efficiently over the long-term in the face of demand growth and potential DER proliferation. The Downtown Contingency segment allows for N-2 (i.e. two station loss-of-supply issues at the same time) operational capability to address serious, high-impact loss-of-supply scenarios for areas of the city with critical institutional and economically significant loads. Copeland Station is the optimal downtown anchor source, and for the 2025-29 period, eligible stations with 3000A feeder positions will receive station-to-station switchgear ties. Lastly, in accordance with Toronto Hydro's grid modernization goals, the System Observability segment will introduce new equipment that improves reliability and system awareness of the distribution system, contributing to improved operational efficiency, outage response, asset management decision-making, and load and generation forecasting. This will be achieved through the targeted deployment of sensors (such as overhead and underground sensors, online cable monitoring, and transformer monitoring) that will provide the utility's planners and grid operators with real- or near-real time insight into asset performance and operating conditions at critical points on the grid.

In addition to the System Enhancements and the NCMC programs, Toronto Hydro plans to renew and modernize protection, control, monitoring, and communication assets at its Transformer and Municipal Stations. Replacing these deteriorated and obsolete assets enables the utility to sustain reliability, and advance the modernization of Toronto Hydro's substations. During the 2025-2029 period, Toronto Hydro plans to renew 33 existing Remote Terminal Units (RTUs) and replace 251 obsolete relays with modern digital relays.

E2.4.3.3 System Resiliency

Over the 2025-2029 period, Toronto Hydro is reintroducing and expanding the work done through the 2015-2019 Overhead Infrastructure Relocation program[59] to improve the resiliency of the overhead system through targeted relocations and/or undergrounding of overhead assets that are vulnerable to power outages during major storm events. Specifically, Toronto Hydro seeks to (i) underground critical sections of overhead infrastructure that are persistently affected by outages caused by external factors; (ii) relocate overhead sections in areas with limited access; and (iii) reconfigure and, if necessary, underground pole lines exiting stations that carry three or more circuits.

By increasing the resiliency of the system, these investments will reduce the impact of outages due to weather events on customers, and as such are responsive to customer reliability priorities as described in Section E2.3.1.2.

E2.4.3.4 IT Software Enhancements

Modernization efforts with respect to the grid and business operations are supported by various IT software investments during the 2025-2029 period, which includes the Advanced Distribution Management System ("ADMS"). For example, while the System Enhancement program deploys SCADA switches on the distribution network, which are critical for distribution automation, IT

[59] EB-2014-0116, Exhibit 2B, Section E6.5

initiatives, such as the implementation of manual Fault Location, Isolation and Service Restoration (FLISR) technology (as part of the broader ADMS project) in 2025-2029, will apply real-time analytics to the operation of these switches to support further reductions in fault isolation and service restoration duration. These investments are also foundational to Toronto Hydro's goal of preparing the Horseshoe grid for the implementation of a fully automated, self-healing grid operation beginning in 2030. More broadly, Toronto Hydro intends to accelerate investment in data quality and governance, system integrations, data analytics, process automation, customer facing tools, and decision-making platforms in 2025-2029 to enhance value for customers and establish the foundations and capabilities for longer-term efficiency and sustainable performance. For more information on enhancements, refer to the Grid Modernization Strategy in Section D5 and the IT Investment Strategy in Section D8.

Over the 2025-2029 period and as part of its broader Modernization efforts, Toronto Hydro also plans to continue to invest in cybersecurity controls to monitor digital threats and ensure a robust response to intensifying risks in this area. The investment plans were developed such that the utility is able to maintain its cybersecurity posture at current levels while developing future state readiness to adapt to the constantly changing cybersecurity threat landscape.

E2.4.4 General Plant Expenditures

Toronto Hydro developed a General Plant expenditure plan leveraging the asset management principles and strategies outlined in Sections D6 ("Facilities Asset Management"), D8 ("IT Asset Management"), and Section E8.3 ("Fleet and Equipment Services"). This plan also supports Toronto Hydro's Net Zero 2040 strategy as set out in Section D7 ("Net Zero 2040"). Investments in this category are necessary to keep the utility running efficiently and effectively and are generally driven by lifecycle cost management principles, business continuity needs, and emerging customer needs and preferences.

Table 6: 2025-2029 General Plant Expenditure Plan ($ Millions)

Capital Program/Segment	Costs
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

Capital Program/Segment	Costs
Information and Operational Technology (Exhibit 2B, Section E8.4)[60]	$206
General Plant Capital	**$467**

E2.4.4.1 Fleet and Facilities

Investments in Facilities Management and Security,[61] and Fleet and Equipment needs are primarily driven by asset obsolescence, condition and lifecycle cost analysis for major work centres, stations buildings, physical security systems, and vehicles.[62]

Investments are also driven by the decarbonization goals set out in the utility's Net Zero 2040 strategy (Section D6). In order to meet these goals, the utility plans to electrify fleet and facilities assets. Specifically, Toronto Hydro intends to reduce emissions from its vehicles and work centres by: (i) replacing gasoline and diesel power vehicles with hybrid and electric vehicles, and (ii) converting natural gas boilers and heaters in the work centres to electric boilers and heaters.

E2.4.4.2 Information and Operational Technology (IT/OT)

The utility's planned IT/OT Systems investments[63] for the 2025-2029 period are primarily directed at maintaining current business capabilities, with the remainder directed at expanding existing business capabilities or driving new ones in alignment with outcome objectives and customer needs. The IT/OT program consists of the following key elements:

- **IT Hardware:** Planned expenditure levels were developed to align with asset lifecycles for backend assets (e.g. servers) and endpoint assets (e.g. laptops) that require replacement, and to meet anticipated business needs as forecasted through business planning.
- **IT Software:** Planned expenditure levels were developed in anticipation of upgrade requirements (i.e. security patches, version upgrades to secure vendor support, etc.) for major IT systems such as the utility's Enterprise Resource Planning ("ERP") and other minor applications. Expenditures also include regulatory compliance needs and a portion of software enhancements to improve and expand business functionality.

[60] *Supra.* note 58.
[61] Exhibit 2B, Section E8.2.
[62] Exhibit 2B, Section E8.3.
[63] Exhibit 2B, Section E8.4.

- **Communication Infrastructure:** Planned expenditure levels were developed to address communications infrastructure that is relied upon by core utility operations to maintain and operate the distribution system in a safe and reliable manner. Proposed investments will address functional obsolescence and reliability risk (e.g. upgrading the communications technology that supports the utility's critical SCADA system), safety and operational risks (i.e. underground radio expansion) and support for system modernization investments (e.g. fibre-optic plant replacement and expansion to support Network Condition Monitoring and Control).

To inform the level of overall IT/OT expenditures, Toronto Hydro procured an independent benchmarking study by Gartner Consulting (see Section D8, Appendix A), which 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 ([…] largely due to the Customer Information System ("CIS") upgrade) and IT Management and Administration ([…] largely due to increased investment in Cyber Security services)."

E2.4.4.3 Enterprise Data Centre

Toronto Hydro's operations are supported by its Enterprise Data Centre ("EDC"), which houses the utility's essential networking, telephony and telecommunications systems, data storage and backup systems and server infrastructure across two distinct locations that collectively support organization-wide ("enterprise") processes. Toronto Hydro will need to store more data within its EDCs as the utility continues to build, maintain, and operate its distribution system in accordance with the evolving needs and nature of load customers, DER owners and operators, and other stakeholders, and as the utility modernizes its systems and practices by introducing new enterprise systems and business processes throughout the 2025-2029 rate period.

Although Toronto Hydro has prudently managed and maintained reliability and operational resilience at its EDC locations through its robust asset management strategy and asset renewal and repair activities,[64] the utility expects that EDC 1 will reach its capacity within the next five years and

[64] Exhibit 2B, Sections D6 (Facilities Asset Management Strategy) and E8.2 (Facilities Management and Security), and Exhibit 4, Tab 2, Schedule 12 (Facilities Management OM&A program).

will no longer be able to accommodate new data and support new systems. As such, Toronto Hydro proposes to relocate EDC 1 to another centre to enhance the overall redundancy and resiliency of the EDC and minimize the risks of an organization-wide outage.

E2.4.4.4 Portfolio Reporting

The Portfolio Reporting element of IPPR directly informed the development of capital program expenditure plans for the 2025-2029 period. In particular, Toronto Hydro analyzed actual project accomplishments and costs in each program to establish the project- and/or volume-based assumptions that would form the basis of the high-level program cost estimates for the 2025-2029 period.[65] Due to the unique nature of work in each capital program (e.g. large discrete assets vs. area rebuilds; like-for-like vs. reconfiguration), Toronto Hydro's planners relied on different estimating approaches for different programs, leveraging both historical information and professional judgement. These assumptions were challenged and refined throughout the IPPR process and business planning.

E2.4.4.5 Capital Program Efficiency and Unit Cost Benchmarking

To assess the actual efficiency with which Toronto Hydro executes its system investment and maintenance programs, the utility retained UMS Group ("UMS") to perform a capital and maintenance unit cost benchmarking exercise. The utility provided UMS with actual, all-in capitalized unit costs for major asset classes for the 2020-2022 period. UMS performed a normalized comparison of these results to those of peer utilities across North America.

Overall, UMS found that Toronto Hydro's unit costs ranged from minus 12.2 percent to plus 1.9 percent relative to the median. These results provide an indication that the utility has delivered its large capital program cost-effectively through rigorous project development, program management, procurement, and execution practices. 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 3, Appendix C.

[65] For many DSP programs, it is practically infeasible to develop project-specific details for a five- to seven-year planning horizon. Planners used a mix of analogous and parametric estimating techniques to create high-level estimates for the programs in these situations. Analogous estimating involves creating a "top-down" estimate of a project's cost and duration using experience with similar projects. Parametric estimating involves identifying volumetric costs and scaling the project or program estimate by the volume of units.

E3 System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources

This section provides information on the capability of Toronto Hydro's distribution system to accommodate renewable energy generation and other distributed energy resource ("DER") connections. This information includes renewable DER applications, overall DER connection projections, the distribution system's ability to connect, as well as known constraints on the distribution system.

E3.1 DER Applications

Since the introduction of the *Green Energy and Green Economy Act, 2009*, Toronto Hydro connected over 2400 DERs under various programs including FIT, HCI, PSUI-CDM, RESOP, HESOP,[1] and Net-Metering. In 2018, the FIT and micro FIT programs ended, and the *Green Energy and Green Economy Act, 2009* was repealed on January 1, 2019. Interest in generation projects within Toronto Hydro's service territory saw a greater than anticipated decrease in renewable pre-assessment applications in the years immediately following the conclusion of the FIT program in 2018. However, customers have continued to show an interest in DER projects, and connections continue to grow, albeit at a slower pace. Toronto Hydro continues to receive applications from a wide range of proponents including, but not limited to, individual residential addresses, public transit facilities, housing developments, large grocery stores, educational facilities, and hospitals.

As of the end of 2022, Toronto Hydro has 2,424 unique DER connections to its distribution grid. Figure 1 provides an overview of existing DER connections within Toronto Hydro's service territory. This represents over 304.9 MW of generation capacity across various types of DER technologies.

[1] Feed-in Tariff ("FIT"); Hydroelectric Contract Initiative ("HCI"); Process and Systems Upgrade Initiative – Conservation Demand Management (PSUI-CDM"); Renewable Energy Standard Offer Program ("RESOP"); and Hydroelectric Standard Offer Program ("HESOP");

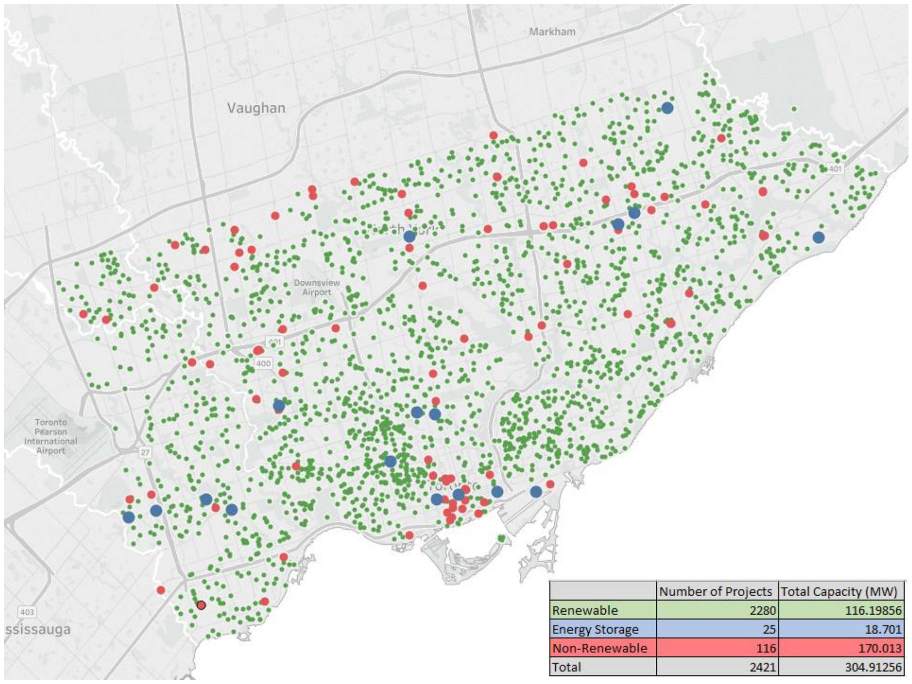

Figure 1: Toronto Hydro DG Connections (as of December 31st, 2022)

From 2018 to 2022, Toronto Hydro connected about 93.2 MW of generation to its distribution system, which represents approximately 22.8 percent of the 408.4 MW connected capacity that was projected for the same time period in the 2020-2024 rate application. The lower than expected DER capacity connected during this period can be attributed to various reasons:

- The conclusion of the FIT program in 2018 led to a greater than anticipated decrease with a 71.9 percent decline in renewable DER pre-assessment applications in the years immediately following the cancellation across residential, commercial & industrial segments.
- Changes in the IESO Process Systems & Upgrade program in 2019 made fossil-fuel based CHP projects ineligible for incentives.
- During the COVID-19 pandemic there was a sharp reduction in applications for pre-assessments for DERs by commercial and industrial businesses. Subsequently, connections fell well below pre-pandemic expectations.
- A number of large projects were placed on hold indefinitely by customers or were cancelled, including, but not limited to, a 9.87 MW biogas generator project, a 15 MW energy storage system, and a 10 MW diesel synchronous generator project.

E3.2 Forecasted DER Connections

Toronto Hydro's 2023-2029 DER connection and capacity forecast considers a combination of historical trends, project pipeline, economic environment and the current energy policies at the time of the forecast.[2] Total DER projects are expected to contribute a total increase of 67 percent to total installations, reaching nearly 4,500 connections by the end of 2029, as shown in Figure 2. This represents a total DER installed capacity of approximately 516.7 MW by the end of 2029 in comparison to the 304.9 MW installed as of the end of December 2022, depicted in Figure 3.

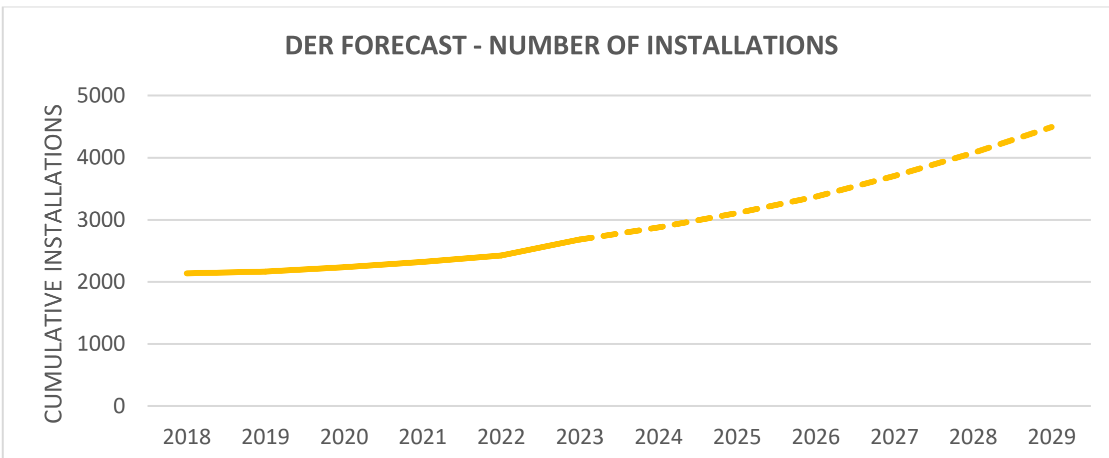

Figure 2: Historical and Forecasted DER Installations

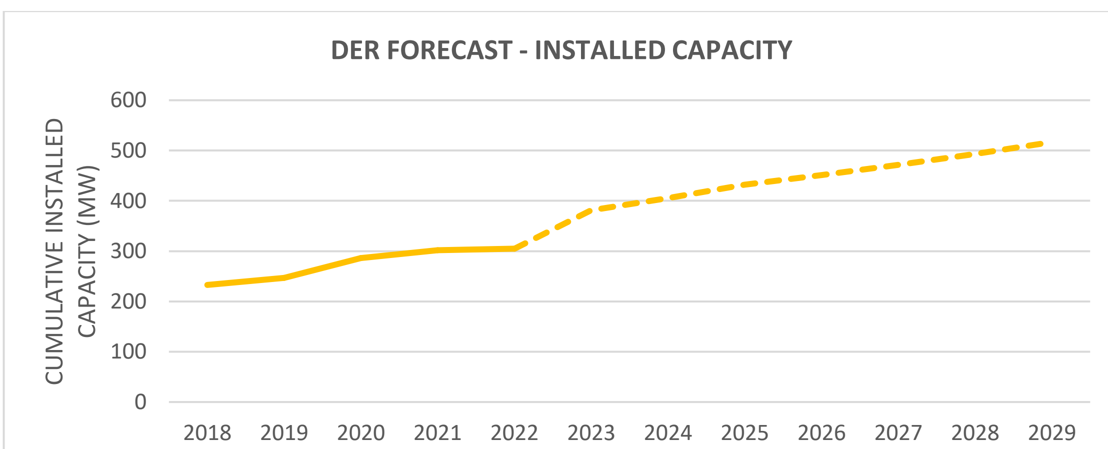

Figure 3: Historical and Forecasted Installed DER Capacity

[2] See Exhibit 2B, Section E5.1.3.2 for further details of Toronto Hydro's DER connection forecast methodology.

Toronto Hydro organizes its DER forecast into renewable, energy storage and non-renewable categories. As of the end of 2022, renewable installations represent the largest category of DER by number of connections while non-renewables represent the largest category by generation capacity. Non-renewable DERs are generally larger capacity connections used to support large commercial or industrial facilities. With more emphasis on decarbonization, it is expected that the combined installed capacity for renewable and energy storage facilities could surpass non-renewables by 2029 as shown in Figure 4.

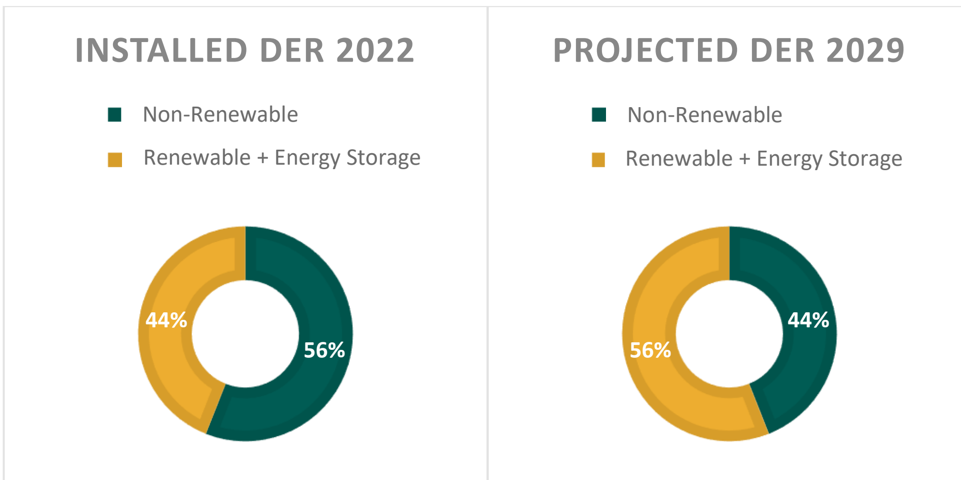

Figure 4: DER Composition by Installed Capacity

E3.2.1 Forecasted Connections for Renewable

Between 2023 and 2029, Toronto Hydro forecasts over 1700 additional renewable connections (totalling over 74 MW) to the distribution system. This would bring total installed capacity to approximately 200 MW as shown in Figure 5. This rate of growth is in alignment with the Ontario Distributed Energy Resources Impact Study conducted by ICF and submitted to the OEB in 2021.[3]

[3] Ontario Energy Board, ICF, Ontario DER Impact Study (January 18, 2021), online, https://www.oeb.ca/sites/default/files/ICF-DER-impact-study-20210118.pdf

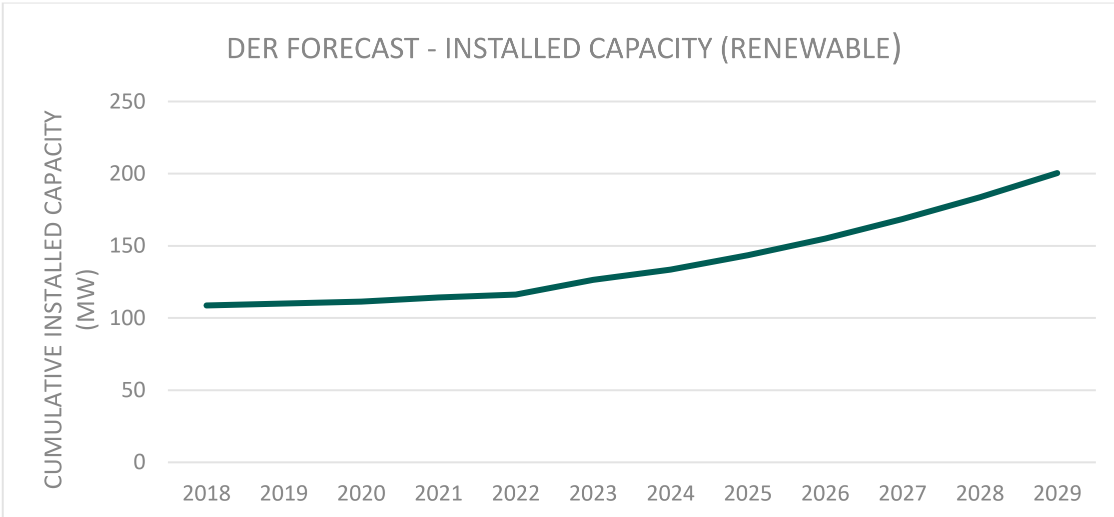

Figure 5: Historical and Forecasted Renewable DER Installed Capacity

E3.2.2 Forecasted Connections for Energy Storage

Although in recent years Toronto Hydro saw a reduced interest in energy storage projects, the utility forecasts a return to high growth by the end of decade. As of the end of 2022, Toronto Hydro connected 28 energy storage projects with total generating capacity of 18.7 MW, the vast majority of which are used in commercial and industrial applications, including for the reduction of global adjustment charges. Toronto Hydro's current energy storage project pipeline anticipates the connection of 12 projects by the end of the year with a combined capacity of 31.9 MW.

Beyond 2025, Toronto Hydro expects that energy storage growth will return to linear growth patterns, similar to pre-pandemic levels. Between 2023 and 2029, Toronto Hydro forecasts over 50 additional energy storage connections (totalling over 70.8 MW) to the distribution system. This would increase the total number of connections to 82 by 2029, and the total installed energy storage capacity to 89.5 MW, as depicted in Figure 6.

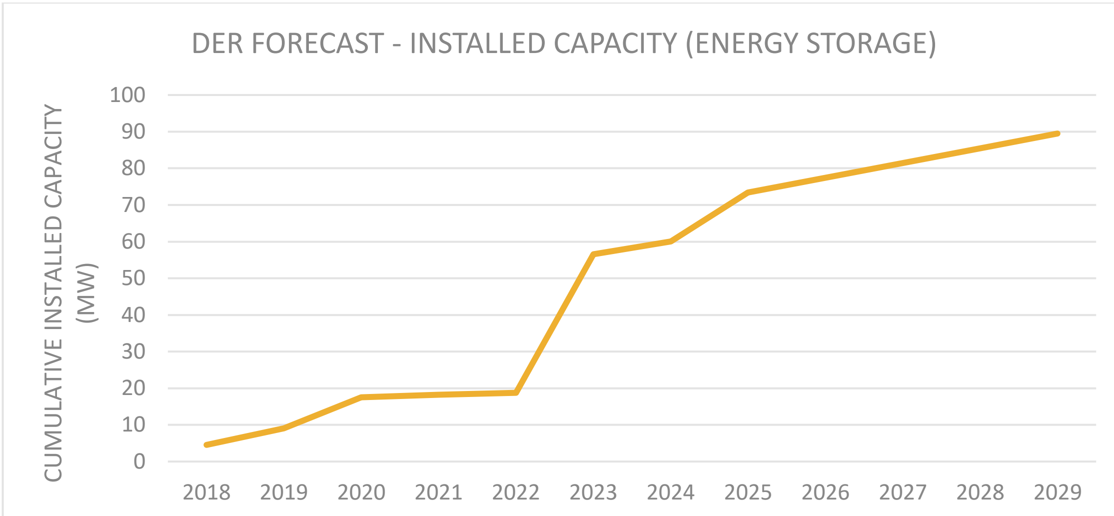

Figure 6: Historical and Forecasted Energy Storage Capacity

E3.2.3 Policy Considerations

Customer choice is the key driver of DER demand, and this driver can be greatly impacted by policy, including the available funding and incentives. The FIT program is a testament to the significant impact that policy and incentives can have on the renewable DER uptake by customers. Between 2009 and 2018 when the FIT program was active, DER installed capacity increased from 1.4 MW to 108.7 MW—a compound annual growth rate of 62.2 percent. When the FIT program ended, the renewable energy annual average growth rate fell to 1.7 percent over 2018 to 2022.

Policies and economic factors that may impact the rate of renewables and energy storage connections include:

- **Green Energy Tax Credit –** Announced by the Federal Government in November 2022, the Green Energy Tax Credit is a refundable credit of up to 30 percent of the capital cost of investments in specific generation systems, including solar PV and battery storage systems.[4]
- **Third Party Ownership of Net Metered Generation Facilities –** On July 1, 2022, the OEB enacted changes to enable third-party ownership of Net Metered generation facilities,

[4] Environment and Climate Change Canada, Clean Investment Tax Credits in Budget 2023, "online", https://www.canada.ca/en/environment-climate-change/news/2023/04/minister-guilbeault-highlights-the-big-five-new-clean-investment-tax-credits-in-budget-2023-to-support-sustainable-made-in-canada-clean-economy.html

opening up access to the program for customers who may not be in a position to own or operate their own behind-the-meter renewable energy generating equipment.[5]

- **Lithium Ion Battery Cost** – Lithium Ion battery prices have decreased by more than 79 percent since 2013 and are expected to continue to decrease.[6] The combination of solar PV and energy storage allows users to maximize the use of solar PV generated energy that can only be captured during the day.
- **Ultra-Low Overnight Price Plan** – In 2023, Ontario launched an "Ultra-Low" (ULO) overnight price plan for residential and small business customers. The ULO plan offers an overnight rate of 2.4 cents per kWh (down from 7.4 cents)[7] providing an incentive for storing energy overnight and discharge it during the day when the price is higher.
- **Industrial Conservation Initiative (ICI) program** – Commercial and industrial customers who opt into the Industrial Conservation Initiative (ICI) program can reduce their global adjustment charges through peak shaving using energy storage systems.

The timing, impact and probability of customer demand is subject to a host of policy, economic and technology factors that are difficult to predict. While Toronto Hydro considered the programs and incentives that are currently available to customers in preparing its DER forecast, actual growth rates could materially differ from what the forecast anticipates if new programs or incentives become available.[8] As such, the utility needs flexibility to adapt its plans in response to external factors which could drive up greater customer demand for renewables or energy storage. To enable this flexibility over the 2025-2029 rate period, Toronto Hydro's Custom Rate Framework proposes a mechanism known as the Demand Related Variance Account (DRVA). For more information about the DRVA, please refer to Exhibit 1B, Tab 2, Schedule 1.

[5] Ontario Energy Board, Forms and Templates: Third-Party Net Metering and Energy Contracts , "online", https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/forms-and-templates-third-party-net

[6] BloombergNEF, Lithium-ion Battery Pack Prices Rise for First Time to an Average of $151/kWh, "online", https://about.bnef.com/blog/lithium-ion-battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/#:~:text=LFP%20battery%20pack%20prices%20rose,cell%20prices%20observed%20in%202022

[7] https://news.ontario.ca/en/release/1002916/ontario-launches-new-ultra-low-overnight-electricity-price-plan

[8] See, for example, the Future Energy Scenarios Report where consumer choice modelling of the uptake scenarios for rooftop solar PV showed a range of installed capacity by 2050 of between 400 MW to 1,200 MW; Exhibit 2B, Section D4, Appendix B – *Future Energy Scenarios Report* at pages 67-70.

E3.2.4 Forecasted Connections for Non-Renewable

Toronto Hydro's pipeline for non-renewable DER currently consists of 8 projects, totalling 26.6 MW expected to be connected in 2023. Between 2023 and 2029, Toronto Hydro forecasts 28 additional non-renewable DER connections (totalling over 56.8 MW) to the distribution system. This would bring total installed non-renewable DER capacity to 226.8 MW as shown in Figure 7.

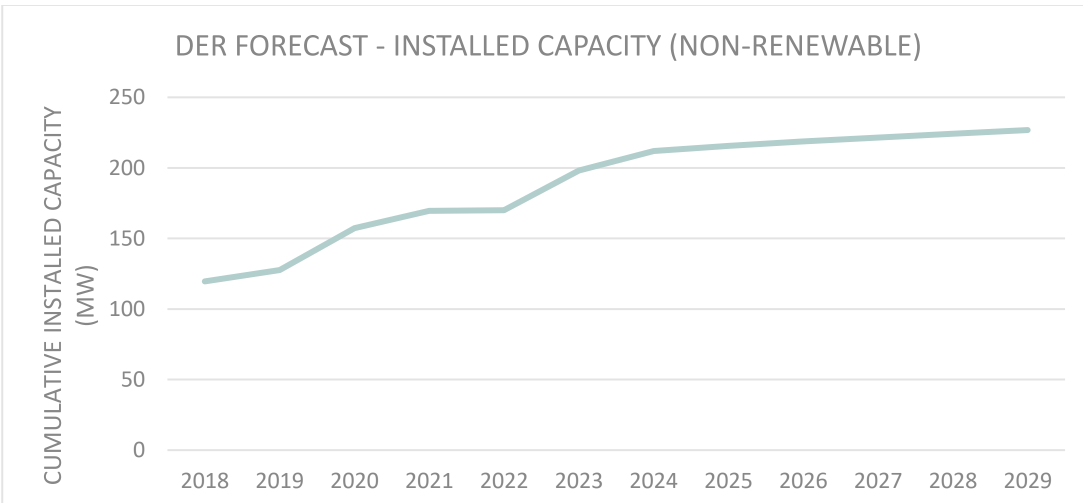

Figure 7: Historical and Forecasted Non-Renewable Capacity

While Toronto Hydro anticipates government policy to gradually reduce the use of non-renewable sources of energy in the journey to reaching net zero goals, the most common applications of non-renewable DER do not yet have viable or technologically mature alternatives. For example, gas generators remain a preferred method of backup generation as they can run for long periods of time in the event of a prolonged outage. Non-renewable generation is also used for Combined Heat and Power (CHP) systems which can generate both heat and electricity.

E3.3 System Capability to Connect DER

Toronto Hydro's system capability to connect renewable DER facilities is subject to a number of considerations, including short-circuit capacity, the risk of islanding, thermal limits, and the inability to transfer loads between feeders during planned work. Each of these considerations is described in greater detail below.

1. Short Circuit Capacity Constraints

To maintain safe and reliable operation of the distribution system, Toronto Hydro cannot connect DERs in situations where short circuit capacity limitations exist. Short circuit capacity is electrical system or component's capacity to withstand without permanent damage, high levels of electrical energy congregating on that point or location. Figure 8 below is a map which shows the areas within Toronto's grid that are approaching, or have reached, short circuit limits at various stations. These stations are supplied by Hydro One Networks Inc. transformers and directly connect to Toronto Hydro feeders.

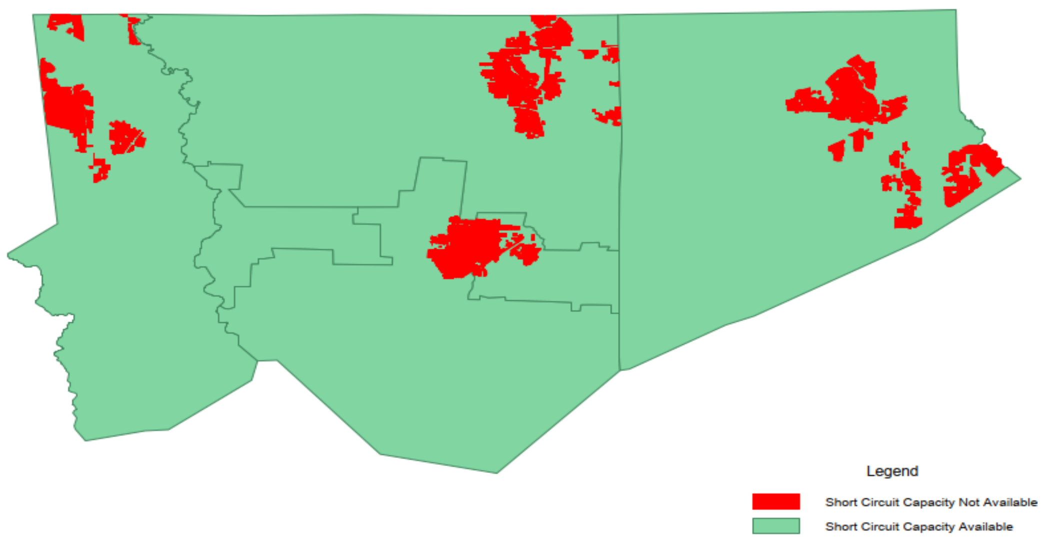

Figure 8: Map of Distribution System Short Circuit Capacity Constraints

Toronto Hydro maintains a list of restricted feeders on its website that is updated every 3 months in accordance with section 6.2.3 (g) of the Distribution System Code. As of July 2023, Toronto Hydro has five transformer station bus pairs that are restricted leading to 48 total restricted feeders due short circuit capacity constraints, as outlined in Table 1 below.

Table 1: Restricted Feeders and Number of Connected Customers

Station Name	Feeder Designation	Restriction	No. of Connected Customers
Sheppard TS, Bus EZ	47-M4	Short Circuit Capacity	0
	47-M6	Short Circuit Capacity	3378
	47-M1	Short Circuit Capacity	3952

Station Name	Feeder Designation	Restriction	No. of Connected Customers
	47-M5	Short Circuit Capacity	0
	47-M2	Short Circuit Capacity	0
	47-M8	Short Circuit Capacity	618
	47-M7	Short Circuit Capacity	1293
	47-M3	Short Circuit Capacity	5909
Woodbridge TS, Bus BY	D6-M1	Short Circuit Capacity	662
	D6-M2	Short Circuit Capacity	0
	D6-M3	Short Circuit Capacity	0
	D6-M4	Short Circuit Capacity	322
	D6-M5	Short Circuit Capacity	0
	D6-M6	Short Circuit Capacity	0
Leslie TS, Bus BY	51-M1	Short Circuit Capacity	0
	51-M3	Short Circuit Capacity	1794
	51-M5	Short Circuit Capacity	1065
	51-M7	Short Circuit Capacity	5663
	51-M2	Short Circuit Capacity	0
	51-M4	Short Circuit Capacity	625
	51-M6	Short Circuit Capacity	2196
	51-M8	Short Circuit Capacity	2582
Leaside TS, Bus AQ	A-5-L	Short Circuit Capacity	54
	A-6-L	Short Circuit Capacity	30
	A-10-L	Short Circuit Capacity	65
	A-12-L	Short Circuit Capacity	1990
	A-13-L	Short Circuit Capacity	1934
	A-16-L	Short Circuit Capacity	5
	A-17-L	Short Circuit Capacity	32
	A-21-L	Short Circuit Capacity	2058
	A-22-L	Short Circuit Capacity	2623
	A-26-L	Short Circuit Capacity	34
	A-1-L	Short Circuit Capacity	0
	A-3-L	Short Circuit Capacity	6

Station Name	Feeder Designation	Restriction	No. of Connected Customers
	A-28-L	Short Circuit Capacity	10
	A-2-L	Short Circuit Capacity	0
	A-4-L	Short Circuit Capacity	12
	A-27-L	Short Circuit Capacity	20
	A-14-L	Short Circuit Capacity	2019
Richview TS, Bus BY	88-M1	Short Circuit Capacity	90
	88-M3	Short Circuit Capacity	127
	88-M5	Short Circuit Capacity	0
	88-M7	Short Circuit Capacity	0
	88-M2	Short Circuit Capacity	1651
	88-M4	Short Circuit Capacity	0
	88-M6	Short Circuit Capacity	0
	88-M8	Short Circuit Capacity	49

Toronto Hydro is working with Hydro One to mitigate these restrictions by re-examining feeder limits and making planned investments in bus tie reactors as part of the Generation Protection Monitoring and Control (GPMC) program at Exhibit 2B, Section E5.5.

2. Anti-Islanding Condition for DER

Islanding occurs when a DER source continues to power a portion of the grid even after the main utility supply source has been disconnected or is no longer available. This situation must be avoided as it can interfere with grid protection systems and pose a serious safety risk to crews who perform work on Toronto Hydro's system. To safeguard against this risk, the connection of photovoltaic solar inverters and other DER sources must prevent unintentional islanding, as per IEEE 1547.2/D6.5, August 2023 (Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces).[9] Toronto Hydro plans to continue to deploy real-time monitoring and control investments at every new DG site to protect against the risk of islanding. For more information please refer to the GPMC program at Exhibit 2B, Section E5.5.

[9] "IEEE Draft Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," in IEEE P1547.2/D6.5, August 2023, vol., no., pp.1-322, 11 Aug. 2023 ("IEEE P1547.2/D6.5").

As the ratio of generation capacity to minimum load on a feeder increases, the amount of time required by inverters to respond to anti-islanding scenarios also increases and the effectiveness of inverter response to anti-islanding scenarios decreases. Based on common industry practice[10] Toronto Hydro aims to ensure that "DR aggregate capacity is less than one-third of the minimum load of the Local Electric Power System (EPS)"[11] – i.e. minimum generation to load ratio (MLGR).

Toronto Hydro conducted an analysis for all feeders in its system to establish MLGR in accordance with applicable guidance found in IEEE-P1547.2/D6.5, August 2023.[12] The results of study, summarized in Table 2 below, show that 23 feeders are below the recommended ratio, and that by 2029 an additional 24 feeders could be below the ratio based on the DER forecast for renewables.

Table 2: MLGR Feeder Analysis

Station	Feeder Name	Nameplate Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Min. Load (MW)	Current MLGR	MLGR Forecast 2029	REG Cx Enabled (MW)
Agincourt TS	63-M6	3.530	100.0%	5.77	7.10	2.011	1.230	2.24
Finch TS	55-M31	1.750	100.0%	2.95	3.52	2.011	1.193	1.20
Fairbank TS	35-M8	1.997	83.0%	2.80	5.50	2.753	1.750	1.15
Rexdale TS	R29-M1	1.115	100.0%	1.94	2.54	2.275	1.305	0.83
Horner TS	R30-M3	0.760	100.0%	1.38	1.91	2.519	1.387	0.62
Scarborough TS	E5-M24	3.712	16.5%	1.15	4.12	1.109	0.969	0.53
Horner TS	R30-M10	4.573	12.5%	1.08	5.12	1.120	1.007	0.51
Bathurst TS	85-M6	6.761	7.5%	0.98	5.56	0.822	0.768	0.47
Bathurst TS	85-M30	5.250	9.5%	0.97	2.83	0.539	0.495	0.47
Finch TS	55-M32	1.508	33.2%	0.97	4.09	2.712	2.069	0.47
Leslie TS	51-M25	1.677	25.5%	0.85	4.88	2.911	2.322	0.43
Finch TS	55-M29	1.914	21.7%	0.83	4.22	2.205	1.809	0.42
Fairchild TS	80-M10	1.300	23.1%	0.65	2.69	2.069	1.629	0.35
Leslie TS	51-M23	2.100	14.3%	0.65	4.58	2.181	1.868	0.35

[10] R. Seguin, et. al., *High-Penetration PV Integration Handbook for Distribution Engineers*, NREL/TP-5D00-63114 (2016), "online", https://www.nrel.gov/docs/fy16osti/63114.pdf
[11] IEEE P1547.2/D6.5.
[12] "IEEE Draft Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," in IEEE P1547.2/D6.5, August 2023 , vol., no., pp.1-322, 11 Aug. 2023.

Station	Feeder Name	Nameplate Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Min. Load (MW)	Current MLGR	MLGR Forecast 2029	REG Cx Enabled (MW)
Bathurst TS	85-M7	6.105	1.7%	0.34	2.62	0.429	0.413	0.24
Bathurst TS	85-M1	6.013	0.2%	0.20	6.86	1.141	1.107	0.18
Finch TS	55-M2	5.300	0.0%	0.18	2.96	0.558	0.541	0.18
Bathurst TS	85-M32	4.750	0.0%	0.18	6.08	1.280	1.234	0.18
Windsor TS	A-61-WR	1.500	0.0%	0.18	2.75	1.835	1.642	0.18
Esplanade TS	A-39-X	7.000	0.0%	0.18	14.50	2.072	2.021	0.18
George Duke TS	A-45-GD	1.050	0.0%	0.18	2.18	2.074	1.776	0.18
Fairchild TS	80-M23	0.900	0.0%	0.18	2.12	2.356	1.970	0.18
Cecil TS	A-41-CE	1.275	0.0%	0.18	3.37	2.646	2.326	0.18

To address islanding concerns and enable safe connection of renewable DERs on feeders with a high generation to load ratio, an energy storage system (ESS) can be installed on the feeder to act as a load to manage MLGR when the minimum load is low. For more information, please refer to the Renewable Battery Energy Storage System segment of the Non-Wires Solutions program at Exhibit 2B, Section E7.2.

3. System Thermal Limits and Load Transfer Capability

For large generation, or aggregated generation, an important operating limit stems from a feeder's continuous load thermal ratings. Exceeding system thermal limits adversely affects the lifespan of distribution equipment and can cause immediate equipment failure. Monitoring and control equipment allows Toronto Hydro to monitor and mitigate feeder thermal loading.

In undertaking feeder planning and operations, Toronto Hydro considers the system impact of the generator being online versus offline. The aforementioned thermal ratings affect the variability of various generation sources, system load growth, and the occurrence of contingencies, as thermal limits are indicative of the grid's equipment withstand capabilities. Since contingencies and feeder planned work occur particularly on feeder load transfers, it is imperative to assess the relative impact DER would impose particularly those larger capacity generators. Real-time monitoring and control would provide this window of information.

E3.3.1 Planned Investments to Eliminate Constraints

In order to connect the forecasted DERs to Toronto Hydro's distribution system, the following solutions have been identified as planned investments for the 2025 to 2029 period:

1) Six bus-tie reactors to alleviate short circuit capacity constraints at stations that cannot be relieved through station expansion work or by increasing station equipment thresholds. Table 3 below identifies the station buses where bus tie reactors are proposed.

Table 3: Locations of Proposed Bus Tie Reactors (2025-2029)

Station Name	Bus	2023 Available Short Circuit Capacity (MVA)	2029 Available Short Circuit Capacity (MVA)
Cecil	CE-A1A2	59.7	-32.7
Esplanade	X-A1A2	58.9	-7.6
Leslie	51-BY	3.2	-46.6
Richview	88-BY	-40.3	-41.2
Runnymede	11-JQ	113.6	-103.3
Woodbridge	D6-BY	-27.3	-28.0

2) Real-time monitoring and control systems must be installed at every site to monitor for islanding and thermal conditions.[13] In accordance with the Distribution System Code, monitoring and control systems for renewables are paid for by the distributor rather than the customer as is the case for non-renewables.
3) Toronto Hydro plans to deploy nine energy storage systems, with an aggregate capacity of 10.2 MW, to enable the connection of forecasted renewable growth on the nine high-priority feeders outlined in Table 3 above. The utility selected these feeders based on their existing high renewable DER penetration, low MLGR ratio and high forecasted renewable DER growth. Please refer to the Non-Wires Solutions program for more information about the feeder selection process and analysis (Exhibit 2B, Section E7.2).

[13] Exhibit 2B, Section E5 – Generation Protection and Control, section E5.5.4.2.

E4 Capital Expenditure Summary

This section provides an overview of Toronto Hydro's capital and system maintenance and operational (O&M) expenditures for the 2020-2029 rate period, including explanations of: (i) variances in forecast expenditures from the 2020-2024 capital plan versus actual expenditures during over the 2020-2024 rate period, and (ii) shifts in 2025-2029 forecast expenditures versus 2020-2024 historical expenditures by investment category.

The explanations provided in this section are complimentary to the information presented in OEB Appendices 2-AB,[1] and 2-AA which are appended to this section.[2] Detailed explanations for material variances and trends are also provided within the 'Expenditure Plan' section of each capital program in sections E5 to E8.

Accounting Treatment for CWIP

Expenditures for capital projects that span more than one calendar years are recorded in a Construction Work-in Progress ("CWIP") account until the project work is completed. Given the nature of its capital expenditure programs and projects, at any point in time, Toronto Hydro has a balance in the CWIP account. Initial capital expenditures are recorded in CWIP until the project is complete, and capitalized. Under Modified International Financial Reporting Standards ("MIFRS"), a financing charge, referred to as Allowance for Funds Used During Construction ("AFUDC"), is added to capital projects that exceed six months to complete. AFUDC is part of Other Capital Expenditures as further explained below.

Other Capital Expenditures

Toronto Hydro's capital expenditures under the Other Capital Expenditures category includes Allowances for Funds Used During Construction ("AFUDC") and miscellaneous capital, as described in OEB Appendices 2-AB.[3]

- AFUDC is capitalized in accordance with the OEB's Accounting Procedures Handbook, Article 410. The AFUDC rate applied by Toronto Hydro under MIFRS for 2020 to 2022 actuals, 2023

[1] Exhibit 2B, E4, Appendix A
[2] Exhibit 2B, E4, Appendix B
[3] *Supra* note 1.

to 2024 bridge, and 2025 to 2029 forecast years is based on Toronto Hydro Corporation's weighted average cost of borrowing.

- Miscellaneous capital primarily consists of pre-capitalized inventory and major tools. The value of pre-capitalized inventory results from the change in capitalized inventory levels between years.[4] The utility purchases major tools in the normal course of operations and on an ongoing basis to replace worn or broken tools, as required, and to install, commission and otherwise complete capital activities.

E4.1 Plan versus Actual Variances for 2020-2024

In Toronto Hydro's 2020-2024 rate application, the OEB approved a custom incentive rate-setting mechanism on the basis of a capital expenditure plan of $2,710.7 million.[5]

Due to the imposition of a 0.9% 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.

[4] Ontario Energy Board, *Accounting Procedures Handbook for Electricity Distributors*, (January 1, 2012), Article 410.
[5] EB-2018-0165, Draft Rate Order (Filed: January 21, 2020; Updated: February 23, 2020), Schedule 4 – Capital Expenditures.

- Staying on track to complete Copeland TS – Phase 2 project and the Control Operations Reinforcement program on time within budget.

As described in Section D1, Toronto Hydro goes through an extensive annual business planning process to strike a balance across these objectives. To ensure the utility was able to meet specific needs of the system (including those listed above) and manage within the operating conditions of the current period (including 40-year high inflation), Toronto Hydro had to reduce the pacing of certain system renewal investments: [6]

- the replacement of direct-buried cables as part of its Underground System Renewal – Horseshoe program;[7] and
- the replacement of wood poles in its Overhead System Renewal program.[8]

Reduction in these programs placed additional pressure on reliability performance. Toronto Hydro had to carefully manage these pressures to honour its commitment to maintain reliability performance over this period and meet other key plan objectives noted above. The utility succeeded in this balancing act as it:

- maintained reliability performance relatively consistent over its historical average. The utility's SAIDI performance improved over the last five years (2018-2022), averaging 0.85 hours and exceeding the OEB's distributor target of 0.87 hours. The utility's SAIFI performance is slightly worse than the OEB's distributor target of 1.20, averaging at 1.30 during 2018 to 202, but comparable to the 2013-2022 average of 1.28;
- Connected approximately 10,000 customers through the Customer Connections program, with an increase of $147.5 million (71 percent) in capital expenditures over the forecast to maintain and exceed performance;
- Continued to support expansion and relocation projects as part of the Externally Initiated Plant Relocations and Expansion program including but not limited to the Metrolinx GO expansion project and the TTC initiated Easier Access Program;
- Reduced constraints on the system through the Load Demand program by alleviating 131 MVA on highly loaded buses, reducing the number of highly loaded feeders by 10, improving

[6] As described in detail in Exhibit 1B, Tab 3, Schedule 3, these include COVID-19, extraordinary inflation, and workforce challenges.
[7] Exhibit 2B, Section E6.4.
[8] Exhibit 2B, Section E6.6.

the civil infrastructure associated with station expansion of five Terminal Stations as well as civil rebuild at the distribution level, and maintaining the number of feeders subject to switching restrictions during the summer months to under 10;

- Replaced of approximately 50,000 residential, small commercial, and industrial meters as part of the AMI 2.0 project in the Metering program over the rate period which improves billing accuracy, faster outage response, improved network range, enhanced cyber security protection, increased grid transparency, data granularity and analytical capabilities;[9]
- Completed installations of radio communication link equipment required to facilitate the two-way communication flow between DER facilities and the Toronto Hydro Control Centre at more than 100 sites during the period of 2020 to 2023;
- Replaced 444 box-framed poles with an additional 236 anticipated over the rate period, enabling the utility to meet its commitment to remove box construction poles from the system by 2026;
- Converted 384 customers from aging rear lot service to safer and more reliable front lot underground during 2020 to 2022, and is on track to convert approximately 299 rear lot customers during 2023 to 2024;
- Addressed approximately 3,500 transformers containing or at risk of containing PCBs with upward pressure on the cost of materials attributed to supply chain issues from the COVID-19 pandemic through a combination of inspection and replacement over the course of 2020-2022;
- Addressed aging and failure risk prone direct-buried cable in the underground system through replacement of 79 kilometers of direct-buried cable over 2020-2023 for an estimated total of 105 kilometers by the end of the rate period;
- Continued to address obsolete PILC and AILC cable through the Underground Renewal – Downtown program by replacing an estimated 30 circuit-km of PILC cable and 9 circuit-km of AILC over the 2020-2024 rate period;[10]
- Addressed deteriorated and non-submersible units through the investments in the Network System Renewal program by replacing 82 network units and an additional 95 network units by the end of the rate period;[11]

[9] Exhibit 2B, Section E5.4.
[10] Exhibit 2B, Section E6.3.
[11] *Supra* note 8.

- Improved flexibility of the system through investments in the System Enhancements program that includes the addition of tie points, sectionalizing points and upgrades to undersized loops, and installation of switchgear ties between Copeland and Windsor stations;[12]
- Continued to advance capabilities and build upon progress from the previous rate period through Local Demand Response initiatives outlined in the Non-Wires Solutions program (E7.2) by targeting Manby TS and Horner TS over the 2020-2024 period;
- Commissioned 379 vaults with an additional 320 over the rate period to modernize just under 90 percent of the secondary network through the Network Condition Monitoring and Control ("NCMC") program,[13] achieving sustained operating expenditure savings and improved network resiliency; and gaining crucial organization grid modernization experience that will be applied to the 2025-2029 rate period;
- Increase the capacity of Copeland Station with a Phase 2 expansion that provides an addition 144MVA to support the growth and development of Central Waterfront area and enhance reliability and resiliency in the downtown core. This project is on time and below budget by approximately $5 million.[14]
- Improving operational resilience and strengthening system security by completing construction of a dual Control Centre by the end of 2023; and
- Improving cyber security and business efficiency and laying the foundation for future customer experience enhancements by upgrading the Customer Information System ("CIS") to a modern, vendor-supported version by Q2 of 2024.

Toronto Hydro forecasts $2,787.4 million in net capital expenditures over the completion of the 2020-2024 rate period, which is three percent higher than the $2,710.7 million approved by the OEB in the 2020-2024 DSP.

In Table 2 below, Appendix 2-AB, and throughout the remainder of this section, Toronto Hydro refers to the OEB Approved values for 2020-2024 as the "Plan" for 2020-2024. By comparing the 2020-2024

[12] Exhibit 2B, Section E7.1.
[13] Exhibit 2B, Section E7.3.
[14] Copeland Phase 2 savings are derived from continuous improvement in execution based on the utility's experience and lessons learned from Copeland Phase 1. For example, more cost-effective procurement agreements for major equipment.

plan to the actual and forecasted bridge year expenditures, the utility is able to provide a complete picture of the management and execution of the current plan.

Table 2 below provides a breakdown of the Plan and of actual plus bridge expenditures by year and by category, and the subsections that follow the table provide explanations for each category:

Table 2: 2020-2024 Capital Expenditure Summary ($ Millions)

OEB Category	Historical									Bridge					
	2020			2021			2022			2023			2024		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	For.	Var.	Plan	For.	Var.
System Access	164.9	225.2	37%	193.0	240.7	25%	184.7	244.3	32%	197.4	260.5	32%	211.1	289.6	37%
System Renewal	290.5	261.7	(10%)	307.2	247.3	(19%)	304.7	276.6	(9%)	319.4	314.0	(2%)	309.5	358.8	16%
System Service	34.6	33.4	(3%)	60.1	68.0	13%	71.3	67.1	(6%)	33.6	32.8	(2%)	38.5	24.3	(37%)
General Plant	78.8	56.1	(29%)	92.8	72.4	(22%)	88.1	112.9	28%	76.8	96.5	26%	84.4	80.7	(4%)
Other	5.3	17.5	232%	6.5	4.8	(26%)	8.9	12.8	44%	6.3	12.6	100%	5.7	7.7	35%
Total CAPEX	**574.1**	**593.9**	**3%**	**659.6**	**633.3**	**(4%)**	**657.7**	**713.7**	**9%**	**633.5**	**716.4**	**13%**	**649.3**	**761.2**	**17%**
Capital Contributions	(74.8)	(145.8)	95%	(102.7)	(100.1)	(2%)	(93.9)	(115.8)	23%	(94.5)	(133.4)	41%	(97.6)	(135.9)	39%
Net CAPEX	**499.2**	**448.1**	**(10%)**	**556.9**	**533.2**	**(4%)**	**563.8**	**597.9**	**6%**	**539.1**	**582.9**	**8%**	**551.7**	**625.3**	**13%**
System O&M	126.3	117.1	(7%)	-	117.5	-	-	124.1	-	-	127.1	-	-	135.0	-

Note: Capital contributions include contributions made by customers and third-parties.

E4.1.1 System Access 2020-2024 Variance Analysis

From 2020 to 2024, System Access expenditures are forecasted to be approximately 33 percent higher than planned due to the following factors:

- Expenditures in the Customer Connections program are forecasted to be approximately 55 percent higher than the plan on a gross basis and 71 percent higher on a net basis.[15] This program is highly volatile and driven by various external factors (e.g. size and location of connections, available capacity provisions, economic drivers). Toronto Hydro experienced a higher than anticipated increase in system access requests for large projects (greater than 5MVA demand) over this period. The increases in 2021-2022 were attributed to the unforeseen emergence of large connections across a broad spectrum of market segments including: multi-use projects (commercial-condominium), institutional infrastructure, industrial infrastructure, data centres, and transit projects (Finch West LRT). Toronto Hydro factored in these trends in developing its 2025-2029 forecasts. See the Customer Connections program for additional details.

[15] Exhibit 2B, Section E5.1.

- Expenditures in the Load Demand program are forecasted to be approximately 38 percent higher than planned.[16] This variance was driven by the need for load transfers between stations and feeders to alleviate system constraints. Like Customer Connections, the Load Demand program can vary significantly from one year to the next due to expected new connections, voltage conversions, and an updated station load forecast. To keep up with these drivers, the Load Demand program forecast is re-evaluated annually.
- Expenditures in the Externally Initiated Plant Relocations and Expansions program are forecasted to be approximately 18 percent higher than planned due to an increase in the volume and complexity of third-party relocation and expansion projects.[17]
- Expenditures in the Metering Program are forecasted to be 34 percent lower than planned. Due to procurement delays and funding constraints, Toronto Hydro adjusted the pacing of meter replacements in the current rate period.[18]

E4.1.2 2020-2024 Variances: System Renewal

From 2020 to 2024, System Renewal expenditures are forecasted to be approximately 5 percent lower than planned due to the following factors:

- Expenditures in the Area Conversions program are forecasted to be approximately 24 percent higher than planned.[19] The net increase in the program is driven by the Box Construction Conversion segment, which saw higher spending due to required shifts in project scheduling as well as incremental cost pressures related to the complexity of the work and various external cost drivers (e.g. coordination with the CafeTO program). For more details, please refer to section E6.1.4.2. The Rear Lot Conversion investments also saw a slight increase of approximately 4 percent.
- Expenditures in the Underground System Renewal – Horseshoe,[20] and Underground System Renewal – Downtown are forecasted to be approximately 24 percent lower than planned.[21] Through its planning and execution process, Toronto Hydro determined that it was necessary to constrain investment in these programs in order to manage funding pressures and balance

[16] Exhibit 2B, Section E5.3.
[17] Exhibit 2B, Section E5.2.
[18] *Supra* note 9.
[19] Exhibit 2B, Section E6.1.
[20] Exhibit 2B, Section E6.2.
[21] *Supra* note 10.

the attainment of multiple objectives within the plan. The utility temporarily shifted its execution strategy to a target spot replacement approach focused on PCB removals, which meant taking on incremental risk in its aging cable population. That accumulation asset failure risk is driving the need for incremental investment in key underground assets such as cables in 2025-2029. In Downtown program, Toronto Hydro was able to find some savings over the 2020-2024 rate period by engineering an alternative approach to cable renewal work which leverages existing available civil infrastructure to the extent possible.

- Expenditures in the Overhead System Renewal program are forecasted to be approximately 18 percent lower than planned due to the same considerations,[22] as discussed above for the Underground Renewal program. Toronto Hydro managed a reduced pace in this program by temporarily shifting its execution strategy to a spot replacement approach focused on PCB removals, and deferring larger area rebuilds to address deteriorating poles and switches as well as obsolete 4 kV feeders.
- Expenditures in the Network System Renewal program are forecasted to be approximately 26 percent higher than planned.[23] The increase is driven in large part by design and execution complexities that emerged as the projects matured from conceptual to detailed design. This includes additional scope of work (e.g. civil construction and legacy cable removal), material cost increases driven by supply chain disruptions, and work execution challenges related to field conditions (e.g. urban congestion) and operational complexities (e.g. coordination challenges).
- Expenditures in the Stations Renewal program are forecasted to be approximately 23 percent higher than planned due to project complexity, necessary scope increases, and inflationary cost escalations.[24]

E4.1.3 2020-2024 Variances: System Service

From 2020 to 2024, System Service expenditures are forecasted to be approximately five percent lower than planned due to the following factors:

[22] Exhibit 2B, Section E6.5.
[23] *Supra* note 7.
[24] *Supra* note 8.

- Expenditures in System Enhancements program are forecasted to be approximately 5 percent lower than planned.[25] Toronto Hydro constrained the pace of investment in this area by deferring work to the 2025-2029 rate period and by leveraging opportunities to carry out some of the planned enhancement work within related renewal programs.
- Expenditures in the Energy Storage Systems (ESS) segment, which has been re-mapped to the Non-Wires Solutions program, are forecast to be 79 percent lower than planned due to challenges in finding a cost-effective site for an ESS installation, as well as supply chain constraints. Faced with these challenges, and further studying the use cases and the regulatory considerations of ESS as a grid-asset Toronto Hydro decided to evolve its ESS investment strategy to focus on enablement of renewables electricity generation resources.[26]

Phase 2 of Copeland TS is expected to be completed in early 2024, therefore, there are no expansion costs forecast for the 2025-2029 rate period. 2020-2024 expenditures are forecast to be about 1 percent higher than planned. For further details, please refer to Stations Expansion program.[27]

E4.1.4 2020-2024 Variances: General Plant

From 2020-2024, General Plant expenditures are forecasted to be aligned with the Plan, as a result of variances in the following programs offsetting each other:

- Expenditures in the Facilities Management and Security program are forecasted to be 41 percent higher than planned due to need for additional unplanned reactive asset replacements, such as the replacement of a failed HVAC unit at the 14 Carlton work centre, the installation of hatchway railings and safety devices, and physical security enhancements in response to security incidents; incremental work to reduce building emissions;, and overall higher costs of materials and labour driven by supply chain disruptions and inflationary pressures in the construction industry.[28]
- Expenditures in the IT/OT program are forecasted to be 8 percent lower than planned. Increases in cybersecurity investments required to reinforce system protection due to an increase in external threats were offset by savings resulting from the prudent decision to

[25] *Supra* note 12.
[26] Exhibit 2B, Section E7.2.
[27] Exhibit 2B, Section E7.4.
[28] Exhibit 2B, Section E8.2.

defer the Enterprise Resource Planning ("ERP") system upgrade. Toronto Hydro made this decision when it learned that the system vendor, SAP, extended maintenance support for the existing ERP platform until 2027, and extended support until 2030.[29]

The Control Operations Reinforcement Program included in the 2020-2024 Plan is expected to be complete before 2025-2029 on time and within budget.[30]

E4.1.5 2020-2024 Variances: Other Capital

Expenditures in the "Other Capital" investment category are projected to be 69 percent higher than forecast over the 2020-2024 rate period. The primary driver for this increase is a result of a strategic decisions to increase pre-capitalized inventory to mitigate plan execution risks driven by supply chain disruptions (i.e. extended lead times and delivery uncertainty) experienced during the COVID-19 pandemic. This decision enabled Toronto Hydro to ensure equipment availability for its growing capital program, including critical compliance investments in at-risk PCB transformer replacements.[31]

E4.1.6 2020-2024 Variances: System O&M

System Operations and Maintenance ("System O&M") expenditures are driven by the need to maintain distribution assets and support the execution of Toronto Hydro's capital, maintenance, system response, and customer-driven work activities. The expenditures include the following activities:

- Preventative and Predictive Maintenance Programs (Exhibit 4, Tab 2, Schedule 1-3);
- Corrective Maintenance (Exhibit 4, Tab 2, Schedule 4)
- Emergency Response (Exhibit 4, Tab 2, Schedule 5);
- Disaster Preparedness Management (Exhibit 4, Tab 2, Schedule 6);
- Control Centre Operations (Exhibit 4, Tab 2, Schedule 7);
- Customer Operations (Exhibit 4, Tab 2, Schedule 8);
- Asset and Program Management (Exhibit 4, Tab 2, Schedule 9);
- Work Program Execution (Exhibit 4, Tab 2, Schedule 10); and

[29] Exhibit 2B, Section E8.4.
[30] EB-2018-0165, Exhibit 2B, Section E8.1.
[31] Please refer to Exhibit 4, Tab 2, Schedule 13 for further details on supply chain challenges

- Supply Chain (Exhibit 4, Tab 2, Schedule 13);

System O&M expenditures are forecast to increase from approximately $117.1 million in 2020 to $135 million in 2024, representing an average annual increase of 4 percent over the period. The primary drivers are asset and system maintenance needs, compliance obligations and resource requirements to support a higher volume and greater complexity of work in Toronto Hydro's service territory as the city of Toronto continues to grow, digitize, and decarbonize its economy. Below is a more detailed list of specific drivers:

- Corrective maintenance to address safety, reliability and environmental risks arising from a higher number of deficiencies identified through inspection programs.
- Compliance with incremental requirements imposed by the Electrical Safety Authority with respect to grounded-wye customer supply points and grounding of unused primary lines.
- The introduction of a Cable Diagnostic Testing program to support a more targeted approach for managing short-term cable systems risks.
- An increase to the Vegetation Management program to mitigate the reliability impacts of Toronto's expanding tree canopy.
- Increased overhead switch maintenance volumes and costs to ensure optimal maintenance cycles and keep pace with a growing population of assets.
- Greater requirements for testing, resealing, and reusing meters.
- The introduction of incremental Storm Guying inspections and corrective action to improve resiliency of poles during high wind events.
- The introduction of inspections for communication infrastructure at DER sites.
- Workforce requirements to support higher volumes and complexity of work, prepare the grid for energy transition and build capabilities required to support grid modernization objectives, including improvements to data quality and additional analytical capacity.
- An increase due to external factors such as weather in Emergency Response and customer demand for services such as vault access, locates and connections in Customer Operations.

The volume of maintenance for an asset class is dictated by asset class maintenance cycles and can vary from year-to-year. Similarly, the extent of maintenance required for inspected assets can vary from year-to-year depending on observed condition and other factors. To manage natural variances and volatility in maintenance programs, Toronto Hydro paces the execution of its maintenance plans where feasible and appropriate. For example, an increase in station battery failure for a particular year may be offset by a deferral of checker plate replacements at submersible vault locations or vault cleaning activities in Network Vaults.

E4.1.6.1 Capital Investment and System O&M

While capital investments can impact System O&M costs in different ways as discussed below, identifying specific impacts for each year is not practical due to the numerous factors involved and the gradual and ongoing nature of many of these impacts. Instead, the following summarizes and provides examples of the various ways System O&M costs are impacted by capital investments.

As discussed in more detail in Section D3.1.1.3, a significant portion of maintenance program costs are for activities which are independent of capital investments, such as cyclical inspections to meet minimum requirements under the Distribution System Code, and, where there is an impact of capital investments, the directional relationship depends on a number of factors, including the type of capital investment. For example, Growth investments are generally expected to put upward pressure on maintenance requirements as the number of assets on the distribution system increases. In addition, Toronto Hydro may introduce new assets, which require the introduction (and over time expansion) of new maintenance and inspection activities. For example, in 2022 Toronto Hydro began annual inspections, testing, and cleaning of its Bulwer Battery Energy Storage System ("BESS") assets under the Preventative and Predictive Station Maintenance program and expects to expand this to additional Toronto Hydro-owned energy storage systems as they are added under the Non-Wires Solutions capital program.[32,33] While Modernization investments can similarly increase maintenance costs by installing new assets such as SCADA-mate switches, it can also help to reduce some O&M costs. For example, the NCMC program installs sensors in network vaults providing remote monitoring and control, and through this Toronto Hydro expects to reduce the number of planned vault inspections required for each network vault per year, reducing maintenance costs by approximately $275,000 each year in the Preventative and Predictive Underground Line Maintenance program once all vaults are commissioned.[34] While this benefit of the NCMC program

[32] Exhibit 4, Tab 2, Schedule 3.
[33] *Supra* note 26.
[34] Exhibit 4, Tab 2, Schedule 2.

is not expected to be realized until 2027, the utility has already avoided costs by reducing the need for crews to visit vaults during outage events or to identify and investigate deficiencies.[35]

For Sustainment investments, typical like-for-like asset replacement is generally expected to have minimal to no impact on maintenance spending. If replacements are done at a high enough pace to materially improve asset health demographics (which is generally not the goal), this could in turn reduce the expected volume of deficiencies requiring corrective intervention (e.g. repair). However, this is complicated by the fact that a younger and healthier asset base may require relatively higher levels of Corrective Maintenance for subsets of assets due to the fact that younger equipment with defects may be better suited to repair (i.e. maintenance) as opposed to full replacement (i.e. reactive capital). Toronto Hydro does anticipate that Sustainment programs targeting legacy assets such as air-blast circuit breakers and the 4.16 kV system (including box construction and rear lot) will contribute to a gradual and modest reduction in costs related to legacy equipment maintenance as the population declines and the assets are replaced with equipment that typically requires lower maintenance costs (including emergency or corrective maintenance) or is maintenance free. For example, air-blast circuit breakers rely on air compressors, which Toronto Hydro inspects and maintains twice a year. As Toronto Hydro removes air-blast circuit breakers from the system through its Stations Renewal program, it will reduce and eventually eliminate the volume of these inspections under the Preventative and Predictive Station Maintenance program.[36]

As discussed in more detail in Section E4.2.6 below, growth in the overall size of the capital investment program is expected to increase costs in O&M programs that support such investments, including Asset and Program Management,[37] and Supply Chain.[38]

E4.1.7 2020-2024 Construction Work in Progress ("CWIP")

Table 3 below provides the 2020-2024 CWIP. Detailed explanations for capital expenditures are provided above and explanations for trends in In-Service additions are provided in Exhibit 2A, Tab 1, Schedule 1.

[35] For example, as of June 2023 Toronto Hydro had saved approximately $120,000 by not deploying crews during outage events. See Exhibit 2B, Section E7.3 for more details on the NCMC program and its benefits.
[36] Exhibit 2B, Section E6.6 and Exhibit 4, Tab 2, Schedule 3.
[37] Exhibit 4, Tab 2, Schedule 9.
[38] Exhibit 4, Tab 2, Schedule 13.

Table 3: Historical (2020-2022) and Bridge (2023-2024) CWIP ($ Millions)

	Actual			Bridge	
	2020	2021	2022	2023	2024
Opening CWIP	381.2	380.6	427.8	471.2	442.4
Additions (CAPEX)	447.4	532.4	597.8	579.1	620.3
Deductions (In Service Additions)	(447.9)	(485.2)	(554.4)	(607.9)	(606.3)
Closing CWIP	380.6	427.8	471.2	442.4	456.4

Note: Variances due to rounding may exist

E4.2 Forecast (2025-2029) vs. Historical (2020-2024) Expenditures

Table 4 below shows the contribution to the total capital program of each investment category for the current and future rate period. Compared to the current 2020-2024 rate period, there is a shift in the 2025-2029 rate period towards System Access and System Service investments to:

- keep pace with the demands of customers in a city that is growing, digitizing and decarbonizing its economy, and
- prepare the grid for the energy transition that is set to unfold over the next two decades by modernizing the utility's infrastructure and operations to improve resiliency, enable DER integration and deliver long-term reliability and efficiency benefits to customers.

Table 4: Historical and Forecast Share of Total by Investment Category

Category	Historical Share of Total (%)						Forecast Share of Total (%)					
	2020	2021	2022	2023	2024	Avg.	2025	2026	2027	2028	2029	Avg.
System Access	18%	26%	21%	22%	25%	**22%**	31%	31%	27%	23%	23%	**27%**
System Renewal	58%	46%	46%	54%	58%	**53%**	49%	48%	47%	50%	53%	**49%**
System Service	7%	13%	11%	6%	4%	**8%**	6%	5%	10%	12%	11%	**9%**
General Plant	13%	14%	19%	17%	13%	**15%**	14%	16%	15%	14%	12%	**14%**
Other CAPEX	4%	1%	2%	2%	1%	**2%**	1%	1%	1%	1%	1%	**1%**
Total	100%	100%	100%	100%	100%	**100%**	100%	100%	100%	100%	100%	**100%**

In the sections that follow, Toronto Hydro provides a summary of key programs and investment priorities that are driving the planned increases in each of these categories in 2025-2029 compared to 2020-2024. Additional details about each of these programs and priorities are found throughout other section of this Distribution System Plan.

E4.2.1 System Access: Historical vs. Forecast Expenditures

Table 5: System Access: 2020-2029 Expenditures ($ Millions)

	Actual			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

Toronto Hydro expects System Access expenditures to continue to increase into the 2025-2029 rate period. As discussed in Section E2.2, this overall increase is driven by two primary considerations:

- continued growth and development in the city of Toronto, including the expected impacts of electrification as more customers turn to electricity for their day to day needs such as transportation and building heating systems;
- necessary replacement of end-of-life revenue meters which will also offer Toronto Hydro the opportunity to modernize this critical part of the system with Advanced Metering Infrastructure (AMI) 2.0.

As discussed in Section D2, the City of Toronto leads North America in new buildings under construction. Toronto Hydro expects continued growth in customer load and generation connections, as well as major infrastructure projects (e.g. transit development) that are externally initiated. Toronto Hydro is also due to renew its sizable population of end-of-life residential and small commercial and industrial (C&I) revenue meters.[39] Inflation for materials, labour and other construction-related costs is also driving increases in certain programs. For more information on the programs in this category, refer to Section E5.

[39] *Supra* note 9.

E4.2.2 System Renewal: Historical vs. Forecast Expenditures

Table 6: System Renewal Expenditures: 2020-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Renewal	261.5	247.3	276.5	314.0	358.8	359.7	366.5	391.3	423.7	429.1

Over the 2025-2029 rate period, Toronto Hydro plans to increase its System Renewal investments in the 2025-2029 rate period by approximately 35 percent compared to 2020-2024 rate period. As discussed in Section E2.2, this increase is necessary to manage significant safety, reliability, and environmental asset risks, maintain the system in a state of good repair by managing the overall health demographics of assets, and ensure stable and predictable grid performance for current and future customers.

As mentioned in Section E4.1.2 above, Toronto Hydro constrained investment in key System Renewal programs to manage funding pressures in the 2020-2024 rate period. This prudent decision, along with other factors, led to increasing investment needs in the 2025-2029 rate period including:[40]

- asset condition demographics (e.g. wood pole condition);
- persistent backlogs of high-risk legacy assets such as direct-buried cable;
- growing asset stewardship risks in the downtown core, including those related to aging lead cable and deteriorating civil assets;
- growing backlog of critical stations-level equipment at risk of failure;
- increasing performance pressures on the system from climate change, necessitating greater investment in resiliency;
- elimination of PCB at-risk assets from the distribution system;
- the increasingly urgent need to convert aging, legacy 4 kV / 13.8 kV parts of the system to higher voltage standards that are capable of handling electrified loads, DERs and automation;
- the need to accelerate replacement of obsolete mechanical stations relays with digital relays capable of supporting advanced operational functions and grid automation; and

[40] See Sections D1, E2, and Section E6 for additional details.

- anticipated cost pressures from construction inflation in the City of Toronto which reached a 40-year all time high in the 2020-2024 rate period.

Toronto Hydro expects to eliminate PCB at-risk units from the distribution system by 2025 and box-framed poles by 2026. The winddown of these investment priorities will enable the utility to ramp-up investment in the conversion of legacy 4 kV / 13.8 kV parts of the system. In addition to addressing the reliability risks posed by these aging assets, the conversion of these configurations to higher voltage standard enables the utility to accommodate higher volumes of electrified loads.

E4.2.3 System Service: Historical vs. Forecast Expenditures

Table 7: System Service Expenditures: 2020-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Service	32.8	68.4	67.2	32.8	24.3	38.3	35.3	83.0	95.1	101.2

Over the 2025-2029 rate period, Toronto Hydro plans to increase its System Service investments by approximately 56 percent compared to 2020-2024 investment levels. Expenditures in this category are central to Toronto Hydro's strategy to expand and modernize its grid and operational capabilities to address key drivers of change within its business, including electrification, DER proliferation, and climate change impacts. For more information about this strategy see Section D4 – Capacity Planning and Electrification Strategy and D5 – Grid Modernization Strategy.

Increased investments in this category are largely driven by:

- capacity expansion needs in the Stations Expansion program including investment in a new Transformer Station to support expected load growth in the Downsview areas and Hydro One contribution to expand capacity at existing stations, such as Scarborough TS.[41]
- a paced ramp-up in the System Enhancement program to enhance system observability and controllability, and enable the utility to be ready for widescale grid automation in the horseshoe areas of its system in the next decade.[42] These investments are expected to deliver long-term reliability and efficiency benefits to customers.

[41] *Supra* note 27.
[42] *Supra* note 12.

- investments in Energy Storage systems (ESS) to improve the grid's capacity to connect and integrate Renewable Energy Generation (REG) connections which are expected to play an increasing role in advancing customers' and stakeholders decarbonization objectives.

E4.2.4 General Plant: Historical vs. Forecast Expenditures

Table 8: General Plant Expenditures: 2025-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
General Plant	56.1	72.4	112.9	96.5	80.7	103.9	119.1	124.9	116.1	98.6

Over the 2025-2029 rate period, Toronto Hydro plans to increase its General Plant investments by approximately 34 percent compared to 2020-2024. Expenditures in this category are driven by asset lifecycle management for fleet, facilities, and IT equipment that support the efficient execution and management of Toronto Hydro's capital and operational work programs. In addition, Toronto Hydro plans to continue to invest in paced decarbonization of its facilities and fleet emissions, as well as in the relocation of an enterprise data centre. The latter project is required to enable the utility to expand and reliably operate this critical piece of infrastructure in accordance with the growth of the distribution system, as the significant challenges associated with the data centre's current location preclude such expansion and pose significant business continuity and reliability risks.

This category is also driven by investments in cyber security and enterprise technology software solutions, which are needed to achieve the following outcomes:

- strengthen protection and resilience against increasing digital threats brought on by advancements in technology and changes in geopolitical dynamics;
- support grid modernization efforts detailed in Section D5;
- drive continuous improvement in productivity through process automation;
- leverage technology tools and capabilities to serve customers in a timely and effective manner and deliver good experience as more customers turn to electricity for their day-to day energy need; and
- implement public policy initiatives and maintain compliance with legislative and regulatory requirements.

E4.2.5 Other Capital: Historical vs. Forecast Expenditures

Table 9: Other Capital Expenditures: 2025-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Other Capital	17.4	4.6	12.8	12.6	7.7	6.3	7.0	8.7	10.3	12.0

Other Capital includes forecasted amounts for Allowance for Funds Used during Construction ("AFUDC") which are required during the execution of capital programs in the 2025-2029 rate period.[43]

E4.2.6 System O&M: Historical vs. Forecast Expenditures

Table 10: System O&M Expenditures: 2020-2029($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System O&M	117.1	117.5	124.1	127.1	135.0	144.1	148.9	153.0	159.0	164.5

System O&M expenditures are expected to increase at an average annual rate of approximately 3 percent between 2025 and 2029. The increases are driven by a number of factors:

- Toronto Hydro is expanding inspection and maintenance activities in key areas through the Preventative and Predictive maintenance programs, resulting in an 11 percent increase between 2024 and 2025, followed by a moderate 1 percent average annual increase from 2026-2029. Starting in 2025 Toronto Hydro is adjusting inspection cycles for wood poles from ten years to eight years to manage failure risk driven by wood pole age and condition demographics. Toronto Hydro will also begin inspecting concrete and steel poles as part of its Pole inspection program on a ten-year cycle. Toronto Hydro will transition to a minimum six-year maintenance cycle for overhead switches, which represents an increase from the current variable cycle, which is generally greater than six years. Toronto Hydro will continue to ramp up the Cable Diagnostic testing segment in Preventative and Predictive Underground Line Maintenance program, collecting key condition information on a greater

[43] As discussed in Section E4.1.5, Road Cut Restoration costs and Major Tools are attributed directly to capital program expenditures and are not included in Table 7.

number of feeders to inform both short- and long-term investment decisions. The introduction of incremental inspection activities at DER sites and increasing volume of Energy Storage locations within the Preventative and Predictive Stations program also drive cost increases. Toronto Hydro plans to reduce its Network Vault civil inspection program starting in 2027 as a result of the implementation of Network Condition Monitoring and Control resulting in reduced costs in that program. The large majority of Toronto Hydro's inspection and maintenance programs are cyclical in nature, with cycles established to meet regulatory requirements, as discussed in Exhibit 2B, Section D3. As a result, significant reductions to inspection or maintenance programs are not expected in the 2025-2029 period. Differing volumes of work and inflationary impacts will result in year over year fluctuations in expenditures between 2025-2029 within these programs;[44]

- The Corrective Maintenance program expenditures increase by 14 percent between 2024 and 2025, followed by a 3 percent average annual increase from 2026-2029. The increase in the Corrective Maintenance Program is driven by the need to address a growing backlog of P3 deficiencies within the system. Expected expenditures related to increasing spot tree trimming and corrective work for DER sites also drive an increase in this program. For more details, please see Exhibit 4, Tab 2, Schedule 4;
- A 12 percent increase between 2024 and 2025 is forecasted within the Emergency Response program. Inflationary pressures including increased labour and vehicle costs for services and a new contract for external resources that will be effective in 2025 contribute to the increase. From 2026-2029, expenditures align to a 2 percent average annual increase;[45]
- The Supply Chain program is growing by 14 percent between 2024 and 2025 followed by an average annual increase of 6 percent between 2026-2029. The increase in costs is primarily due to higher payroll and contract costs required to support an expanded Capital Program within a more complex global supply chain environment;[46]
- The Asset and Program Management program will have an average annual increase of 6 percent over the 2025-2029 rate period driven primarily by higher payroll and external contract costs to support an expanding capital and maintenance program and the expansion of the Grid Modernization function. This function will allow the utility to forecast, understand, and manage a more complex system as it becomes increasingly decarbonized,

[44] Exhibit 4, Tab 2, Schedules 1-3.
[45] Exhibit 4, Tab 2, Schedule 5.
[46] *Supra* note 38.

decentralized, and digitized. Incremental resources, new skillsets, and third-party support is required within the planning and engineering functions in support of the above needs;[47]

- The Work Execution program will have an average annual increase of 5 percent over the 2025-2029 rate period. The growth in this program is driven directly by the need for additional headcount to support a growing capital and maintenance program with increasing complexity to support the energy transition. The increase in headcount in key Certified and Skilled Trades and Designated & Technical Professional positions is required to enable internal work execution, whereas key resources such as field, project, and contract managers are required to support external work execution. Increases in training costs, tools and safety equipment, and personal protective equipment ("PPE") are also required;
- In addition, increasing resource and skill requirements and capabilities to support grid modernization results in higher costs across various business functions. For example, increasing the workforce of Control Centre Operations will be crucial as Toronto Hydro expands its grid and modernizes system operation through more sophisticated data analysis and automation, which will require more staff both to handle increasing volumes of work and deploy specialized skills and knowledge made necessary by the evolution of operational systems; and
- Inflationary pressures are also a key contributor to increasing expenditures over the forecast period across the various System O&M programs.

[47] *Supra* note 37.

E4.2.7 Forecast Construction Work in Progress ("CWIP")

Table 11 below provide the 2025-2029 CWIP. Detailed explanations for capital expenditures are provided above and explanations for variances in In-Service additions are provided in Exhibit 2A, Tab 1, Schedule 1.

Table 11: Forecasted 2025-2029 CWIP ($ Millions)

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Opening CWIP	456.4	536.3	595.1	622.7	681.7
Additions (CAPEX)	725.8	758.1	823.2	828.2	812.3
Deductions (In Service Additions)	(645.9)	(699.4)	(795.6)	(769.2)	(875.4)
Closing CWIP	536.3	595.1	622.7	681.7	618.6

Note: Variances due to rounding may exist

E5.1 Customer Connections

E5.1.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 356.2	**2025-2029 Cost ($M):** 476.5
Segments: Load Connections; Generation Connections	
Trigger Driver: Customer Service Requests	
Outcomes: Customer Focus, Public Policy Responsiveness, Operational Effectiveness - Safety, Operational Effectiveness - Reliability	

The Customer Connections program ("the Program") captures system investments that Toronto Hydro is required to make to provide customers with access to its distribution system. This includes enabling new or modified load connections and distributed energy resources ("DER") connections to the distribution system, in accordance with legal and regulatory obligations under various statutes and codes. This Program is a continuation of customer connection activities described in Toronto Hydro's 2020-2024 Distribution System Plan.[1]

Toronto Hydro's primary objective in this Program is to provide new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system. In pursuing this objective, the utility strives to meet, and where possible, exceed, all mandated service obligations. In 2022, Toronto Hydro completed 99.9 percent of low voltage (below 750 V) and 99.1 percent high voltage (750 V or above) connections on time, a performance improvement from 2018 of 1.6 percent for low voltage connections and 0.8 percent for high voltage connections. In 2022, 92.4 percent of DER connections were connected on time.[2]

The Program is comprised of two segments:

- **Load Connections**: This segment involves completing new load connections and upgrades to existing load connections. Customers are connected to one of the various overhead or underground distribution systems in the City. The work also includes any expansion work necessary to address capacity constraints for the purpose of connecting customers; and

[1] EB-2018-0165, Exhibit 2B, Section E5.1
[2] These metrics are published in Toronto Hydro's 2022 Scorecard; See: https://www.oeb.ca/utility-performance-and-monitoring/scorecard/600/view

- **Generation Connections**: This segment involves connecting DER customers to the distribution system.

The investments made by Toronto Hydro in this Program support the ongoing economic growth and development in the City of Toronto.[3] The connection of DER facilities under this Program supports the achievement of the public objectives with respect to facilitating innovation and supporting DER integration within Ontario's electricity system and the Ministerial directive issued by the Minister of Energy on October 21, 2022.

E5.1.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro customer focus objectives by: ○ Fulfilling customer service requests as mandated by Sections 6.2.4 (generation connections) and 7.2 (customer connections) of the Distribution System Code ("DSC"), Electricity Act, 1998 (Electricity Act), and Ontario Energy Board Act, 1998 (OEB Act); and Toronto Hydro's Conditions of Service and Electricity Distribution License; ○ Completing low and high voltage connections within five and ten business days respectively at least 90 percent of the time, as measured pursuant to the OEB's connection metrics and section 7.2 of the DSC; ○ Completing customer appointments in accordance with the OEB's Appointment Scheduling and Appointments Met metrics, 90 percent of the time, as per sections 7.3 and 7.4 of the DSC; and ○ Responding to inquiries requiring a written response within ten business days at least 80 percent of the time, as measured pursuant to the OEB's Written Response metric and section 7.8 of the DSC. ○ Connecting DER facilities to the distribution system as mandated by sections 25.36, and section 26 of the Electricity Act, 1998; and; without extensive delays or adverse impacts to existing customers, within 5 business days at least 90 percent of the time on a yearly basis as per section 6.2.7 of the DSC.

[3] City of Toronto, Toronto Official Plan, "online", https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/official-plan/ ; City of Toronto, City Planning Development Pipeline 2021, "online", https://www.toronto.ca/wp-content/uploads/2021/06/963e-Development-Pipeline-2021.pdf; Waterfront Toronto, Integrated Annual Report 2021-2022, June 23, 2022, "online", https://www.waterfrontoronto.ca/sites/default/files/202207/Waterfront%20Toronto%20Integrated%20Annual%20Report%202021-2022.pdf

Public Policy Responsiveness	• Supports the Ministerial directive to facilitate innovation and support DER integration within Ontario's electricity system
Operational Effectiveness - Safety	• Contributes to compliance with Electrical Distribution Safety (O. Reg 22/04) and safety objectives by: ○ Ensuring service connections are compliant with applicable requirements; and ○ Ensuring Electrical Safety Authority connection permits are available prior to connecting new or upgraded customers' service entrance equipment.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, System Capacity) by installing assets that meet up-to-date standards and provide sufficient capacity when completing the connection request.

E5.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Customer Service Requests
Secondary Driver(s)	Mandated Service Obligations

E5.1.3.1 Load Connections

The Load Connections segment is driven by customer requests to connect to Toronto Hydro's distribution system and service upgrades for existing customers. Toronto Hydro has seen an increase in the volume and complexity of customer connections due to ongoing growth and development in the city, larger connections (e.g. for data centres, transit etc.) and the energy transition. Densification and growth in the City of Toronto, including increased residential and commercial developments as well as mass transit system growth, are fundamental drivers for the increased volume of work in the Load Connections segment, as many, if not all, new developments will require new or modified connections to Toronto Hydro's distribution system. The energy transition is also an important driver of the Load Connections segment as customers look to the electricity grid to meet more of their energy needs. Toronto Hydro anticipates that the number of customer service requests and the size of the requested connections will continue to trend up to accommodate growing residential and commercial needs. Toronto Hydro has a legal obligation, pursuant to section 28 of the *Electricity Act*, to fulfill these service connection requests or to make an offer to connect ("OTC") for any customers in its service area.[4]

Toronto continues be one of the fastest growing cities in North America. Serving this growing city, Toronto Hydro receives a high volume of requests for connections and upgrades for residential and commercial developments each year. Toronto currently has 238 construction cranes operating, 4.7 times as many as the next most active city, Seattle.[5] From 2017 to 2022, the city's development pipeline included 2,413 projects in various stages of approval and completion as shown in Figure 1 below.[6] Toronto Hydro anticipates that a large number of projects and proposed loads submitted between 2017 and 2022 are expected to be completed within the 2025-2029 period or shortly thereafter based on the average completion rate and the number of units proposed for the City of Toronto.[7] Thus, Toronto Hydro expects that the current rate of development will continue over the 2025-2029 period. These projects in the development pipeline represent a City record of 717,327 residential units and 14,484,961 square metres of non-residential gross floor area, the highest development volumes for any five-year period the City has reported on to date. The pace of development in Toronto could increase even further with the recent passage of the *More Homes Built Faster Act, 2022*[8] by the Government of Ontario. This act is intended to expedite the approval of development projects and provide new tax incentives and funding mechanisms aimed at encouraging development. Toronto Hydro will continue to monitor the impact of this legislation on the distribution system.

[4] Subject to certain exemptions as set out in the Distribution System Code, including Section 3.1.1 of the Distribution System Code ("DSC")
[5] Rider Levett Bucknall (RLB), Crane Index® for North America, Q1 2023, "online", https://www.rlb.com/americas/insight/rlb-crane-index-north-america-q1-2023/
[6] Including projects that are pending approval, approved, awaiting or holding building permits, or under construction - The 2413 pipeline projects breakdown is 622 built, 879 active and 912 under review: Toronto City Planning, Profile TO, Development Pipeline 2022 Q2, "online", https://www.toronto.ca/wp-content/uploads/2023/02/92b5-CityPlanning-Development-Pipeline-2022-Q2.pdf
[7] Discussed further in the Load Demand program, see Exhibit 2B, Schedule E5.3.
[8] Bill 23, More Homes Built Faster Act, 1st Sess, 43rd Parl, 2022, https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-23

	Built	Active	Under Review	Total in Pipeline	% of Total	% of Growth Areas
City of Toronto	**622**	**879**	**912**	**2,413**	**100.0%**	
Growth Areas	**394**	**549**	**605**	**1,548**	**64.1%**	**100.0%**
Downtown and Central Waterfront	142	205	179	**526**	21.7%	31.5%
Centres	30	48	47	**125**	5.2%	14.5%
Avenues	149	209	279	**637**	26.4%	28.3%
Other Mixed Use Areas	73	87	100	**260**	10.8%	25.6%
All Other Areas	228	330	307	**865**	**35.9%**	

Source: City of Toronto, City Planning: Land Use Information System II

Development projects with activity between January 1, 2017 and June 30, 2022. Built projects are those which became ready for occupancy and/or were completed. Active projects are those which have been approved, for which Building Permits have been applied or have been issued, and/or those which are under construction. Projects under review are those which have not yet been approved or refused and those which are under appeal.

Figure 1: Proposed Projects in the City of Toronto (2017-2022)

In addition to volume of projects, Toronto Hydro also anticipates that there will be a greater need for larger and more complex connections. There has a been a substantial increase in larger commercial and multi-use projects requiring greater than 10MVA of demand load per project, and data centres requiring larger loads than previously required from Toronto Hydro. In addition, the city is experiencing a period of unprecedented expansion of electrified public transportation requiring large new load connections to Toronto Hydro's distribution system (e.g. Yonge North Subway Extension, Scarborough Subway Extension, Eglinton Crosstown West Extension, Ontario Line).[9]

Furthermore, the City is experiencing a shift to clean energy, and electrification through the adoption of emerging technologies such as electric vehicle charging, electric heat pumps, and water heaters. As the adoption and demand of such technologies continues to evolve and grow, the demand for access to Toronto Hydro distribution system must be leveraged to support these demands. Immediate growth areas being supported by Toronto Hydro's distribution system include electric vehicle charging for: public streets, City fleet vehicles (including TTC), Toronto Parking Authority parking lots, residential homes, commercial and residential developments. Ongoing and other evolving areas include heating/cooling systems (heat pumps), and complete home electrification at single-family residential home and residential complex levels.

[9] Further details can be found in Exhibit 2B, Schedule E5.2

This pace of development and growth is consistent with the City's projected growth in population, which is over 2.97 million as of July 2021 and is expected to continue to increase into the future.[10] Since the City of Toronto is bounded, accommodations for population growth and needed support systems (residential, retail, commercial, multi-use, institutional, transit developments), including access to Toronto Hydro's distribution system to support population growth, will intensify as the population increases.

As illustrated in Figure 2, from 2012 to 2022, Toronto Hydro connected approximately 76,000 customers, representing a 11 percent increase in its customer base (average of 1.0 percent per year), and approximately 20,000 customers from 2018 to 2022, representing a 2.6 percent increase (average of 0.7 percent per year). Similar levels of growth are expected for the 2025-2029 period, as described in the Customer Forecast Section.[11] These additional customers were connected to Toronto Hydro's distribution system as a result of the investments in the Load Connection segment.

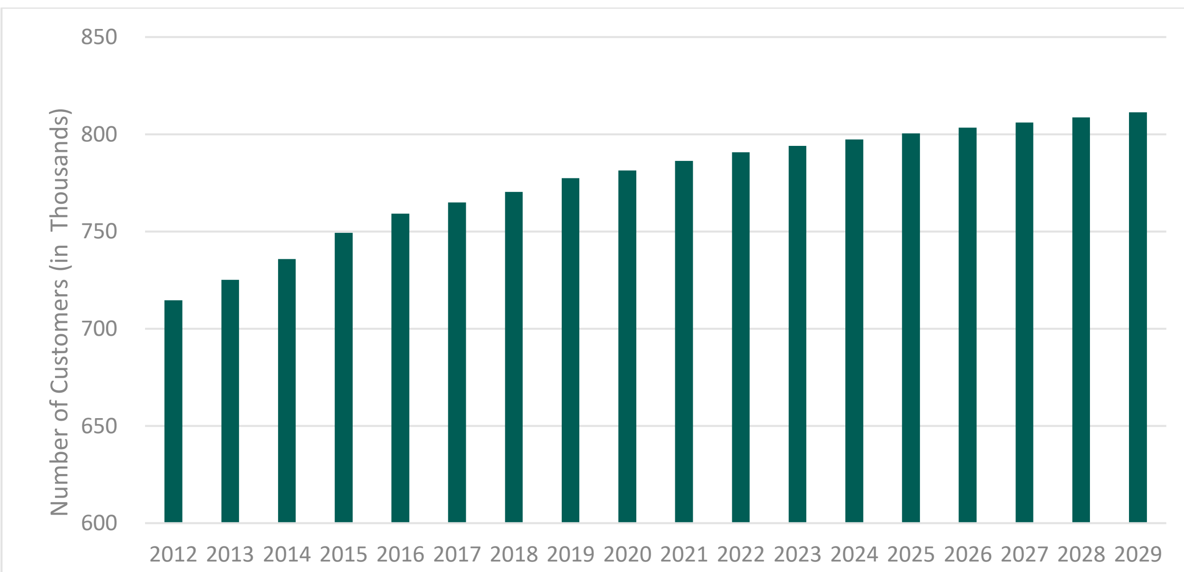

Figure 2: Historical and Forecast Number of Toronto Hydro Customers

10 Province of Ontario, Ontario Population Projections, "online", https://www.ontario.ca/page/ontario-population-projections#chart8;
The greatest growth is expected in the areas of: City of Toronto, 2021 Census, "online", https://www.toronto.ca/wp-content/uploads/2022/02/92e3-City-Planning-2021-Census-Backgrounder-Population-Dwellings-Backgrounder.pdf
For the period 2016 to 2021, the districts of Spadina-Fort York, Toronto Centre, Etobicoke-Lakeshore, and Toronto-St Paul's have shown the greatest growth in population at growth in populations of 17.9%, 15.5%, 9.8%, and 8.4% respectively

11 Exhibit 3, Tab 1, Schedule 1.

Customer connections can be in the form of a basic connection, or a connection requiring expansion work. Each new or upgraded service connection must meet the individual needs of the customer. This includes customer specific type, size, required demand load, geographical location of the customer's site, geographical availability of Toronto Hydro's distribution system in relation to the customer's site, and available distribution system infrastructure and capacity provisions.

The types of connections Toronto Hydro performs can generally be divided into two categories as follows:

- **Low voltage connections (below 750 Volts) ("LV"):** These connections primarily involve residential and small commercial customers (GS<50 rate class) supplied at 750 Volts or less whose average monthly maximum demand is less than, or is forecasted to be less than 50 kW. The number of connections remains high at over 2000 connections per year for the period of 2020-2022. This work is typically seasonal and has a relatively short turnaround time. As part of Toronto Hydro's obligations, the utility works with customers to provide options for a new connection or service upgrade. As per the DSC, section 7.2.1, these service requests must be completed within 5 business days from the day on which all applicable service conditions are satisfied. or at a later date as agreed to by the customer and distributor; and
- **High voltage connections (750 Volts and above) ("HV"):** These connections primarily relate to larger residential and commercial developments. These customers typically engage Toronto Hydro years before service is expected to be required. Figure 3 provides a year-over-year comparison of the volume of new formalized high voltage requests that Toronto Hydro receives on an annual basis. High voltage connections increased by 27.6 percent for the period 2020 to 2022. As per section 7.2.2 of the DSC, these service requests must be completed within ten business days from the day on which all applicable service conditions are satisfied, or at a later date as agreed to by the customer and distributor.

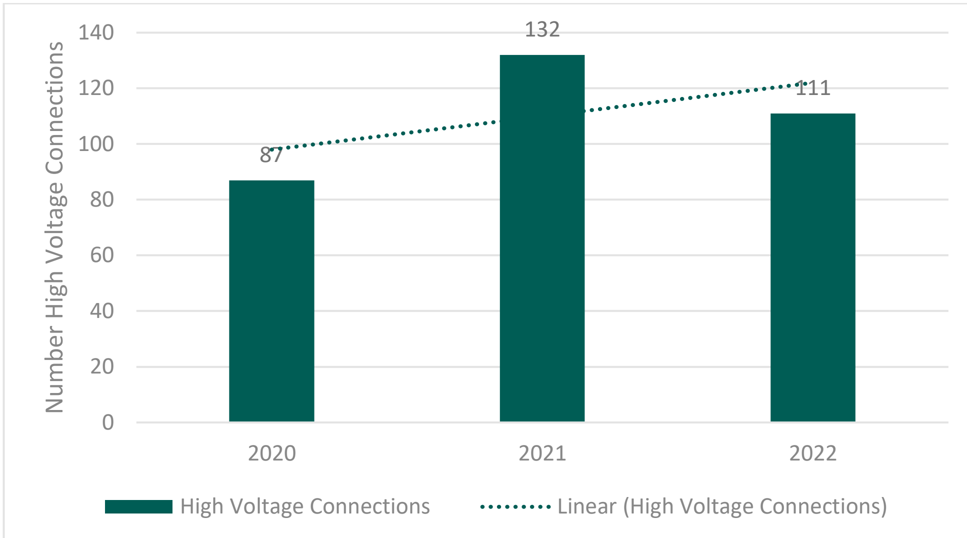

Figure 3: High Voltage Connections 2020-2022

For both low and high voltage service connections, applicable service quality requirement must be met at least 90 percent of the time on a yearly basis.

Toronto Hydro continues to process a high amount of feeder requests[12] at over 800 per year, and has experienced a 29.8 percent increase in feeder requests since 2020. In 2022, Toronto Hydro processed 1055 feeder requests, the highest volume to date. The overall increasing trend in the volume of requests processed from year to year is expected to continue up to and throughout the 2025-2029 period. Following a feeder request, the connection typically materializes within five years, from the day the feeder request was created, excluding any project delays. As a result, the number of feeder requests received between 2021 and 2022 are expected to drive work in the 2025-2029 period.

[12] **Feeder request**: An internal request to determine the appropriate point and method of connecting customers exceeding 50 kW to Toronto Hydro's distribution system. Feeder requests relate to both potential and proposed projects in their preliminary stages.

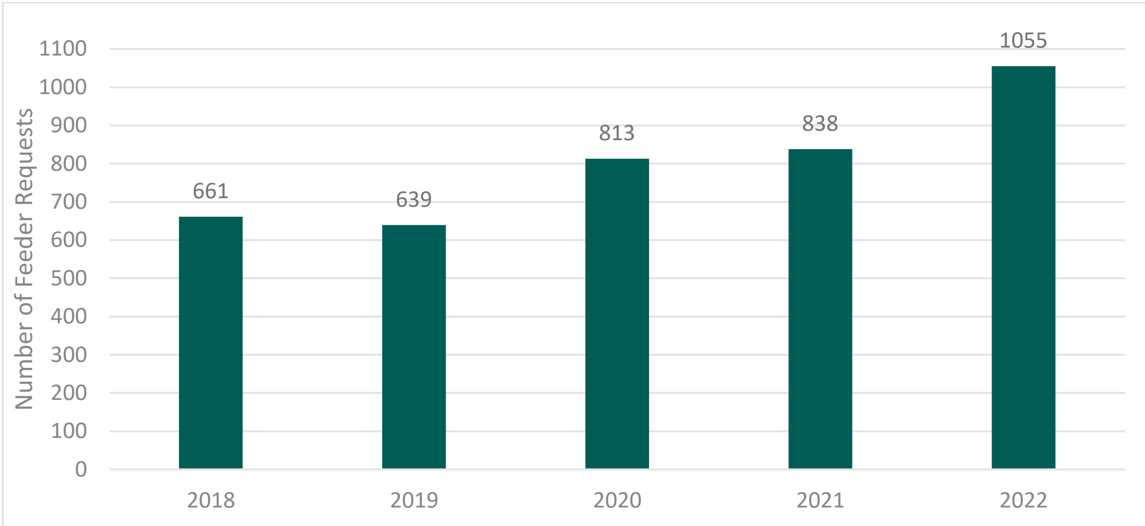

Figure 4: Feeder requests processed (2018-2022)

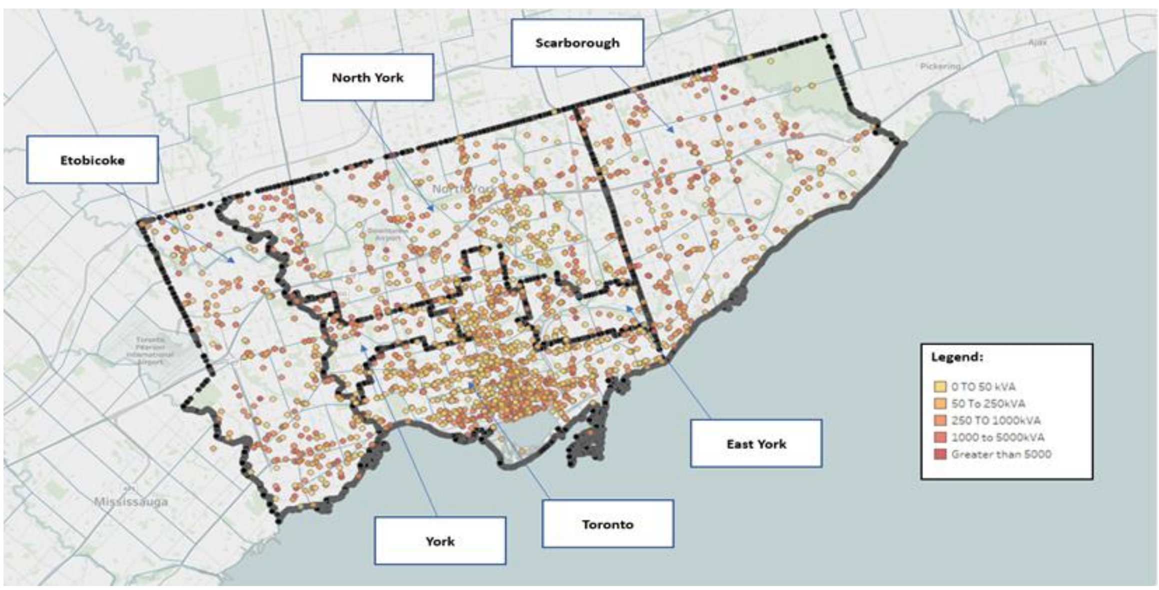

Figure 5: Load Additions in the City of Toronto during the 2018-2022 Period

Similar trends were observed in the overall increasing volumes of Offers to Connect (OTCs) issued requiring expansion work throughout the 2019 to 2022 period, as illustrated in Figure 6*.* The number of Offers to Connect (OTCs) between 2020-2022 has already exceeded 68 percent of the total volume count of OTCs for the five-year period 2015-2019. Expansion work is typically needed for larger connections or requests in areas of the City that are capacity constrained. This involves the installation or upgrade of distribution assets such as new circuits or civil infrastructure required to accommodate new customer loading. Such work can have a significant cost impact as it typically requires a substantial amount of resources to plan and construct the infrastructure necessary to connect a large customer. The resulting expansion projects are usually large-scale and complex, and thus require weeks or months to complete. Connecting customers to the distribution system without completing the necessary expansions can negatively impact system reliability and safety.

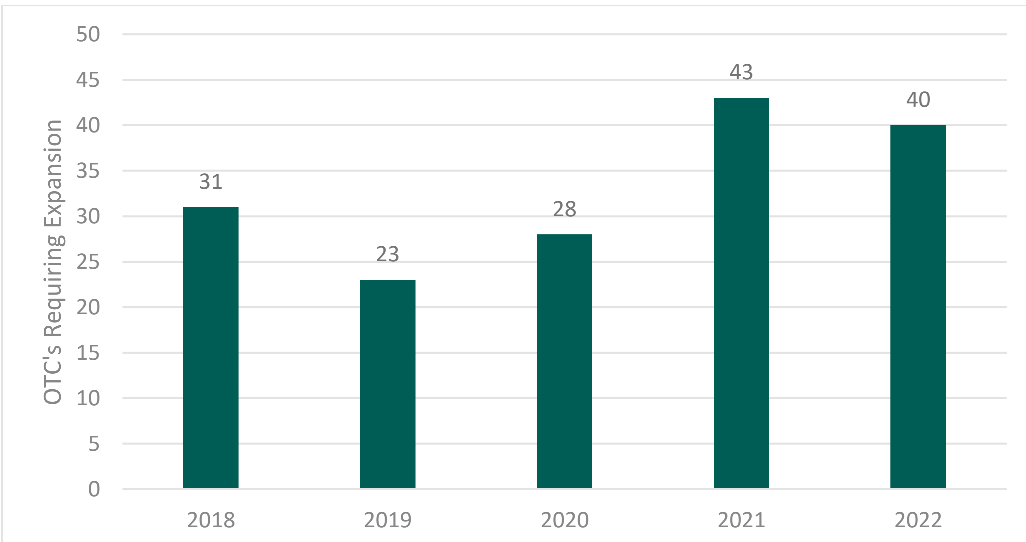

Figure 6: Offers to connect Requiring Expansion

E5.1.3.2 Generation Connections

As per section 25.36 of the *Electricity Act*, Toronto Hydro is mandated to connect renewable DER while maintaining the safety and reliability of the system for existing customers. Toronto Hydro is also obligated under section 6.1 of its Distribution License and section 26 of the *Electricity Act* to provide generators with non-discriminatory access to its distribution system and to provide access for renewable energy generation facilities. Under Section 6.2 of the DSC, for all types of DERs, Toronto Hydro has an obligation to enable and connect the DER. Toronto Hydro must balance its obligations to prospective and existing DER connections with its responsibilities to maintain a safe and reliable distribution system for its load customers. When connecting and assessing DER facilities, Toronto Hydro is also required to meet certain timelines:

- Based on OEB's recently released Distributed Energy Resources Connection Procedures (DERCP) document, the distributor must complete and provide a Connection Impact

Assessment (CIA) with cost estimates within 60 days[13] of receipt of substantially complete application for small and mid-sized DER where no system reinforcement or expansion work is required, and within 90 days where either the DER is large or system reinforcement or expansion work is required; and

- A distributor, as per sections 5.3.13 and 5.3.14 of the DERCP, shall connect an applicant's micro-embedded generation facility to its distribution system within 5 business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer and distributor 90 percent of the time on a yearly basis.

Toronto Hydro supports connecting DER to the distribution system in alignment with the DERCP and in coordination with Hydro One and the IESO. As of the end of 2022, Toronto Hydro connected 2,424 DER connections from customers and developers under a variety of technologies and applications with a total connected capacity of 304.94 MW. These can be broken down into three (3) different categories as shown in Table 4 below:

- **Renewable:** consists of DER based on renewable technologies, such as solar photovoltaic, wind turbine and bio-gas generators;
- **Energy storage:** refers to DER related to the capture of energy, such as batteries and underwater compressed air; and,
- **Non-renewable:** refers to conventional fossil-fuel based DER, such as natural gas generators and combined heat and power ("CHP").

1. Existing Generation Connections

An overview of the number and total capacity of DERs and their distribution across the city are provided in Table 4, Table 5 and Figure 7.

Table 4: Cumulative Existing Generation Connections by type

Type	2015	2016	2017	2018	2019	2020	2021	2022
Renewable	1296	1547	1749	2072	2094	2126	2185	2280
Energy Storage	1	4	4	10	11	22	24	28
Non-Renewable	35	38	44	54	60	87	112	116
Total	**1332**	**1589**	**1797**	**2136**	**2165**	**2235**	**2321**	**2424**

[13] Ontario Energy Board, Distributed Energy Resources (DER) Connections Review, "online", https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/distributed-energy-resources-der

Table 5: Cumulative Existing Generation Capacity (in MW) by type

Type	2015	2016	2017	2018	2019	2020	2021	2022
Renewable	71.9	86.6	96.6	108.7	110.0	111.3	114.1	116.2
Energy Storage	0.7	0.7	0.7	4.5	9.1	17.6	18.2	18.7
Non-Renewable	91.9	98.4	114.4	119.6	127.7	157.4	169.5	170.0
Total	**164.5**	**185.6**	**211.6**	**232.8**	**246.8**	**286.3**	**301.8**	**304.9**

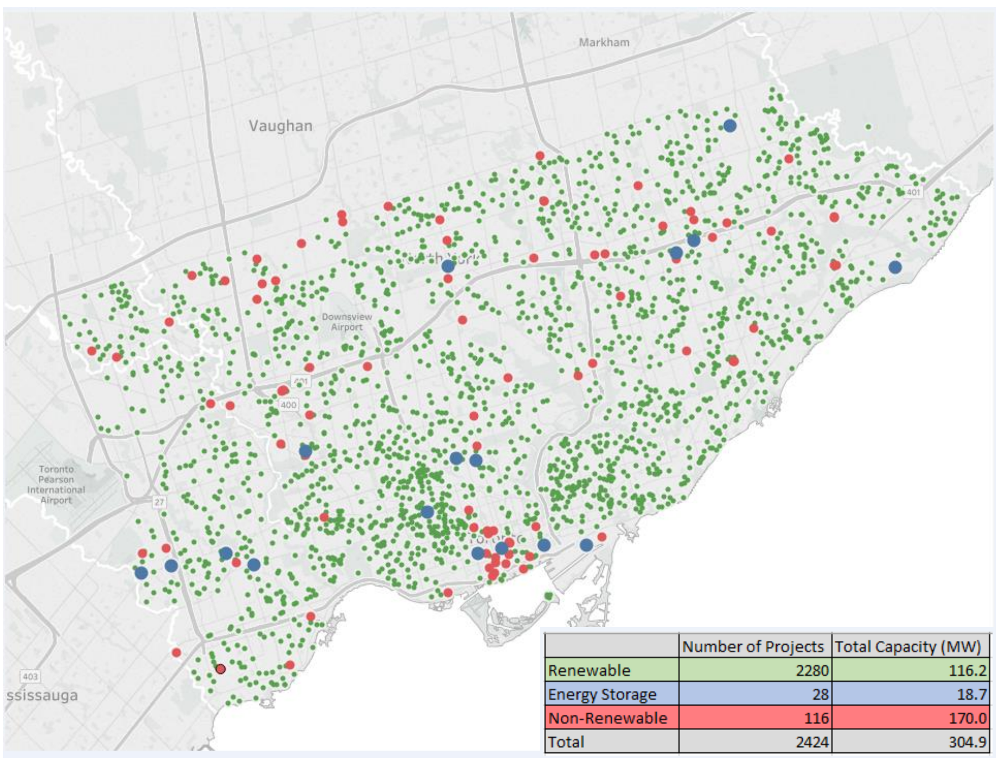

Figure 7: Generation Connections in Toronto Hydro Service Area by Generation Type

Interest in generation projects within Toronto Hydro's service territory saw a greater than anticipated decrease with a 71.9 percent decline in renewable pre-assessment applications in the years immediately following the conclusion of the FIT program in 2018. However, customers have continued to show an interest in DER projects, and connections continue to grow, albeit at a slower pace. Tables 4 and 5 show increases across all categories of DERs. As of the end of 2022, renewable installations represent the largest category of DER by number of connections while non-renewables represent the largest category by generation capacity. Non-renewable DERs are generally larger capacity connections used to support large commercial or industrial facilities. With recent regulatory and public pressures towards clean energy, it is possible that the combined installed capacity for renewable and energy storage based DER's could surpass non-renewable in this next rate period.

a. Renewable DER Connections

Since the FIT program ended in 2018, Net Metering has become the predominant program choice for connecting renewable generation. Net Metering financially compensates customers through bill credits for any excess electricity generated to the grid at the going rate for electricity. However, the financial benefit is generally less lucrative when compared with the FIT program. While interest in Net Metering continues to grow, pre-assessment and connection applications under this program are lower by comparison to the years when the FIT program was active. Still, since 2018, Net Metering pre-assessments had an average annual growth of 36 percent between 2018 and 2022. In 2022, a total of 362 pre-assessments were completed along with 95 connections, both record highs for this program in the midst of the COVID-19 pandemic.

b. Energy Storage Connections

There has been a relatively low number of energy storage connections in Toronto to date; with only 28 connected projects as of 2022. However, Toronto Hydro's current Energy Storage project pipeline anticipates the connection of an additional 12 projects worth 31.9 MW by the end of 2023. Some of these projects include large battery systems being installed at various Metrolinx and Toronto Transit Commission (TTC) stations used for light-rail transit and hybrid bus charging. The relatively large pipeline in 2023 can be partially attributed to the advancement of projects that had been delayed in earlier years as a result of the COVID-19 pandemic.

c. Non-Renewable DER Connections

In 2018, Toronto Hydro saw significant interest in non-renewable generation with pre-assessment applications increasing to 124 from 61 the previous year. In 2019 however, pre-assessment applications declined to only 35 for non-renewable DER and have continued to fall with only 5 requested in 2021. A similar trend can be observed with CIA applications reducing from 25 to 4 between 2020 and 2021. The timing of this decrease coincides with changes made to the IESO's Process Systems & Upgrade (PSU) program, originally introduced by the IESO in 2011, that offered financial incentives for the implementation of energy efficiency and generation projects that are capital intensive.[14] As of May 1st, 2019, IESO made fossil-fueled CHP applications ineligible for incentives under this program.[15] This has led to a notable decrease of non-renewable DER applications. In 2022, only four non-renewable projects were connected, compared to 52 in 2020 and 2021. The increased regulatory and public pressures on companies to move towards cleaner sources of energy generation will likely lead to continued decline in new non-renewable installations.

2. Generation Connection Forecast

Toronto Hydro's DER forecast is separated into renewable, energy storage and non-renewable segments. For each segment, forecast DER capacity was approximated using a mathematical model that best represented recent and anticipated growth patterns, considering a combination of historical trends, project pipeline, economic environment and the current energy policies at the time of forecast.

The DER forecast assumes that no major changes to the current regulatory policy or availability of funding and incentives occur within the forecast period. Furthermore, Toronto Hydro compares its forecast results with other third-party studies and research for alignment.

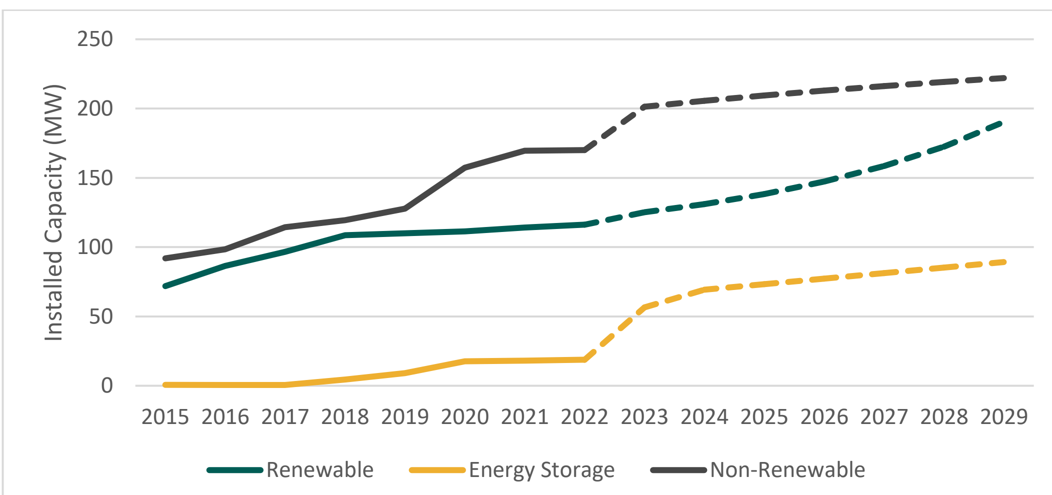

Figure 8: DER Generation Capacity (historical and forecasted) within Toronto Hydro's service territory

[14] Save on Energy, Program Requirements, "online", https://saveonenergy.ca/-/media/Files/SaveOnEnergy/Document-Archive/IF-Documents/PSUP-Program-Requirements-LT.ashx

[15] Independent Electricity System Operator (IESO), New Process and Systems Upgrades Program, "online", https://www.ieso.ca/en/Sector-Participants/Conservation-Delivery-and-Tools/Conservation-E-BLASTs/2019/05/New-Process-and-Systems-Upgrades-Program

a. Overall Forecast

Total DER projects are expected to contribute a total increase of 67 percent to total installations, reaching over 4,400 connections by the end of 2029. This represents a total DER installed capacity of approximately 516.7 MW in comparison to the 304.9 MW installed as of the end of December 2022.

Table 6: Forecast Generation Connections

Generation Type	2023	2024	2025	2026	2027	2028	2029
Renewable	2507	2690	2916	3172	3495	3858	4263
Energy Storage	44	47	53	58	66	73	82
Non- Renewable	132	137	139	141	143	145	147
Total	**2683**	**2874**	**3108**	**3371**	**3704**	**4076**	**4492**

Table *7:* Forecast Generation Capacity (in MW)

Generation Type	2023	2024	2025	2026	2027	2028	2029
Renewable	126.4	133.4	143.4	155.1	168.5	183.6	200.4
Energy Storage	56.6	60.0	73.4	77.4	81.4	85.4	89.5
Non- Renewable	198.2	212.1	215.6	218.7	221.6	224.3	226.8
Total	**381.2**	**405.5**	**432.4**	**451.2**	**471.5**	**493.3**	**516.7**

b. Renewable DER Connections

Between 2023 and 2029, Toronto Hydro forecasts over 1700 additional renewable connections (totalling over 74 MW) to the distribution system. This would bring total installed capacity to 200.41 MW. This rate of growth is in alignment with the Ontario DER Impact Study conducted by ICF in 2021.[16]

c. Energy Storage connections

Between 2023 and 2029, Toronto Hydro forecasts over 50 additional Energy Storage connections (totalling over 70.8 MW) to the distribution system. This would increase the total number of connections to 82 by 2029, and the total installed Energy Storage capacity to 89.5 MW. The pipeline projects indicate aggressive growth in energy storage connections between 2023 and 2025. This growth may be attributed to completion of projects deferred earlier during the COVID-19 pandemic.

[16] ICF Ontario DER Impact Study – January 18, 2021

Beyond 2025, Toronto Hydro believes energy storage growth will return to linear growth patterns, similar to pre-pandemic levels. This rate of growth put this forecast above the high-scenario in the Ontario DER Impact Study conducted by ICF in 2021.[17] However, due to the relatively small existing total capacity of Energy Storage currently installed in Toronto, even the connection of a single large project will lead to large statistical percentage increase in the installed base.

d. Non-Renewable Connections

Toronto Hydro's pipeline for non-renewable DER currently consists of eight projects, totalling 26.6 MW expected to be connected in 2023. Between 2023 and 2029, Toronto Hydro forecasts 28 additional non-renewable DER connections (totalling over 56.8 MW) to the distribution system. This would bring total installed non-renewable DER capacity to 226.8 MW.

While Toronto Hydro anticipates increased pressure from government and regulatory bodies to reduce the use of non-renewable sources of energy as different net zero emissions targets are approached,[18] the most common applications of non-renewable DERs do not yet have viable or technologically mature alternatives. For example, gas generators remain the preferred method of backup generation in the event of an outage for customers as they can run for longer periods of time when compared with energy storage. Renewable generation is not typically suitable for this purpose as they are dependent on the availability of wind (in the case of wind turbines) and sunlight (in the case of solar PV).

Non-renewable generation is also used for Combined Heat and Power (CHP) systems which can generate both heat and electricity. Currently, projects to make fossil fuel-based CHP systems sustainable are still in the pilot phase,[19] and not available to customers.

e. Renewable DERs Policy Considerations

DER demand is driven directly by customer behaviour and choices, which in turn can be greatly impacted by regulatory policy and the availability of funding and incentives. The FIT program is evidence of the rapid impact policy and incentives can have on the renewable DER segment. Between 2009 and 2018 when the FIT program was active, DER installed capacity increased from 1.4 MW to

[17] ICF Ontario DER Impact Study – January 18, 2021
[18] TransformTO's Net Zero 40 and the Net-Zero Emissions Accountability Act achievement of Net Zero by 2050.
[19] Newswire, Cision Canada, "online", https://www.newswire.ca/news-releases/new-combined-heat-and-power-system-will-reduce-greenhouse-gas-emissions-ghg-and-advance-enbridge-gas-hydrogen-hub-in-markham-ontario-886069080.html

108.7 MW, which represents a compound annual growth rate (CAGR) of 62.2 percent. When the FIT program ended, renewable energy growth reduced to 1.7 percent.

Some current policies and economic factors that may impact the rate of renewable DER and energy storage connections include:

- **Green Energy Tax Credit -** This tax credit, announced by the Federal Government in November 2022, allows a tax credit of up to 30 percent of the capital cost of investments in specific generation systems including solar PV and battery storage systems;[20]
- **Third Party Ownership of Net Metered Generation Facilities –** On July 1, 2022, the OEB enacted changes to enable third-party ownership of Net Metered generation facilities.[21] It is expected that this policy will increase customer accessibility to renewable generation facilities, given the high initial cost requirement. This has generally been the case in other jurisdictions where this model is well established.[22] While no third-party Net Metering applications have yet been received by Toronto Hydro, Toronto Hydro anticipates that this policy may play a key role in driving renewable DER growth during this period;
- **Low Lithium Ion Battery Cost -** Lithium Ion battery prices have decreased by more than 79 percent since 2013 and are expected to continue to decrease.[23] The combination of solar PV and energy storage allows users to capitalize on energy that can only be captured during the day, improving the usability of power generated by solar PV. Low battery cost, along with the popularity of the Net Metering program, are likely to result in increased adoption of these technologies;
- **Ultra-Low Overnight Price Plan -** In 2023, the Ontario government launched a new "Ultra-Low" overnight price plan for residential and small business customers. The new ultra-low

[20] Environment and Climate Change Canada, News Release, "online", https://www.canada.ca/en/environment-climate-change/news/2023/04/minister-guilbeault-highlights-the-big-five-new-clean-investment-tax-credits-in-budget-2023-to-support-sustainable-made-in-canada-clean-economy.html

[21] Ontario Energy Board, Forms and Templates: Third-Party Net Metering and Energy Contracts, "online", https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/forms-and-templates-third-party-net

[22] For example, the Solar Energy Industries Association (SEIA) in the US reported that 83% of residential solar systems installed over the last 4 years in New Jersey from 2017 were third-party owned (https://www.seia.org/initiatives/third-party-solar-financing)

[23] BloombergNEF, Lithium-ion Battery Pack Prices Rise for First Time to an Average of $151/kWh, "online", https://about.bnef.com/blog/lithium-ion-battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/#:~:text=LFP%20battery%20pack%20prices%20rose,cell%20prices%20observed%20in%202022

overnight rate of 2.4 cents per kWh (down from 7.4 cents)[24] provides further incentive for customers to store energy overnight and discharge during the day and is expected to lead to increased demand for energy storage systems; and

- **Industrial Conservation Initiative (ICI) program -** Large commercial and industrial customers who have opted into the Industrial Conservation Initiative (ICI) program with the IESO can reduce their global adjustment charges through peak shaving or "GA busting" using energy storage systems.

The timing, impact and probability of customer incentives relies on a number of different societal and political considerations and are difficult to predict. While this forecast does not consider future incentives not already announced, it is clear that new incentives can dramatically change the numbers presented here. As different levels of government implement net zero targets, the likelihood of intervention by government and regulatory bodies to support or promote DERs is likely to increase. As such, growth trends of DER could look very different beyond 2029.[25]

E5.1.4 Expenditure Plan

Table 8: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
Program/ Segment	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Customer Connection	36.5	92.5	75.9	71.3	75.7	84.5	90.0	95.4	100.7	106.0
Generation Connection	(0.9)	(0.1)	0.2	-	-	-	-	-	-	-
Total	**35.6**	**92.4**	**76.1**	**76.3**	**75.7**	**84.5**	**90.0**	**95.4**	**100.7**	**106.0**

E5.1.4.1 Customer Connections

Table 9: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**

[24] Province of Ontario, Ontario Launches New Ultra-Low Overnight Electricity Price Plan, "online", https://news.ontario.ca/en/release/1002916/ontario-launches-new-ultra-low-overnight-electricity-price-plan

[25] See, for example, the Future Energy Scenarios whereby the total solar PV uptake by 2025 reaches an installed capacity of approximately 430 MW in the low scenario and more than three times that in the high scenario; Exhibit 2B, Section D4, Appendix B – *Future Energy Scenarios Report* p. 67-70.

Customer Connections Gross	105.6	136.1	139.5	135.1	155.9	167.4	178.9	190.0	201.2	212.3
Customer Connections CC	(69.0)	(43.6)	(63.5)	(63.8)	(80.2)	(82.9)	(89.0)	(94.7)	(100.5)	(106.3)
Net	**35.6**	**92.4**	**76.1**	**76.3**	**75.7**	**84.5**	**90.0**	**95.4**	**100.7**	**106.0**

Expenditure in the Customer Connections segment is driven by a myriad of factors. Year to year variations are due to factors such as economic drivers and changes, the specific type of connection and associated expansion work, provincial and municipal policies regarding infrastructure, community and land revitalization projects, and the energy transition. As described below, Toronto Hydro's 2025-2029 expenditure forecast is based on historical data.

The irregular nature of expenditures in this segment is attributed to externally driven variables, which include:

1) Economic drivers, changes, and policies influence corporations in various industries (such as technology,[26] design,[27] financial services, transportation, etc.) to operate or expand in Toronto, consequently impacting investment needs and expenditures. Factors such as GDP, growth forecasts, inflation, unemployment rates, corporate tax rates, investor protection, purchasing power and credit ratings provide awareness into economic potential and the operating environment. Provincial and municipal policies regarding infrastructure and community revitalization projects (e.g. Toronto Waterfront – Port Lands, Quayside, Parliament Slip, Villiers Island), hospitals, universities, public transit projects (e.g. TTC and Metrolinx - Yonge North Subway Extension, Scarborough Subway Extension, Eglinton Crosstown West Extension, Ontario Line) may give rise to connection work and consequently create further construction and related work in the relevant project sites and surrounding areas;

2) The number, type, size, and location of connection requests received by Toronto Hydro are factors that inform whether an expansion to the distribution system is required. As elaborated in Section 3.1 above, expansion work can significantly impact program

[26] Toronto is a global hub for IT: CBRE, Scoring Top Tech Talent 2022, "online", https://mktgdocs.cbre.com/2299/957e9b99-3410-4f62-b1b1-b4a53147cee1-897668710/2022-Scoring-Tech-Talent.pdf
[27] Toronto employs the largest design workforce in Canada and third largest in North America: CBRE, Tech-30 2022, "online", https://mktgdocs.cbre.com/2299/1d1f0fcb-b1a2-443e-9277-59e1ec6b9cee-609426651/Tech-30-2022.pdf

expenditures as it typically requires a substantial amount of resources to plan and construct the infrastructure necessary to connect a customer; and

3) Capacity relief and additional capacity provisions completed under other System Access and System Renewal programs. For example:
    a) Areas with load constraints may be relieved under the Load Demand program- the resulting capacity relief will allow Toronto Hydro to connect customers more efficiently, reducing expansion requirements to the distribution system and consequently reducing connection costs;
    b) Assets replaced to current standards under the Overhead System Renewal program may indirectly include additional capacity provisions for future purposes, including where:

        (i) poles are replaced with higher or stronger poles to accommodate additional circuits without having to replace the new poles in the future; and

        (ii) additional ducts may be installed when ducts are rebuilt to leverage trenching costs and avoid future costs.

Toronto Hydro's customer charges or allowances associated with connections are established pursuant to the DSC, and Toronto Hydro's Conditions of Service. Connection asset related work, less any allowance, is paid for by the customer. Expansion asset related work is evaluated using the Economic Evaluation Model[28] to determine capital contribution and expansion deposit requirements to be met by the customer.

For the next rate period, Toronto Hydro proposes to increase its Basic Connection Fee allowance for Rate Class 1 to 5 from $1396[29] to $3059. The Basic Connection Fee has not been updated since 2009. The updated Basic Connection Fee reflects the cost of the current connection standards and includes upgraded transformation from 100kVA, to 167KVA. The upgraded transformation standard will reinforce the current overhead system and reduce barriers to electrification by supporting increased load from EV charger installation and/or home electrification. In addition, the increased allowance will also make new service connections more affordable for new residential homes.

[28] As defined in Section 3 and Appendix B of the Distribution System Code ("DSC").
[29] Fees are reviewed annually and updated with notice to customers when Toronto Hydro's Conditions of Service is revised.

The contributions filed in the last application assumed a gross spend (and capital contribution ratio of 48 percent). The average capital contribution rate for years 2020-2022 was 47.7 percent. In order to smooth any cyclical trends and better reflect actual contributions, the 2025-2029 forecast for contributions was developed by considering the average capital contribution experienced during the most recent 5-year period (i.e. 2018 to 2022) and projecting year by year specific contributions for 2025-2029 yielding an average capital contribution rate of 49.8 percent an increase of 3.7 percent above the previous filing rate.

For the 2020-2024 period, the load connection segment is forecasted to be 1.75 times the gross expenditures initially planned. As described above, recovered capital contributions were consistent with the planned ratio of 48 percent. As will be explained below, the increase in expenditures is largely attributed to a substantial increase in projects greater than 5MVA and 10MVA of demand load.

For 2021-2022 Toronto Hydro experienced a higher than anticipated increase in system access requests for large projects (>= 5MVA demand load). In that time, Toronto Hydro connected three times more incremental demand load for >= 5MVA projects than for the entire proceeding five-year rate period 2016-2020 and almost 8.7 times more incremental demand load for projects >=10MVA.

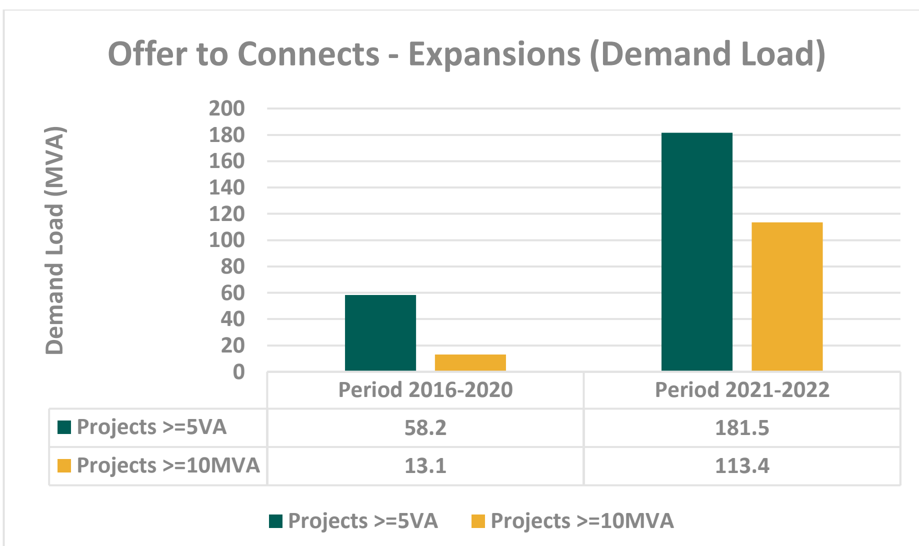

Figure 9: Offers to Connect – Expansions (Demand Load)

The increases in 2020-2021 were attributed to the emergence of unforeseen large connections across a broad spectrum of market segments including: multi-use projects (commercial-condominium), institutional infrastructure, industrial infrastructure, data centres, and transit projects (Finch West LRT). This market trend towards larger projects seeking system access is expected to continue at 2021-2022 levels through to 2024 based on the current feeder request pipeline, ongoing pre-offer to connect customer design discussions and demand load requirements. Based on Toronto Hydro's early development and Key Accounts initiatives, and direct consultation with customers, Toronto Hydro determined that planned developments for the 2025-2029 timeframe include approximately 17 to 20 projects with greater than 10MVA of demand load. These projects are progressing through the City of Toronto pipeline and development application process, drawing and review phases.

Additionally, the energy transition to clean energy, and electrification has begun creating increased demand for access to the distribution system to support customer adoption of emerging technologies such as electric vehicle charging, electric heat pumps, and electric water heaters. The increasing access requests have developed through numerous channels (Key Accounts relationships, direct customer requests, and consultant/contractors on behalf of customers) and it is expected to grow as energy transitioning matures. Identifiable EV specific projects over the 2022-2024 period include the City of Toronto on street parking project (30 locations with 53 charging ports – 2023), Toronto Parking Authority off street parking (including over 100 EV ground level charging station installed, and 47 pole-mounted stations – 2022, and 225 ground level stations in 2023). This rate of electrification within the City of Toronto is expected to grow and increase rapidly throughout the 2024-2029 period together with ongoing new building construction electrification requirements for commercial, residential and mixed-use developments.

Looking forward to the 2025-2029 period, it is forecasted that the large project (excluding data centres) segment growth will continue to grow at the same or higher levels than the 2020-2024 period. In particular, as discussed above, large projects requiring greater than 10MVA of demand load is expected to grow from one project/year (2020-2024) to approximately three to four projects per year (2025-2029) with an average incremental total demand load of 65MVA per year. Projects during this period are expected to include loading profiles which also encompass compliance with EV charging requirements. These projects are primarily comprised of large multi-use community building developments throughout the City.

Major transit projects for 2025-2029 are also expected to exceed levels experienced and expected for 2020-2024 (one to two projects for the period), and includes projects for the Yonge North Subway Extension, Scarborough Subway Extension, Eglinton Crosstown West Extension, and the Ontario Line for a total incremental demand load of approximately 150MVA over the 2025-2029 period which is approximately ten times the expected level for 2020-2024.

Based on early development and Key Account initiatives, and direct customer consultations, it is forecasted that the number of data centre service connection for the 2025-2029 period will remain the same as for the 2020-2024 period (total of three for a total incremental demand load of 107MVA), but that the data centres forecasted for 2025-2029 are larger and more complex approximately doubling the incremental demand load expected to approximately 207MVA.

The Customer Connections program is driven by customer service requests and as such, Toronto Hydro ranks and prioritizes jobs in this Program in accordance with the schedules and timelines of individual customers and service requests.

For customers requiring basic connections, prioritization is conducted on a first come, first served basis, considering the in-service date requested by the customer. This prioritization applies where Toronto Hydro has sufficient physical infrastructure, such as through overhead or underground lines, to enable the connection as well as adequate capacity on the relevant distribution feeder cable and station bus. Furthermore, customer timelines are considered to minimize disruptions or allow for efficiencies, whenever possible.

Wherever civil or electrical capacity is constrained or reliability is a concern, the connection is completed once the constraints are addressed by an expansion or system enhancement. For connections that cannot be completed without an expansion, prioritization of the work is determined in accordance with the timelines and requirements stated in the OTC.

E5.1.4.2 Generation Connections

Table 10: Historical & Forecast Program Costs ($ Millions)

	Actual		Bridge			Forecast				
Program/Segment	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Generation Connections Gross	0.8	(1.9)	(0.7)	-	-	-	-	-	-	-
Generation Connections CC	(1.7)	1.8	0.9	-	-	-	-	-	-	-
Net	**(0.9)**	**(0.1)**	**0.2**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

All project expenses and operational costs for Toronto Hydro to facilitate the DER connections are recovered from the customer through capital contributions.[30] The $0.9 million and $ 0.01 million losses incurred between 2020 and 2021 were due to changes in financial bookkeeping practices that led to discrepancy between expenditures and capital contributions in those years.

Toronto Hydro does not propose any net expenditure under this Program for the years 2025 to 2029. If during the course of the project, Toronto Hydro does not use all of the fees collected from the customer to facilitate the DER connection, Toronto Hydro will refund the difference back to the customer.

Table 11 and Table 12 below provide a breakdown of work units and costs associated with the Generation Connection program based on generation type and size.

Table 11: 2020-2024 Volumes (Actual/Bridge)

Generation Type	Actual			Bridge		Total
	2020	2021	2022	2023	2024	
Renewable <50 kW	24	51	85	170	157	**487**
Renewable > 50 kW	8	8	10	57	26	**109**
Micro Energy Storage	-	-	3	2	2	**7**
Small Energy Storage	9	2	1	2	1	**15**
Mid Energy Storage	2	-	-	9	1	**12**
Large Energy Storage	-	-	-	2	1	**3**
Small Non-Renewable	25	22	4	9	1	**61**
Mid Non-Renewable	1	3	-	7	1	**12**
Large Non-Renewable	1	-	-	-	-	**1**

[30] Work and costs associated with additional modifications to the distribution system to incorporate renewable generation into the system are discussed in the Generation Protection, Monitoring, and Control program see Exhibit 2B, Section E5.5.

Table 12: 2025-2029 Volumes (Forecast)

Generation Type	Forecast					Total
	2025	2026	2027	2028	2029	
Renewable <50 kW	179	202	259	293	325	**1258**
Renewable > 50 kW	47	54	64	70	80	**315**
Micro Energy Storage	2	3	4	4	6	**19**
Small Energy Storage	1	1	1	1	1	**5**
Mid Energy Storage	1	2	2	2	2	**9**
Large Energy Storage	-	-	-	-	-	**0**
Small Non-Renewable	1	1	1	1	1	**5**
Mid Non-Renewable	1	1	1	1	1	**5**
Large Non-Renewable	-	-	-	-	-	**0**

Toronto Hydro has a dedicated DER team that supports DER connections. This team works closely with customers to ensure the DER connection process is followed and timelines set by the Ontario Energy Board are met. Generation connections, like customer load connections, are processed and completed on a first come first serve basis.

E5.1.4.3 Cost Management

Toronto Hydro integrates the connection work with its planned construction activities to help ensure that the scope, nature and timing of the connection work does not adversely affect the utility's existing customers and planned work program.

If Toronto Hydro anticipates that load growth will require additional infrastructure upgrades beyond what is required under the expansion work for a customer service connection as set out in an OTC, the utility will include the additional system growth distribution work (which can range from installing larger circuits to rebuilding cable chambers) as a part of the project but not allocate these costs to the customer's OTC for the service connection. Such additional infrastructure upgrade project costs are allocated to the respective programs (e.g. Load Demand, Externally Initiated Plant, Overhead System Renewal, or Underground System Renewal). This coordinated approach is more cost-efficient than returning to the same area at a later date to perform additional upgrades.

An example of this approach can be found in work along Toronto's Waterfront, where the required civil work to connect new condominiums and developments was augmented to include the additional infrastructure necessary to meet future demands and system requirements that are imminently expected based on the City's Precinct Plans and progress for revitalisation projects such as the Port Lands. The development areas of the Port Lands (e.g. Villiers Island, Polson Quay and South River, McCleary District, Hearn Generating Station, Maritime Hub, Media City, East Port, South Port) includes residential, commercial, retail, and industrial land uses, combined with green space and community-based developments.

Wherever possible, Toronto Hydro also coordinates its connection work with construction activities undertaken by other utilities or municipal provincial, or federal government agencies. For example, Toronto Hydro is coordinating the expansion work for the Port Lands Revitalization Project with the City of Toronto's road allowance infrastructure construction schedule, as well planning for the Downsview park lands (City of Toronto/Canada Lands) development including servicing and infrastructure.

Where an expansion overlaps with a capital work program or another project, Toronto Hydro would connect customers under a temporary arrangement until the project is complete.

For Generation Connections, the cost for Toronto Hydro to facilitate DER connections are recoverable through customer paid fees resulting in zero net expenditures. These fees are regularly re-evaluated by Toronto Hydro to ensure that they recuperate all connection costs considering various factors like equipment cost changes, market inflation, etc.

E5.1.5 Options Analysis

E5.1.5.1 Option 1: Do Nothing

Do nothing is not an option as Toronto Hydro would be violating the DSC as well as its Distributor License.

E5.1.5.2 Option 2 (Selected Option): Customer Connections Program

As customers request access to the distribution system, Toronto Hydro endeavours to connect them in the most efficient and economic means available. Specifically, Toronto Hydro aims to connect customers from the closest access points available; where possible.

Depending on the system and customer conditions (e.g. requirements, size, location, and timelines), capacity or access may not be available. In such cases, Toronto Hydro will consider alternative solutions to connect the customer. Such alternatives may include, but are not limited to, transferring existing customers to an alternative feeder to free capacity on the feeder in question, or upgrade, extend, or install feeders, transformers, switches or other relevant equipment, as required. Should multiple options exist to connect a customer, options are reviewed with the customer and any differences (financial or technical) are explained to the customer to allow for an informed decision.

The Customer Connections program is an integral program for Toronto Hydro for the purposes of meeting customer service requests in accordance with its mandated service obligations. Without this Program, Toronto Hydro will not be able to serve and connect customers in the manner specified by its Distributor Licence and other applicable regulatory requirements.

E5.1.6 Continuous Improvement

E5.1.6.1 Productivity

In 2022, as part of a continuous improvement initiative to enhance the customer experience, Toronto Hydro created two new teams – the customer intake team and the pre-design team to streamline the customer connection process:[31]

- The customer intake team creates a single point of contact for all customer inquiries related to connections; and,
- The pre-design team acts as a single point of contact for customer to ensure all information required by the design team for large connections is collected before moving forward to the design phase.

At the end of 2023, Toronto Hydro is expected to launch the Service Request Form Enhancements on the Customer Connections portal. These enhancements will improve the customer experience by enhancing the service request form for customers to request new and existing connections from Toronto Hydro. Further details of these initiatives are described in Exhibit 4, Tab 2, Schedule 8.

To improve the customer experience and help customers better understand the availability of different service types and options, Toronto Hydro has prepared a set of public-facing brochures and guidelines. Brochures topics include “How to Power up your Home”, “How to power up your Projects”, pool clearance and underground clearance.

[31] Further details regarding these two teams can be found in Exhibit 4, Tab 2, Schedule 10.

E5.1.7 Execution, Risks & Mitigation

E5.1.7.1 Execution

Customer Connections involves the installation of connection, expansion, and/or enhancement assets, as defined by the DSC. The utility manages the work required under the Customer Connections program for Toronto Hydro. Customers or their representatives are required to consult with Toronto Hydro concerning the availability of supply, supply voltage, service location, metering, and any other details necessary to establish service.

Customers apply for new or upgraded electricity services and temporary power services in writing. Each customer provides Toronto Hydro with sufficient lead-time to ensure the timely provision of adequate electricity supply. Toronto Hydro communicates with the customer in a timely manner in accordance with the DSC and Toronto Hydro's Conditions of Service.

Pursuant to the applicable provisions of the DSC and its Conditions of Service, Toronto Hydro does not connect customers if it has safety concerns or reason to believe that the connection would affect the reliability of its distribution system. A load analysis is performed for each customer request to ensure that the requested connection would not overload Toronto Hydro assets above their rated capacity. For large connections, this analysis also includes protection and coordination studies to ensure the proper protection is in place and to avoid damage to equipment and potential safety risks.

During the consultation and design phase of a customer’s request, if a connection could potentially degrade the reliability of the relevant feeder or station, expansion work is deemed necessary to increase capacity or transfer load so that the current level of reliability is maintained.

Toronto Hydro provides customers with an OTC within 60 days from the day all required information is received. The customer is presented with a job quotation or a “short form” OTC, should the connection not require any expansion. Otherwise, the customer is provided with a “long form” OTC.

Customers are required to accept and make all OTC payments within 60 calendar days of receiving the OTC. Once an OTC is executed, the resulting work is to be carried out by Toronto Hydro resources unless the customer pursues an alternative bid where allowed by the OTC.

E5.1.7.2 Risks & Mitigation

The following are a number of risks that may affect the completion of the Program, and associated actions aimed to eliminate or manage such risks:

- **Capacity upgrade requirements**: Due to the increasing quantity and size of customer service requests, Toronto Hydro anticipates that many future connections will require expansion work to deal with capacity constraints. Typically, these expansions have long lead times that could present a challenge to Toronto Hydro in meeting the customer's required timelines for connection. The increasing complexity of connections, which may require additional capacity/equipment from Hydro One, may not allow Toronto Hydro to deliver an OTC within 60 days. Toronto Hydro will continue to:
    - Use long term forecasting, including analysis of city area and development plans in order to address growth early on and proactively upgrade or install required assets through enhancement work to the system;
    - Engage customers early on in the process to determine needs and assess impact on distribution system; and,
    - Engage with Hydro One as early as possible in order to mitigate capacity constraints which may appear on both the distribution and transmission systems.

- **Customer timelines and requirements**: Customers' changing requirements, load demand, deadlines, and delays in providing information, signing offers to connect, and providing payments present a risk to project timelines. Customers frequently require more complicated connection schemes to ensure their current and future needs are met. In addition, an expedited construction schedule by the customer and/or a strain on Toronto Hydro resources risks the utility's ability to complete the project on time and meet the customer's timeline. Toronto Hydro strives to identify and mitigate these risks early on during the design and consultation phase through early engagement, key accounts interaction, customer intake processes, and pre-design teams. This overall process educates, and prepares both the customer and Toronto Hydro on servicing challenges, finding the best solution from a technical and economic standpoint, and identifying any servicing limitations which may occur prior to the issuance of an offer to connect. Toronto Hydro communicates with the customer in a timely manner in accordance with the DSC and Toronto Hydro's Conditions of Service to ensure requests are continuously progressing. Customers are informed of expectations, timelines, and requirements early on through proper communications. Customers are also required to accept and make all OTC payments within 60 calendar days of receiving the OTC; and

- **Generation Connections:** Toronto Hydro has identified a number of constraints within its system that impact DER connections and interconnection-related decisions: 1) short-circuit capacity; 2) risk of islanding; 3) thermal limits; and 4) the lack of the ability to transfer loads between feeders during planned work. The Generation Protection, Monitoring & Control Program at Exhibit 2B, Section E5.5 describes the steps Toronto Hydro is taking to mitigate these system constraints.

E5.2 Externally Initiated Plant Relocations and Expansion

E5.2.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 54.2	**2025-2029 Forecast ($M):** 76.0
Segment: Externally Initiated Plant Relocations & Expansion	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Focus, Public Policy Responsiveness, Financial Performance, Operational Effectiveness - Reliability	

The Externally Initiated Plant Relocations and Expansion program (the "Program") captures work Toronto Hydro must undertake to relocate its infrastructure in response to third-party relocation requests to resolve conflicts between existing utility infrastructure and third-party capital construction projects. The Program also includes work that increases the capacity of Toronto Hydro's system where, in some instances, efficiencies can be achieved by integrating expansion work of the electrical system with the required relocation work. Relocation requests by third parties are usually received from those required to maintain, upgrade, expand and improve existing public infrastructure such as roads, bridges, highways, transit systems, transmission stations and rail crossings. The governmental third parties include the City of Toronto and the Ministry of Transportation of Ontario. Toronto Hydro also receives relocation requests from other agencies, such as Metrolinx, which it assesses in a fair and reasonable manner.

The City of Toronto is experiencing a period of significant infrastructure renewal, neighbourhood revitalizations, commercial development and large transit expansions. Toronto Hydro seeks to respond to relocation requests received from third parties in a safe, environmentally responsible, reliable, cost-efficient and timely manner. In pursuing this objective, the utility aims to meet its obligations under:

- The *Public Service Works on Highways Act, 1998* ("*PSWHA*");[1]
- The Distribution System Code ("DSC") section 3.1.10;

[1] RSO 1990, Ch P.49.

- The *Building Transit Faster Act, 2020 ("BTFA")*;[2]
- The *Building Broadband Faster Act, 2021* ("*BBFA*"),[3] including requirements under Ontario Regulation 410/22 made under the *Ontario Energy Board Act*, *1998* ("*OEB Act*");[4] and
- Agreements with third parties.

Typically, when relocations are required, Toronto Hydro replaces the existing facilities on a like-for-like basis. This approach represents the minimum investment required to allow Toronto Hydro to continue providing safe and reliable electricity distribution service. However, at times, the nature of the project is such that like-for-like replacements are not the most efficient or desirable option. In these cases, there will be an opportunity for Toronto Hydro to maximize construction efficiencies and increase the existing capacity at the same time a relocation project is completed. In these cases, Toronto Hydro reviews the relocation request in conjunction with its future plans, and, if efficiencies can be achieved, works with the third party to complete system expansion work in conjunction with the required relocation. When Toronto Hydro increases the capacity of its infrastructure driven by future load growth during an externally initiated relocation project, this is known as an "expansion" for the purposes of this Program.[5]

The timing, pace and spending under this Program is driven by third-party requirements outside of Toronto Hydro's control. The circumstances and discretion of third parties can cause schedules and project scopes to change. In order to mitigate against the unpredictable nature of the work in this Program, Toronto Hydro seeks base rate funding for committed capital projects only. Toronto Hydro was approved to record variances in the difference between capital spending embedded in base distribution rates and the actual spending in the Externally Initiated Variance Account.[6] The Externally Initiated Variance Account was continued through to the end of the current rate period.[7] Toronto Hydro now seeks approval to record variances between capital spending embedded in rates and actual spend over the 2025-2029 rate period in the Demand Variance Account. Further details on the Demand Variance Account can be found in Exhibit 1B, Tab 2, Section 1 – Rate Framework and

[2] SO 2020, Ch 12.
[3] SO 2021, Ch 2 Sched 1
[4] SO 1998, Ch 15 Sched B.
[5] Also known as an "enhancement" under the Distribution System Code.
[6] EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Order (December 29, 2015) at p. 50.
[7] EB-2018-0165, Toronto Hydro-Electric System Limited Decision and Order (December 19, 2019) at p. 198.

Exhibit 9, Tab 1, Section 1 – DVA Overview. This approach will allow Toronto Hydro to fund necessary non-discretionary work, while protecting ratepayers from potential over recovery.

E5.2.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by responding to relocation requests and undertaking necessary, timely and cost-efficient system expansion work to accommodate future growth and increase system access, which should reduce the frequency and duration of construction disruptions for local area residents.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by: ○ Complying with the *PSWHA*, which requires Toronto Hydro to work with prescribed entities to complete the relocation of Toronto Hydro infrastructure, when requested, and subject to the cost responsibility principles established therein; ○ Complying with the *BTFA*, where Metrolinx may require the utility to modify its infrastructure if necessary for a priority transit project; ○ Complying with the *BBFA* and associated regulations, where the Minister may require a distributor to perform work if it deems it necessary for the deployment of a designated broadband project; and, ○ Complying with section 3.1.10 of the DSC by responding to customer requests for the relocation of Toronto Hydro's assets.

Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by: ○ Obtaining, from third parties requesting distribution plant relocations, full or partial funding for newly installed/relocated assets pursuant to applicable cost sharing agreements; and ○ Combining externally initiated relocation work with expansion work where doing so provides a more prudent and cost-effective solution than conducting the expansion work at a later date.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's reliability objectives by: ○ Installing new infrastructure to current standards; and ○ Improving capacity, where required, through expansion work associated with the relocation.

E5.2.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Customer Service Requests, Capacity Constraints

E5.2.3.1 Mandated Service Obligations

The *PSWHA* requires Toronto Hydro to work with public entities requesting relocation of hydro plant in a timely manner to promote the maintenance and improvement of public infrastructure.[8] In addition, Toronto Hydro has obligations under the *BTFA and BBFA* to deliver relocation services to expedite provincial transit and broadband infrastructure projects.

E5.2.3.2 Capacity Constraints

The scope, timing and pacing of these relocation projects are driven by operational decisions of third parties that are beyond Toronto Hydro's control. Toronto Hydro reviews load demand projections in the vicinity of externally initiated relocation work to identify opportunities to increase capacity

[8] These public entities must meet the definition of "road authorities" under the *PSWHA*: "road authority" means the Ministry of Transportation, a municipal corporation, board, commission, or other body having control of the construction, improvement, alteration, maintenance and repair of a highway and responsible therefore.

during a relocation project. When capacity needs are identified, Toronto Hydro integrates expansion work into the relocation project. This offers a more cost-effective solution than conducting the expansion work after the sponsor agency has completed its project.

E5.2.3.3 Customer Service Requests

Responding to relocation requests by customers is part of Toronto Hydro's customer service obligations as set out in section 3.1.10 of the DSC. Undertaking necessary, timely and cost-efficient system expansion work in connection with such relocations allows Toronto Hydro to accommodate future growth and increase system access while reducing the frequency and duration of construction disruptions for local residents.

E5.2.3.4 Program Need

Toronto Hydro undertakes the externally initiated relocations and expansions projects solely in response to capital work initiated by third parties. Any expansion work carried out under this Program is needed to meet anticipated future load growth to allow Toronto Hydro to coordinate projects with construction work being carried out by third parties.

The projects within this Program can be divided into four broad categories:

1. Requests from road authorities governed by the *PSWHA*;
2. Requests from agencies subject to *BTFA* for transit and *BBFA* for broad brand infrastructure;
3. Requests from other agencies and customers; and,
4. Expansion work undertaken in conjunction with the relocation work.

1. Requests from Road Authorities

The *PSWHA* outlines obligations for utilities with infrastructure on roads and those entities, such as the City of Toronto and Ministry of Transportation of Ontario, that have control of the construction, improvement, alteration, maintenance and repair of a highway ("Road Authorities"). For instance, typical relocation work arising from a City of Toronto initiated project includes relocating hydro poles to enable road realignment.

The *PSWHA* establishes a framework for determining cost responsibility between the parties for the relocation work. Under this framework, the Road Authority and the utility may agree upon the apportionment of the cost of the labour employed in the relocation, but, if there is no such agreement then the equipment and labour costs are divided equally between the Road Authority and the utility, and all other costs of the work (such as material costs) are the responsibility of the utility.

For relocation project components not covered under *PSWHA* but initiated by a Road Authority, such as streetscape improvement projects, or for non-like-for-like replacements (i.e. converting overhead to underground), Toronto Hydro aims to negotiate agreements that provide greater cost recovery than the default cost apportionment provided for under the *PSWHA*.

2. Requests from Agencies Subject to *BTFA* and *BBFA*

Since the previous 2020-2024 rate application two statutes have been passed which create additional obligations on utilities regarding the relocation of utility assets: the *BTFA* and the *BBFA.*

The *BTFA* was passed in 2020 to expedite the delivery of transit projects by removing barriers and streamlining processes that may result in delays. The *BTFA* outlines obligations for utilities regarding relocation of infrastructure related to priority transit projects. The *BTFA* also provides rules for cost allocation, whereby Metrolinx and the utility may agree on the apportionment of the actual cost of the work. However, if there is no agreement, Metrolinx must bear the actual cost of the work. Toronto Hydro successfully negotiated with Metrolinx that all *BTFA* relocations will be 100 percent funded by Metrolinx.

Currently, the *BTFA* designates four projects in Toronto Hydro's service area as priority transit projects:

1. The Ontario Line;
2. The Scarborough Subway Extension;
3. The Yonge North Subway Extension; and,
4. The Eglinton Crosstown West Extension, extending from Mount Dennis.

The *BBFA* was passed in 2021 to expedite the delivery of broadband projects of provincial significance.[9] This Act outlines obligations for distributors and transmitters to complete work

[9] Under the *BBFA*, the proponent and the distributor may agree on the apportionment of the actual cost of the work. If there is no agreement, there is a formula set out in Ontario Regulation 410/22 to determine the proponents share of the costs. For further details on the cost apportionment formula see s. 7 of Ontario Regulation 410/22 made under the *Ontario Energy Board Act,* and the OEB's Guidance on Cost Apportionment for Designated Broadband Projects dated February 9, 2023.

necessary for the deployment of a designated broadband project. There are no projects currently designated under the *BBFA* within Toronto Hydro's service territory.

3. Requests from Other Agencies and Customers

Where the *PSWHA, BTFA* and *BBFA* do not apply, the initiating third-party typically funds 100 percent of the relocation costs while Toronto Hydro funds any expansion work conducted in conjunction with the relocation work. Large scale projects such as the Toronto Transit Commission ("TTC") Yonge and Bloor Station Capacity Improvement Project and Easier Access Program, are examples of major projects not subject to the *PSWHA* provisions. In these cases, the third-party funds 100 percent of the relocation work.

Metrolinx is also currently working on transit projects that are not designated under the *BTFA.* The GO Expansion project will enable electric trains on several corridors. This requires adding new tracks, new stations and overhead catenary lines.[10] This includes expanding existing electrified transit through subways and Light Rail Transit ("LRT").

Work with Metrolinx is subject to a number of crossing agreements which govern cost sharing. Toronto Hydro is working with Metrolinx to negotiate cost responsibility for the additional relocation work. If, as a result of these negotiations, Toronto Hydro must bear some of the relocation costs, these costs will be recorded in the Demand Variance Account.

4. Expansion Work in Conjunction with Relocation Projects

Expansion work carried out under this Program is needed to meet anticipated future load growth. Pursuing expansion work in conjunction with the externally initiated relocation work allows required infrastructure to be installed where future construction may be restricted due to City streetscaping, commercial developments, City-imposed road work moratoriums or conflicts with other below grade utilities such as water, sewer, gas, and telecommunications.

Incorporating expansion work into the relocation work may result in significant cost savings compared to undertaking expansion work at a later date. Expansion work completed in conjunction with relocation projects may eliminate future third-party utility relocation and coordination work, avoid additional restoration work and minimize disturbance to the general public. Further,

[10] Metrolinx, GO Expansion, "online", https://www.metrolinx.com/en/projects-and-programs/go-expansion

undertaking expansion work in conjunction with relocation work ensures that Toronto Hydro infrastructure is installed in already congested rights of way without triggering the need for City approval of encroachment exemptions under the municipal consent requirements for infrastructure clearances. For instance, within the transit corridors of the Ontario Line and Eglinton Crosstown West Extension, Eglinton LRT and Finch West LRT, Toronto Hydro is taking the opportunity afforded by these relocations to expand its existing infrastructure in preparation for the expected load growth along the LRT lines. The expansion work is scheduled to occur between 2024 and 2030.

E5.2.4 Expenditure Plan

Toronto Hydro's projected spending in this Program is based on committed capital plans from third-parties including Road Authorities, Metrolinx and the TTC. Toronto Hydro gathers information on capital projects through direct consultation with external agencies, participation in the Toronto Public Utilities Coordination Committee, and reviewing governmental and public agency publications. These capital plans and project schedules are subject to change at the sole discretion of the sponsor agencies. Any such changes could impact the timing and execution of Toronto Hydro's relocation and expansion work. The projected quantum and timing of spending shown in Table 4, below, is based on the most current information available from third parties.

Table 4: Historical, Bridge and Projected Program Spending ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Project Cost	82.8	67.6	66.1	84.8	63.9	103.7	78.5	58.0	58.8	61.2
Capital Contributions	74.1	58.3	53.2	69.6	55.7	81.1	61.8	46.1	46.7	48.6
Net Cost	**8.7**	**9.3**	**12.9**	**15.2**	**8.2**	**22.6**	**16.7**	**12.0**	**12.1**	**12.6**

Given the uncertainty associated with the projects in this Program, Toronto Hydro sought rate funding for committed capital projects only (e.g. Eglinton Crosstown LRT and Finch West LRT) in its 2020-2024 rate application in the amount of $46.1 million. Any changes to these major projects or any new projects that emerged during the rate period would increase spending under this Program. Toronto Hydro requested and received a continuation of the Variance Account for Externally Driven capital to record the difference between the capital spending embedded in base distribution rates and the actual spending in the Program over the rate period.

Toronto Hydro's incurred capital expenditure costs in the 2020-2024 rate period were approximately $54.2 million, approximately $8 million over the planned amount. During the 2020-2024 rate period, there was an increase in the number and size of relocation projects. As well, there were increased costs to complete some of the work in the 2020-2024 rate period. For example, site conditions on the John Street project necessitated the use of more costly tunnelling and shaft construction than what was previously planned to accommodate the deeper elevation of new infrastructure design in order to clear other utility conflicts.

Toronto Hydro identified a number of major projects below in section E5.2.4.1 that are to commence or continue in the 2025-2029 rate period. Given the uncertainty associated with these projects, in order to mitigate against the unpredictable nature of the work in this Program, Toronto Hydro seeks base rate funding for committed capital projects only. Toronto Hydro also requests approval to capture the difference between the capital spending embedded in base distribution rates and the actual spending over the 2025-2029 rate period in the Demand Variance Account. This approach will allow Toronto Hydro to fund necessary non-discretionary work, while protecting ratepayers.

E5.2.4.1 Major Projects

Key projects with anticipated completion in the 2025-2029 rate period, including projects which have carried over from the 2020-2024 rate period, are described below.

1. Building Transit Faster Act

Metrolinx has issued notices to relocate all existing Toronto Hydro assets to accommodate construction activities and planned infrastructure for four priority transit projects designated under the *BTFA*: the (i) Ontario Line, (ii) Scarborough Subway Extension, (iii) Yonge North Subway Extension and (iv) Eglinton Crosstown West. Additional information on the four priority transit projects designated for execution are as follows:

i. Ontario Line Subway

The Ontario Line is an estimated $17 billion investment by the Province of Ontario to expand transit in Toronto with 15 stations. As shown in Figure 1 the 15.6 km Ontario Line will run between Exhibition/Ontario Place through downtown Toronto to the Ontario Science Centre.[11]

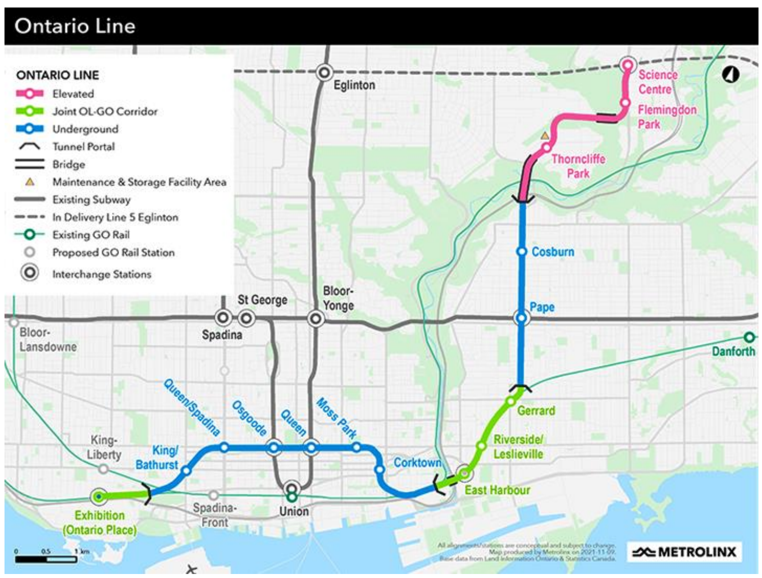

Figure 1: Proposed Map of Ontario Line

The project provides an opportunity for Toronto Hydro to undertake needed expansion work in the area. The City expects the Ontario Line corridor to experience significant growth in terms of population density and real estate developments.[12] Construction of new underground assets by Toronto Hydro within the construction zone will relieve existing area capacity constraints and meet this future growth. Completing expansion work in conjunction with the proposed construction allows Toronto Hydro to take advantage of construction efficiencies eliminating extensive future relocation work involving complex utility coordination, potential deviation on municipal consent requirements on infrastructure clearances, and disturbances to the public. Construction efficiencies may also be gained by using the same trench for multiple utilities and avoiding additional restoration

[11] Metrolinx, Ontario Line – Projects, *"online"*. https://www.metrolinx.com/en/projects-and-programs/ontario-line.
[12] City of Toronto, 2021 Census: Population and Dwelling Counts, "online", https://www.toronto.ca/wp-content/uploads/2022/02/92e3-City-Planning-2021-Census-Backgrounder-Population-Dwellings-Backgrounder.pdf.

work. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors. The project has a current estimated completion date of 2031.

ii. Scarborough Subway Extension

The Metrolinx Scarborough Subway Extension (SSE) is an estimated $5.5 billion project and will bring the TTC's Line 2 subway service nearly eight kilometres further into Scarborough, from the existing Kennedy Station northeast to McCowan Road and Sheppard Avenue (see Figure 2). The extension is set to replace Line 3 with three new stations at Lawrence Avenue and McCowan Road, Scarborough Centre, and a terminal station at McCowan Road and Sheppard Avenue. Toronto Hydro has also planned to construct new underground assets within the construction zone to relieve existing area capacity constraints and meet future growth. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors. The project has an estimated completion date of 2030.

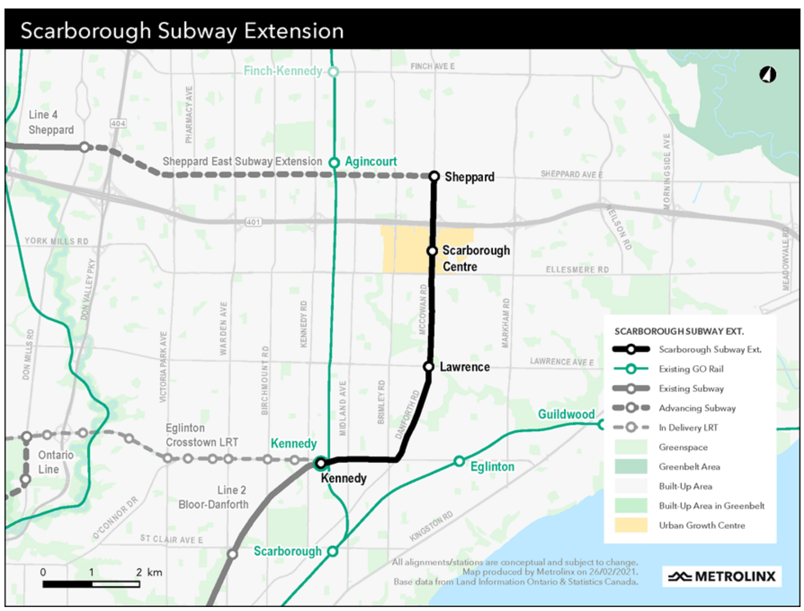

Figure 2: Proposed map of Scarborough Subway Extension

iii. Yonge North Subway Extension

The Yonge North Subway Extension is an estimated $5.6 billion project by the Province of Ontario. It will extend the TTC's Line 1 service north from Finch Station to Vaughan, Markham and

Richmond Hill. The 7.4km line will add approximately five stations. The project provides an opportunity for Toronto Hydro to undertake needed expansion work in the area up to Steeles Avenue, the limit of its service territory. The City expects the Yonge North Subway Extension corridor to experience significant growth in terms of population density and real estate developments. Construction of new underground assets by Toronto Hydro within the construction zone will relieve existing area capacity constraints and meet this future growth. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors. Construction started in February of 2023 and there is an estimated completion date of 2030.[13]

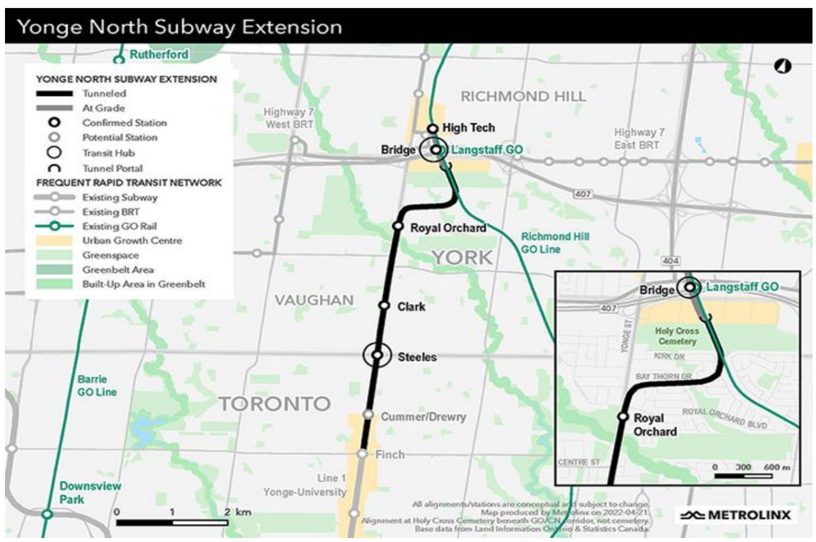

Figure 3: Proposed map of Yonge North Subway Extension

iv. Eglinton Crosstown West Extension

The Eglinton Crosstown West Extension ("ECWE") is an estimated $4.6 billion investment by the Province of Ontario that will bring rapid transit to Etobicoke and Mississauga. The western extension of the Eglinton Crosstown LRT will run approximately 9.2 km from Mount Dennis Station, west towards Renforth Drive and will operate mainly underground. Upon delivery of the ECWE, it

[13] Metrolinx, Yonge North Subway Extension, "online", https://www.metrolinx.com/en/projects-and-programs/yonge-north-subway-extension.

will create a continuous rapid transit system that spans from Scarborough, through midtown Toronto and into Mississauga.

With the new LRT, the Eglinton West LRT corridor will be more densely populated as the transit services will allow for increased growth and development. Toronto Hydro will be taking advantage of the relocation work to construct new infrastructure within the Eglinton West LRT corridor to alleviate capacity constraints and meet the anticipated load growth in the area. Expansion work will be completed in conjunction with the required relocation work causing less disruption to customers and enabling cost savings due to the elimination of road cut restoration costs. These savings are achieved through cost efficiencies in design and construction including savings in trenching costs, bulk concrete purchase savings, insurance, and digital mapping. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors. Tunneling commenced in April 2022, and the project is expected to reach completion in 2030.[14]

Figure 4: Proposed map of the Eglinton Crosstown West Extension

[14]Metrolinx, Eglinton Crosstown West Extension, “online”, https://www.metrolinx.com/en/projects-and-programs/eglinton-crosstown-west-extension

2. Metrolinx GO Expansion

The Go Expansion is a $13.5 billion investment by the Province of Ontario, to be carried out by Metrolinx, to enhance and update GO Transit infrastructure across the Greater Toronto and Hamilton Area to support more frequent, two-way, uninterrupted service via electric trains.

This initiative is a multi-year project on the GO rail network that will require extensive relocation of underground and overhead assets along the GO rail corridor in four project categories:

- **GO Electrification**: utilizing an overhead catenary system at 25 kV to operate electric motor trains and phase out diesel trains;
- **Grade Separation**: elevating the rail corridor to separate rail crossings from other modes of transportation;
- **GO Expansion**: expansion of rail tracks and associated infrastructure (i.e. tracks, rails and signals) to facilitate improved uninterrupted service; and
- **GO Station**: construction of new platforms, buildings, stations, traction power stations, parking and maintenance storage facilities to build a connected transit network.

As part of this project, Metrolinx requires the relocation of Toronto Hydro assets to meet infrastructure clearance requirements and to facilitate infrastructure, equipment and construction activities over the course of the proposed 10-year program. Figure 5 shows a typical GO Transit grade separation.

Figure 5: Grade Separation at Davenport Diamond

During the 2020-2024 rate period, Toronto Hydro has and will continue to execute Utility Preparatory Activities for the early and complementary works phase. In 2023, Toronto Hydro began investigating approximately 100 conflicts related to the development phase and scoped out approximately 35 relocation projects expected to be completed between 2023 and 2030.

Toronto Hydro is also developing a number of projects to take advantage of efficiencies in carrying out necessary expansion work in parallel with the required relocation work. The expansion work involves the construction of new infrastructure within the construction zone of the GO rail corridor and stations. The timing of the proposed work is dependent on the priority and construction of the grade separation, track expansion, electrification and station work determined by Metrolinx.

3. TTC Easier Access Program

The TTC initiated the Easier Access Program with the goal of making all of its services and facilities, including key subway and Scarborough Rapid Transit stations, fully accessible to persons with disabilities. The *Accessibility for Ontarians with Disabilities Act*, *2005* ("*AODA*") requires that all public facilities and services are accessible by 2025.[15]

Significant subway station infrastructure is impacted by the need for *AODA* compliance, including the requirement that subway stations be constructed in a tiered configuration, similar to the one set out in Figure 6. In total, 13 stations were originally included in the program. Since the last rate application, the program has expanded to include a total of 16 stations. Many of the impacted stations are located in the downtown area necessitating relocation of Toronto Hydro's infrastructure. Toronto Hydro has already completed relocation work for five stations. Although these projects were initially scheduled to be completed entirely during the 2020-2024 rate period, there will be some carry over into the 2025-2029 rate period. Toronto Hydro is also evaluating opportunities for expansion.

[15] SO 2005, Ch 11.

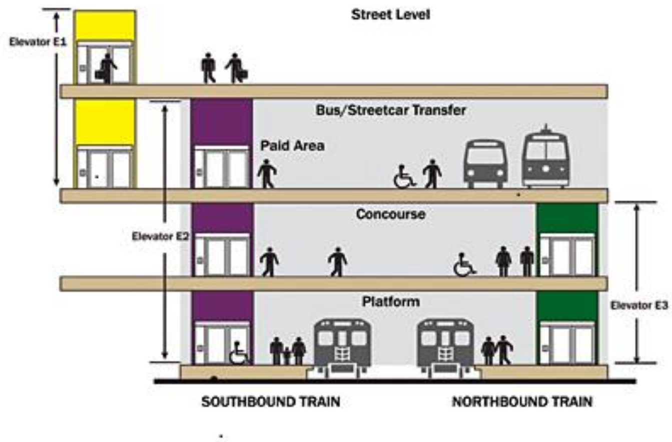

Figure 6: TTC Easier Access Station Concept

4. TTC Bloor-Yonge Station Capacity Improvements

The TTC is planning to modify and expand the existing Bloor-Yonge Station, the busiest station on the TTC. The project will increase and reconfigure existing below-grade subway platforms and add a new platform to address current congestion and accommodate future TTC ridership and neighbourhood density. This project will require the relocation of existing Toronto Hydro infrastructure. Early works are underway, and the project is expected to continue into the 2025-2029 rate period. Toronto Hydro will be reviewing the project for expansion opportunities.

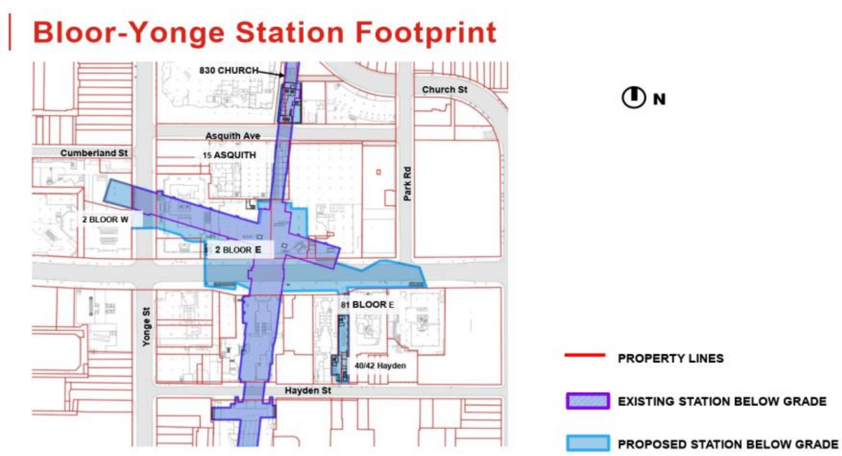

Figure 7: TTC Bloor-Yonge Station Capacity Improvements Concept-Footprint

5. City of Toronto Projects

The City of Toronto has approved a 10-year capital budget and plan of $49.26 billion for 2023-2032 which includes a variety of local and City-wide projects dedicated to the modernization, transformation and renewal of the City. [16] The City has approached Toronto Hydro to relocate the utility's infrastructure in conflict with a number of these projects. There are currently 42 active relocation projects, including those in connection with major development initiatives such as:

- **Basement Flood Protection Program ("BFPP"):** The City's BFPP is a multi-year program to reduce the risk of flooding by making improvements to the sewer system and overland drainage routes, increasing the resilience of the City to climate change including hazards such as flooding and heat.[17] The capital budget for the program is $2.1 Billion between 2023-2032.[18] The City of Toronto has requested that Toronto Hydro relocate its assets in order to accommodate sewer and watermain installations. The applications received to date are for relocations in Toronto's midtown. It is expected that there will be requests related to the program in other parts of the city.
- **City Bridge Rehabilitation Program:** The City of Toronto has over 900 bridges and culverts. The City's 2023-2031 Capital Plan has increased funding by $75.3 million over 2023-2031 to maintain the state of good repair of bridge and culvert infrastructure.[19] Repairs to city bridges typically include repairs to the concrete structure, removal and replacement of deteriorated expansion joints, cleaning and coating of steel girders, bearing replacement, and removal and replacement of barrier walls. Toronto Hydro has underground and overhead civil and electrical infrastructure situated within or upon the City's bridges and culverts that conflict with bridge rehabilitation work requiring relocation. In response to requests from the City, Toronto Hydro will temporarily or permanently relocate its infrastructure to accommodate City work.

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[16] City of Toronto, 2023 Budget Launch Presentation https://www.toronto.ca/legdocs/mmis/2023/bu/bgrd/backgroundfile-230875.pdf
[17] City of Toronto, Basement Flooding Protection Program, https://www.toronto.ca/services-payments/water-environment/managing-rain-melted-snow/basement-flooding/basement-flooding-protection-program/
[18] City of Toronto, 2023 Program Summary Toronto Water https://www.toronto.ca/wp-content/uploads/2023/04/94eb-2023-Public-Book-TW-V1.pdf
[19] City of Toronto, 2023 Program Summary Transportation Services https://www.toronto.ca/wp-content/uploads/2023/04/94ec-2023-Public-Book-TS-V1.pdf

A number of projects are put forward every year by the City in connection with its capital plan. With continued City building initiatives and population growth projections, Toronto Hydro anticipates that third-party relocation activity will remain high during the 2025-2029 rate period as a result of City council budgetary approvals.

6. Waterfront Toronto

The Waterfront Secretariat leads the Toronto Waterfront Revitalization Initiative on behalf of the City of Toronto, as well as federal and provincial partners. There are number of projects run by Waterfront Toronto, including the Quayside development. Quayside is a 4.9-hectare (12-acre) area at the foot of Parliament Street, comprising about 3.2 hectares (8 acres) of developable land across five development blocks, as well as parkland, open space and future roads. Quayside will act as a hub, linking nearby neighbourhoods like St. Lawrence, the West Don Lands, the Distillery District, Bayside, and the future Villiers Island.[20]

As part of this development, Waterfront Toronto is proposing utility relocations, streetlighting, streetscape and development along Queens Quay between Bonny Castle and Parliament Street. The relocation work is expected to be completed in the 2025-2029 rate period. Toronto Hydro will be exploring expansion opportunities provided by this project.

E5.2.4.2 Upcoming Projects

Additional projects that are still in preliminary stages may emerge in the current or next rate period. Government and public agencies such as Metrolinx, TTC, and the City of Toronto have approached Toronto Hydro regarding their initiatives to expand and improve transit and to revitalize public space including, but not limited to, the following projects:

- **Metrolinx**: On Corridor Works project will transform the GO Transit rail network in the Greater Toronto and Hamilton Area over the next decade into a system that will deliver two-way all-day service every 15 minutes over core segments of the Go Rail network.
- **TTC/Waterfront Toronto**: Expansion of Union LRT and Queens Quay LRT stations to accommodate additional streetcar lines and passengers, including construction of a high order streetcar line in a dedicated transit right-of-way.

[20] Waterfront Toronto, Quayside https://www.waterfrontoronto.ca/our-projects/quayside

E5.2.5 Options Analysis

E5.2.5.1 Option 1: Completing Externally Driven Relocation Work Only

Toronto Hydro is obligated to relocate its electricity distribution equipment in response to road authorities defined under the *PSWHA* and for projects subject to *BTFA* and *BBFA*, as well as respond to relocation requests by third parties in a fair and reasonable manner. In general, when relocations are required, Toronto Hydro replaces the pre-existing facilities on a like-for-like basis. This approach constitutes the minimum investment on the part of Toronto Hydro to continue providing safe and reliable electricity.

E5.2.5.2 Option 2 (Selected Option): Completing Externally Driven Relocation Work and Expansion Work

Sometimes the nature of a project is such that it is not the most efficient or beneficial option to undertake only relocation work. Upon receipt of a relocation request, Toronto Hydro reviews the future capacity needs in the area and evaluates whether there are opportunities for construction efficiencies available to support undertaking expansion work along with the relocation work. An example of how expansion and relocation work may be combined to maximize efficiencies is the Port Lands Flood Protection Initiative (PLFP).

Upon being advised of the project by the Waterfront Toronto, and the need to relocate its infrastructure, Toronto Hydro reviewed its capital plan to identify expansion work opportunities that could be executed along with the relocation work. Toronto Hydro performed a system analysis to determine expected load growth on the feeders in the area. In reviewing the current feeder loading conditions and approved loads through customer connections and factoring in contingency scenario loading, Toronto Hydro determined that by 2027, local feeders would be heavily loaded, requiring relief. To accommodate this anticipated growth, expansion work was integrated into the work plan to be executed during plant relocation initiatives.

Executing expansion work in coordination with the Waterfront Toronto's capital work was determined to be preferable to just undertaking the relocation work for the following reasons:

- It often is less expensive to construct new civil infrastructure to support the expected load growth in the area if such work is undertaken in conjunction with the relocation work required by the Waterfront Toronto's project. If the expansion work is undertaken in the future there would be a need for increased coordination initiatives with third-party utilities, more potential for deviation from municipal consent requirements on infrastructure clearances and additional civil construction and restoration work in the area.

- The City's road cut moratorium could prevent Toronto Hydro from installing additional infrastructure when needed to address the expected load growth. The City of Toronto imposes a five-year moratorium on road cuts in an area after road resurfacing is completed. Breaking the moratorium requires City approval and payment of a fee. Failing to complete expansion work during the relocation phase of a project could lead to Toronto Hydro having to install costlier and less optimally located facilities to meet the anticipated demand.
- Completing the expansion work and the relocation work together avoids prolonged disturbances to the residents and businesses in the neighbourhood.

E5.2.6 Distribution Grid Operations Consultation

Consultation with Toronto Hydro's Distribution Grid Operations ("DGO") Department, which coordinates all work on the distribution system, early in the design process improves outcomes for third parties and customers more broadly. Early consultation allows the DGO to sequence work on feeders to accommodate third-party relocation work more quickly while minimizing disruptions to customers in the area. The DGO also provides an operational perspective during design review. DGO is able to identify design modifications to improve system reliability early on, thereby avoiding any delay to the overall project.

E5.2.7 Execution Risks & Mitigation

Toronto Hydro's projected spending in this Program is based on a combination of deferred projects from the last rate period, future committed projects and anticipated projects. There is risk that projects in these categories or their timing may be modified or may not materialize as anticipated. In addition, new projects can emerge, adding to program costs. To mitigate the effects of these risks for ratepayers, Toronto Hydro requests approval to record variances in the Demand Variance Account.

The projects proposed under this Program are largely dictated by the schedule and plans of third parties. Third parties often face their own constraints with respect to the execution and completion timelines for their projects. To accommodate work on projects, and ensure that projects are completed within the timelines requested by customers, Toronto Hydro may undertake work during off-peak hours on evenings and weekends, as necessary. Toronto Hydro constantly monitors changes to codes, bylaws and Legislation which impacts its relocation operations to ensure that its processes and standards align with requirements.

E5.3 Load Demand

E5.3.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 120.9	**2024-2029 Cost ($M):** 236.3
Segments: N/A	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Operational Effectiveness - Safety	

With increasing land development and growth in Toronto Hydro's service territory, the Load Demand program (the "Program") aims to alleviate emerging capacity constraints to ensure the availability of sufficient capacity to efficiently connect customers to Toronto Hydro's distribution system. In doing so, the Program also seeks to minimize the effect of load growth on existing customers. Toronto Hydro's investments in this Program enable the operation of its distribution system under first contingency scenarios, as well as the minimization of potential switching restrictions during summer peak conditions (which can impede the utility's ability to execute maintenance and capital work during summer months).[1] This Program is a continuation of the activities described in the Load Demand program in Toronto Hydro's 2020-2024 rate application.[2]

More specifically, the Program alleviates overloaded equipment and capacity constraints on the distribution system through:

- Load transfers to relieve station bus overloads;
- Feeder cable upgrades and load transfers to improve capacity and asset utilization;
- Equipment upgrades to increase available capacity and reduce the number of switching restrictions experienced during the summer peak; and
- Civil enhancements to remove system bottlenecks and support additional electrical capacity.

[1] " First contingency" occurs when any one primary feeder, transformer, or other critical equipment is lost, either due to a fault or planned outage.
[2] EB-2018-0165, Toronto Hydro-Electric System Limited Application (filed August 15, 2018, updated April 30, 2019), Exhibit 2B, Section E5.3.

E5.3.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Customer Focus	• Contributes to the sustainment of service connection targets established by the OEB (i.e. the Electricity Service Quality Requirements) for new residential, small business services, and high voltage services by undertaking targeted capacity upgrades in areas of high load growth in the downtown and Horseshoe area. • Contributes to customer satisfaction results by providing large customers flexibility in scheduling substation maintenance by reducing summer peak switching restrictions.

Operational Effectiveness - Reliability	• Contributes to maintaining Toronto Hydro's System Capacity measure, and reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by:
	    ○ Improving restoration capabilities and reducing customer interruptions by providing additional capacity or maintaining spare capacity through cable upgrades and load transfers;
	    ○ Improving restoration capabilities in the downtown or Horseshoe systems by offloading highly loaded feeders;
	    ○ Improving system reliability by reducing the risk of failures due to highly overloaded equipment through mitigation of expected bus overloads; and
	    ○ Improving downtown reliability by maintaining or reducing the number of heat restricted feeders.

Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety performance objectives (as measured through measures like Total Recordable Injury Frequency) by reducing the failure risk of overloaded infrastructure to Toronto Hydro workers and members of the public.

E5.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Customer Service Requests, Reliability, System Efficiency

E5.3.3.1 Mandated Service Obligations

As per sections 3.3.1 and 4.4.1 of the Distribution System Code ("DSC"), Toronto Hydro is required to ensure its distribution system can support projected load growth while maintaining reliability and quality of service for customers on both a short-term and long-term basis. The utility must also connect new customers within the timelines prescribed by the OEB's service quality standards without adversely affecting the quality of distribution services for existing customers.[3] The OEB requires 90 percent of connections to be completed on time. Toronto Hydro achieved 99.9 percent of new residential and small business services completed within the prescribed timelines, and 99.1 percent of new high voltage connections completed within the prescribed timelines. The investments in this Program are specifically targeted to meet the OEB's service quality standards.

To satisfy these requirements, Toronto Hydro must maintain sufficient capacity on its system to keep pace with load growth and to ensure that its assets are not overloaded (i.e. an overloaded bus is defined as reaching 95 percent of its firm capacity under normal and emergency operating conditions). Highly loaded feeders in the downtown are defined as feeders that exceed cable ratings under contingency, assuming peak customer loads and a coincidence factor of 1 (i.e. all customers peak at the same time). In the Horseshoe, highly loaded feeders are defined as those with peaks of 400A, which is the standard planning practice as it leaves at least one third of a feeder's capacity available to support tie feeders under contingency.

The rapid influx of dense load in the downtown core and Horseshoe areas (see section E5.3.3.2 for more details) poses a challenge to Toronto Hydro's ability to meet its service requirements. Over the 2025-2029 rate period, Toronto Hydro expects that rapid growth will cause multiple buses to reach their rated capacity. The forecasted growth in the distribution system is based on the Toronto Hydro's Station Load Forecast. The actual demand will vary based on the actual realization of load on the system. This can depend on multiple factors and emerging trends such as electric vehicle

[3] Section 7.2 of the *Distribution System Code* requires Connection of New Services: low voltage (<750 Volts) within 5 business days and high voltage (>750 Volts) within 10 business days. Ontario Energy Board, *Distribution System Code* (August 2, 2023).

("EV") uptake and pacing of heating electrification. Section E5.3.5 Options Analysis explores how future energy scenarios can impact the requirements of this Program.

As discussed in greater detail below, critical parts of Toronto Hydro's distribution system (such as the Downtown and Central Waterfront Area in Table 4), which service a large amount of load or are experiencing high growth, are serviced by feeders that are already highly loaded and at risk of overloading in the upcoming years. Growth in these areas has been driven in large part by multiple storey residential condominiums, mixed use buildings and large commercial developments. If no action is taken to alleviate constraints, load shedding will be required during the summer peak period to mitigate the risk of failure from overloaded equipment. This involves dropping customer loads when the feeders or the equipment that supply them are overloaded so that a tolerable loading level can be maintained. Supplying customers through highly loaded feeders reduces the level of reliability, thereby causing Toronto Hydro to fail in meeting a top priority of these customers as identified through customer engagement.

E5.3.3.2 Customer Service Requests

Toronto Hydro receives customer requests for service connections every time there is a new residential, industrial, or commercial development, or when upgrades are required for an existing connection. Applications for Service are processed as part of the Customer Operations program.[4] In most cases, system planner input is required to determine how to service the customer in the most efficient manner. In constrained areas of the system, the utility's ability to respond to customer service requests within the OEB-prescribed timelines, without affecting the quality of service for existing customers, is largely dependent on the investments made in this Program.[5] Toronto Hydro utilizes the City of Toronto's land planning information to help assess which areas of the system are in most urgent need of additional capacity to accommodate customer service requests in a timely and cost-effective manner.[6]

Figure 1 shows the load additions (connection applications involving new or increased load) submitted to Toronto Hydro from 2018 to 2022 by geographical region. Figure 2 shows the resulting load impact in each region of the City.

[4] Exhibit 4, Tab 2, Schedule 8.
[5] *Supra* note 3.
[6] City of Toronto, *Development Pipeline 2022 Q2* (February 2023), « online », https://www.toronto.ca/wp-content/uploads/2023/02/92b5-CityPlanning-Development-Pipeline-2022-Q2.pdf

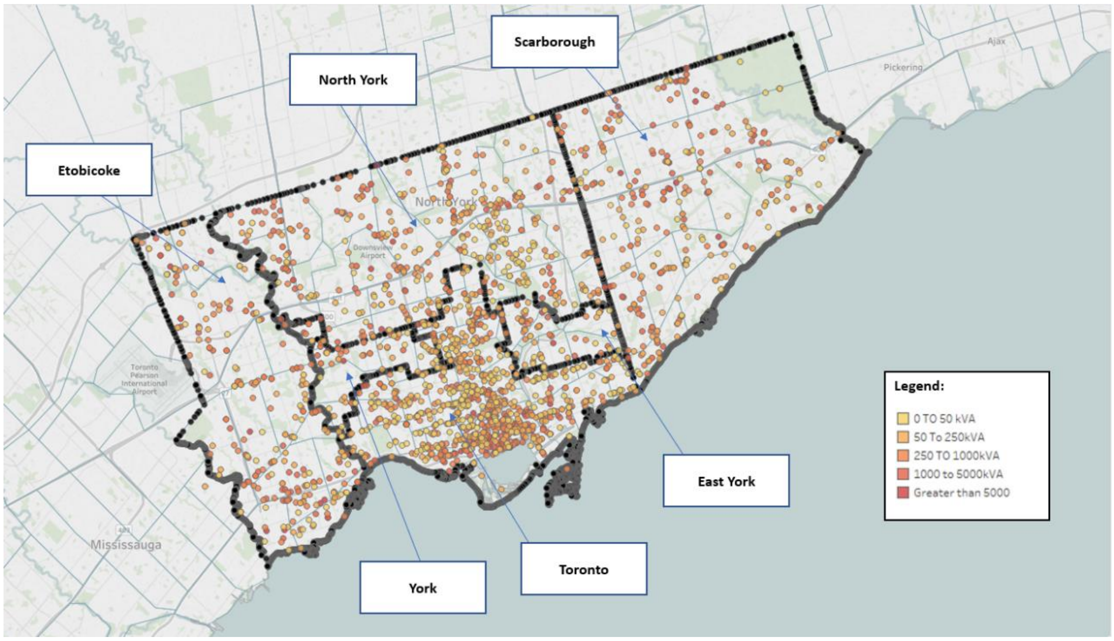


Figure 1: Load Additions in the City of Toronto during the 2018-2022 Period

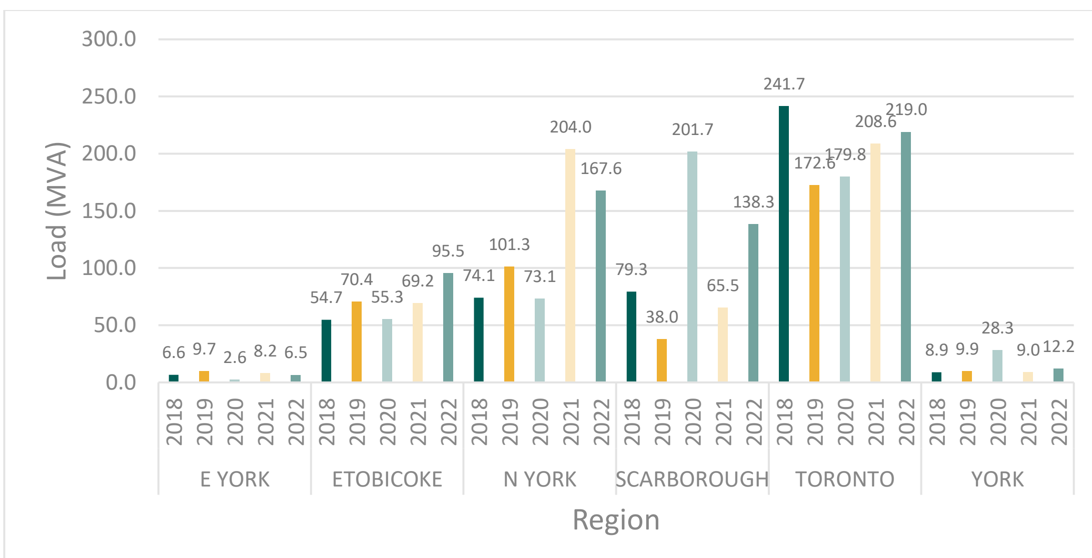


Figure 2: Load Additions by Region during the 2018-2022 Period

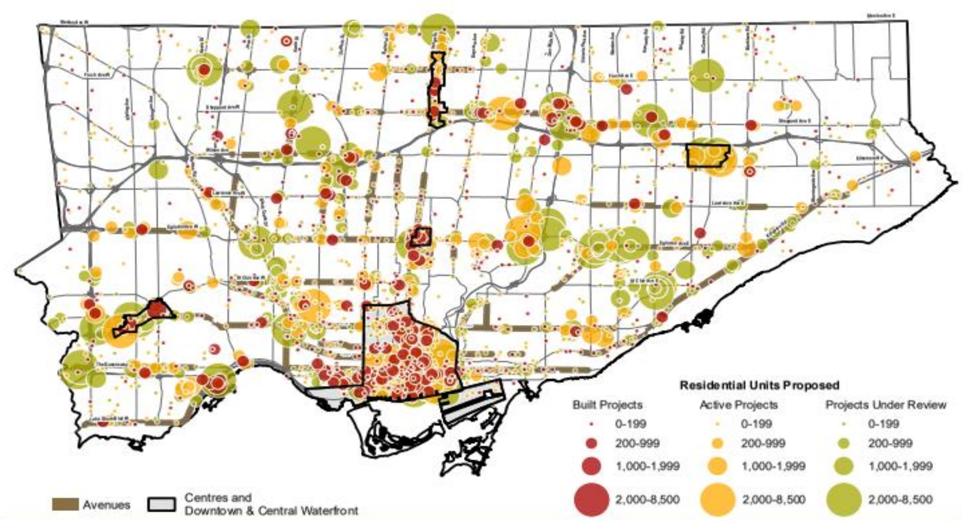
The City of Toronto is experiencing an increase in development which is expected to continue throughout the 2025-2029 rate period. Table 4 below provides a summary of the projects submitted to the City of Toronto's Planning Division between 2017 and 2022 Q2, and Figure 3 is a map of the residential units proposed over this period.

Table 4: Proposed Projects in the City of Toronto (2017-2022 Q2)[7]

	Built	Active	Under Review	Total in Pipeline	% of Total	% of Growth Areas
City of Toronto	**622**	**879**	**912**	**2,413**	**100.0%**	
Growth Areas	**394**	**549**	**605**	**1,548**	**64.1%**	**100.0%**
Downtown and Central Waterfront	142	205	179	**526**	21.7%	31.5%
Centres	30	48	47	**125**	5.2%	14.5%
Avenues	149	209	279	**637**	26.4%	28.3%
Other Mixed Use Areas	73	87	100	**260**	10.8%	25.6%
All Other Areas	228	330	307	**865**	**35.9%**	

Source: City of Toronto, City Planning: Land Use Information System II

Development projects with activity between January 1, 2017 and June 30, 2022. Built projects are those which became ready for occupancy and/or were completed. Active projects are those which have been approved, for which Building Permits have been applied or have been issued, and/or those which are under construction. Projects under review are those which have not yet been approved or refused and those which are under appeal.



Source: Land Use Information System II
Development projects with activity between January 1, 2017 and June 30, 2022. Built projects are those which became ready for occupancy and/or were completed. Active projects are those which have been approved, for which Building Permits have been applied or have been issued, and/or which are under construction. Projects under review are those which have not yet been approved or refused and those which are under appeal.

Prepared by: Toronto City Planning Division, Planning Research and Analytics - February, 2023

Figure 3: Residential units proposed (2017-2022 Q2)

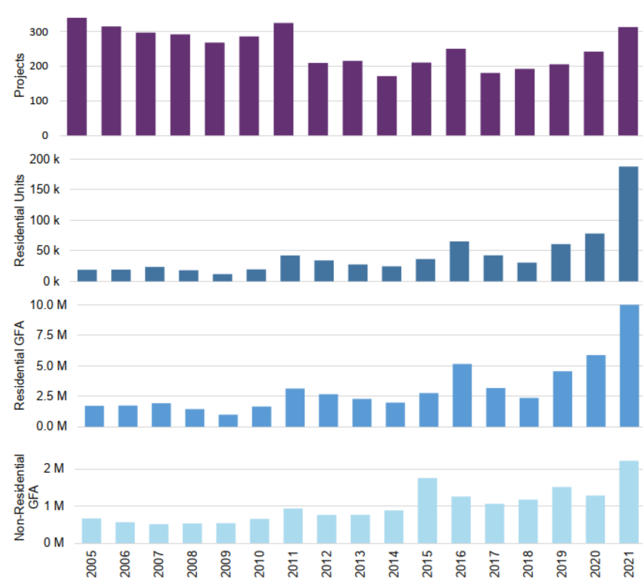
As illustrated in Figure 3, the majority of the growth is focused on the downtown system, particularly the Downtown and Central Waterfront area, where 43,513 residential units have been built as of the end of 2022 Q2 and 180,652 units are in the pipeline for future development. Another area

[7] *Supra* note 6.

experiencing strong growth in the downtown system is the Yonge-Eglinton Centre, with 38,361 units in the pipeline.

In the Horseshoe area, Sheppard East Subway Corridor, Etobicoke Centre, North York Centre, and Scarborough Centre have experienced development growth which is expected to continue: (i) in the Sheppard East Subway Corridor area, 22,699 units are in the development pipeline; (ii) in the Etobicoke Centre area, 17,575 are in the development pipeline; (iii) in the North York Centre area, 12,330 are in the pipeline; and (iv) in the Scarborough Centre area, 29,260 are in the pipeline.[8]

The number of projects submitted to the City of Toronto have remained relatively consistent over the years, ensuring a steady influx of projects and a healthy pipeline of projects. However, the number of residential units proposed and overall Gross Floor Area ("GFA") of the projects have increased substantially over the years, indicating each project has become larger and more complex overall. Figure 4 shows the trend of applications over the years. For Toronto Hydro, these large projects create single points of concentrated load that require detailed analysis and consideration when planning for their connections and managing system load overall.



Source: City of Toronto, City Planning: Land Use Information System II

Development projects submitted each year from 2005 to 2021, and the total number of residential units, residential GFA, and non-residential GFA proposed. Residential and non-residential GFA is in square metres.

Figure 4: Trend of Projects, Residential Units and GFA by Application Intake Year, 2005 to 2021

[8] *Supra* note 7.

Therefore, Toronto Hydro expects a steady stream of customer service requests for new connections over the 2025-2029 rate period and beyond. To meet these requests in a timely and cost-effective manner, and maintain reliability and quality of service for existing customers, Toronto Hydro must invest in infrastructure upgrades and load transfers to alleviate capacity constraints. In particular, Toronto Hydro must focus its efforts in the downtown and Horseshoe areas where concentrated growth is straining the distribution system by overloading station buses, feeders, and transformers.

E5.3.3.3 System Reliability and Efficiency

This Program aims to ensure that the system has enough capacity to restore customers during contingency events and that asset failure and loss of supply due to overloading are prevented. Operating assets above their rated capacity for prolonged durations increases the risk of failure and corresponding loss of supply to customers. These conditions can lead to the premature failure of primary overhead conductors and undersized legacy assets (e.g. underground paper insulated lead-covered "PILC" cables), that were installed over 35 years ago when standard trunk cables were approximately 30 percent smaller and had a 25 percent lower current capacity. Since 2012, Toronto Hydro's distribution system has experienced 293 cable and splice failures on legacy PILC cable. Where cables are at the largest standard size, instead of cable upgrades to alleviate overloads on the feeders, load transfers to other feeders with capacity will be considered.

Overloaded assets pose reliability and public safety risks. For example, the temperature of conductors and cables increases when they are overloaded which reduces the conductor's tensile strength.[9] Loss of the rated tensile strength can cause significant sagging of an overhead feeder line, which makes it more susceptible to external contacts and safety requirement violations.[10,11] Similarly, underground cables, such as the cross-linked polyethylene ("XLPE") cable used in the downtown system, soften as their temperature increases, particularly in areas where the insulation is under

[9] K. Adomah, Y. Mizuno and K. Naito. "Probabilistic assessment of the reduction in tensile strength of an overhead transmission line's conductor with reference to climatic data." *IEEE Transactions on Power Delivery*, vol.15, pp.1221-1224, 2000.

[10] F. Jakl and A. Jakl. "Effect of Elevated Temperatures on Mechanical Properties of Overhead Conductors under Steady State and Short-Circuit Conditions." *IEEE Transactions on Power Delivery*, vol. 15, pp. 242-246, Jan. 2000.

[11] Minimum Safety Clearance as in Toronto Hydro standard 03-2000 Overhead – Minimum Vertical Separations, where the exact clearance depends on the configuration of the pole, the type of attachments on it, and primary voltage.

mechanical stress (e.g. bends in the route), leading to deformation of the cable. This in turn can lead to electrical failures resulting in outages.[12]

E5.3.3.4 Addressing Drivers and Need

To meet the increasing need for capacity, ensure system reliability and efficiency, and meet the mandated service obligations, four types of work are carried out under this Program:

- **Bus Level Load Transfers**: load transfers between station buses to alleviate overloaded buses. [13]
- **Feeder Level Load Transfers and Upgrades**: transferring loads between feeders to alleviate overloaded feeders or upgrading undersized feeder trunks to the current standard.[14]
- **Equipment Upgrades**: carried out in areas like network vaults to increase unit size and associated capacity, which may reduce the number of switching restrictions experienced during summer peaks.
- **Civil Enhancements**: carried out in duct banks and egress cable chambers to enable capacity upgrade by allowing for more feeders to be installed.

1. Bus Level Load Transfers

Toronto Hydro plans to execute targeted load transfers on station buses that are expected to become overloaded based on Toronto Hydro's Station Load Forecast and those where opportunities will arise to redistribute load with adjacent station buses.[15]

Table lists the specific station buses planned for bus level load relief during the 2025-2029 rate period, and Figure shows the stations' locations. The station bus can be relieved by expanding the capacity of the bus through bus expansion, or by relieving the load of the bus through bus transfers. Bus transfers can be performed by transferring load between buses within the same station or to another station in the area. Additionally, bus balancing can be achieved during transfers to ensure that the bus capacity within transformer stations is optimized.

[12] S. H. Alwan, et al. "Factors Affecting Current Ratings for Underground and Air Cables." *International Journal of Energy and Power Engineering,* vol. 10, pp. 1422-1428, 2016.
[13] **Bus** – A rigid, large conductor usually in substations, to provide a quick and convenient means of rearranging circuit connections to keep power flowing or to restore power after an outage.
[14] **Feeder** – A distribution circuit carrying power from a substation to customers. Feeders consist of circuits and other electrical equipment supported by civil infrastructure like poles and ducts.
[15] Exhibit 2B, Section E7.4.

The completion of Copeland TS Phase 2 under the Stations Expansion program will have the potential to enable load relief at Esplanade TS, Strachan TS, Windsor TS, Cecil TS, and Terauley TS. [16,17] For these stations, civil and cabling work to enable the transfers is planned to be undertaken before Copeland TS Phase 2 is energized, so that the full benefits of Phase 2 can be realized immediately upon its energization. Relief for Horner TS and Manby TS will follow in the 2025-2029 rate period after the expansion of Horner TS is completed during the 2020-2024 rate period.

Table 5: Station Buses Planned for Relief within 2025-2029

Station	Bus	Estimated Load to Transfer (MVA)	Area
Basin	*A7-8*	15 – 25	Downtown
Bathurst	*J&Q*	5 – 20	Horseshoe
Bermondsey	*B&Y*	10 - 25	Horseshoe
Bridgman	*A1-2B*	5 -15	Downtown
Copeland	*A1-2CX*	5 – 15	Downtown
Dufferin	*Note 1*	5 – 15	Downtown
Esplanade	*Note 2*	10 - 20	Downtown
Fairbank	*B & Q*	15 – 30	Horseshoe
Finch	*B&Y, J&Q*	25 - 55	Horseshoe
Horner	*B&Y*	25 - 40	Horseshoe
Leslie	*B&Y*	25 – 40	Horseshoe
Manby	*B&Y, Q&Z*	20 - 50	Horseshoe
Rexdale	*B&Y*	5 - 20	Horseshoe
Runnymede	*J&Q*	15 – 30	Horseshoe
Sheppard	*E&Z*	5 – 20	Horseshoe
Terauley	*Note 2*	10 - 20	Downtown
Windsor	*Note 2*	10 - 20	Downtown

Note 1: Targeting bus supplying feeders in area bounded by St. Clair Ave, Queen Street W, Bathurst Street, and Keele St.

Note 2: Stations that are scheduled for Relief as part of Copeland Phase II expansion.

[16] *Ibid.* Copeland TS Phase 2 is expected to be completed by 2023/2024.
[17] Not all stations listed are addressed through the Load Demand program.

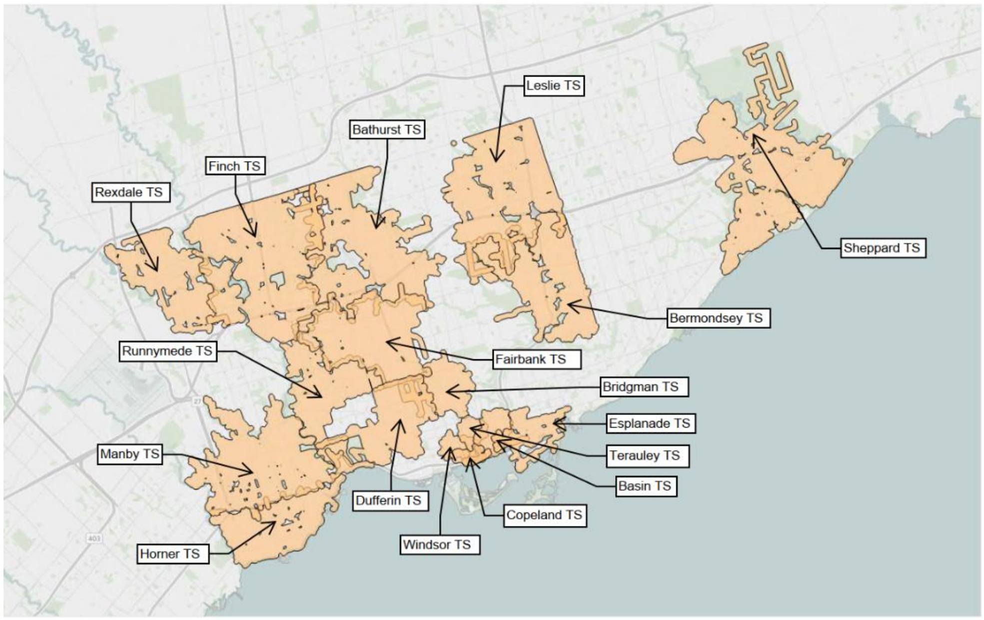


Figure 5: Stations Targeted for Relief during the 2025-2029 Rate Period

If the buses outlined in Table above are not relieved, it may not be possible to connect new customers to these station areas. As a result, Toronto Hydro may need to supply new service requests in the areas serviced by these stations from adjacent buses or stations, potentially resulting in system inefficiencies, materially higher connection costs, and longer timelines to complete the work. For example, capital contributions from connecting customers are required when revenue from their demand does not cover the cost of expansion work, as determined by the Economic Evaluation Model.[18] This may occur when significant expansion work is required for smaller loads.

Station bus load forecasts are re-evaluated annually.[19] Based on updated results, it may be necessary and prudent for Toronto Hydro to reprioritize load transfers. Some of the buses that Toronto Hydro plans to address in the 2025-2029 rate period originally appeared in plans for relief during the 2020-2024 rate period. For the reasons summarized in Table 6 below, these investments were reprioritized, with portions of the projects completed in the 2020-2024 rate period, and remaining portions to be addressed during the 2025-2029 rate period.

[18] Exhibit 2B, Section E5.1.3.1.
[19] Exhibit 2B, Sections D2.3, D3.3.1, and C3.3

When reviewing work to be targeted within the Program, Toronto Hydro will also consider work that can potentially be deferred using Non-Wire Solutions (NWS).[20] In the case of Manby TS and Horner TS in Table 6, the short-to-medium term capacity constraints of the buses due for load transfers were mitigated by identifying opportunities where local demand response ("DR") could be leveraged to reduce peak loads. The NWS program enables efficient and cost-effective load management, and can be leveraged in the 2025-2029 rate period in the prioritization of load transfers.

Table 6: Load Transfers projects continuing from 2020-2024 to 2025-2029

Station	Bus	Reasoning
Horner	*B&Y*	Based on regular re-evaluation of the proposed work in this Program, load transfers between Fairbank TS and Runnymede TS were prioritized ahead of these stations for the 2020-2024 period. The Horner TS and Manby TS load transfers were re-prioritized, and only the portions of the load transfers that required immediate attention were addressed in the 2020-2024 rate period. The remaining transfers are scheduled to be completed in the 2025-2029 rate period.
Manby	*Q&Z, V&F*	

In order to transfer load from one station to another, Toronto Hydro often needs to install new feeders at stations with spare capacity. These stations are either existing ones with switchgear that have available capacity and feeder positions, or new stations where switchgear will be installed to create additional capacity. New civil infrastructure will be required if the existing infrastructure is in poor condition and requires rebuilding or if there are insufficient ducts to accommodate the new feeder installations. Extensive cable pulling and splices are then required to complete the transfer of customer loads from the existing feeders to the new feeders.[21] Load can also be transferred from one station to another by extending existing feeders to feeders with available capacity. In the Horseshoe distribution area, loads can alternatively be transferred by installing new switches or relocating existing switches. Therefore, the scope of work required when performing Load Transfer projects vary depending on how much upgrades are required on existing civil and electrical infrastructure as mentioned above.

[20] Exhibit 2B, Sections E7.2

[21] A splice is a joint created to maintain the connectivity between two cable sections or cable types. It is typically carried out when a longer cable is required, a branch is required or part of an old cable is replaced with a new cable.

2. Feeder Level Load Transfers and Upgrades

Asset failures (overhead conductors, underground cables, and civil infrastructure) can lead to outages that last for hours due to the time it takes for crews to switch customers from faulted feeders to standby supplies. In first contingency scenarios, the distribution system is designed to continue operating at or below rated capacity in order to facilitate the transfer of load from feeders under a faulted condition to standby feeders. This allows for the restoration of power to affected customers from the standby feeder while the faulted feeder is being repaired. If feeder capacity is constrained, the number of customers the system can be served by the standby supply may be limited. Those customers that cannot be served by the standby supply would experience lengthy service interruptions, which would adversely impact reliability. Having available capacity on additional tie feeders allows for quicker restoration during more catastrophic events where cascading load transfers are required, because more operational options will be available to restore customers.

When the load on a faulted feeder exceeds the available rated capacity of standby feeders, restoration of power to affected customers is not possible until repairs are completed and, as a result, such customers would be at risk of prolonged interruptions. For example, in the overhead system, when a feeder faults and its standby feeder ties cannot be used due to the risk of overloading, the affected customers on the faulted feeder would remain without power until the failure is completely addressed.

In addition to the expected reliability improvement, having the flexibility (in the form of switching equipment) to de-energize feeders improves Toronto Hydro’s ability to execute planned capital and maintenance work by enabling the utility to switch customers onto their standby feeders.

When processing new customer connection requests, Toronto Hydro conducts an analysis to evaluate how customers are supplied, optimize the use of existing capacity, and accommodate new customers efficiently. This analysis helps to determine areas requiring feeder level transfers to enable available capacity. In some instances, Toronto Hydro may decide to perform feeder level load transfers if the assets are already at the maximum standard cable size, or if the bus that supplies the feeder has available capacity but feeder loading is not balanced.

Performing a load transfer between feeders to accommodate a new customer is often the preferred alternative when possible as it can be carried out at a lower cost than upgrading the feeder. Similar to bus level load transfers, feeder level upgrades and load transfers provide value to current and future customers by ensuring that the system can support rapid growth in a timely and cost-efficient manner, without adversely affecting the quality of service for existing customers.

The sections that follow describe the Feeder Level Load Transfers and Upgrades planned on the 27.6 kV system, which serves the area of the system commonly known as the Horseshoe and the work planned for the 13.8 kV system, which serves the downtown core.

a. The Horseshoe System

To manage load growth in the Horseshoe area, Toronto Hydro plans to undertake capital investments in feeder level load transfers and feeder upgrades in the Scarborough, Etobicoke, and North York areas. Load transfers are preferred over feeder upgrades because the overhead system, which serves the majority of the Horseshoe area, has multiple tie switches making it easier and more cost-effective to transfer load between adjacent feeders. Cable upgrades are also performed in the Horseshoe when segments along the cable are undersized and limit the overall carrying current capability along the feeder. Such undersized segments along feeders are typically legacy aluminum cables which are upgraded to standardized copper cables to raise the maximum current carrying capacity to 600 A, which is an increase of up to 100 A in capacity, or about the equivalent of 2300 customers.[22] There are 119 Horseshoe feeders forecasted to be highly loaded by 2029 and Toronto Hydro plans to relieve 23 of the highest priority feeders (i.e. those with the highest level of overloading) through feeder transfers or cable upgrades in order to manage the forecasted growth over the 2025-2029 rate period. Toronto Hydro will continuously assess actual feeder conditions before investing in any upgrades or transfers.

b. The Downtown System

The majority of the underground 13.8 kV system in downtown Toronto is configured as a dual radial scheme. Customers are supplied by two feeders: one that provides their normal supply and the other that operates as standby supply. In areas that have experienced rapid load growth, customers now have an overloaded standby supply, with additional overloaded feeders expected during the 2025-2029 rate period. If there is a loss of supply in these areas, overloaded standby supply means that there are less options available to restore customers.

Toronto Hydro analyzed all downtown feeders to determine which feeders are projected to be highly loaded during the 2025-2029 rate period based on the Toronto Hydro's Station Load Forecast. By the

[22] Exhibit 2B, Section E7.1.

end of 2029, there is projected to be 154 highly loaded feeders in the downtown system (representing approximately 20 percent of downtown feeders) if no work is done to address them.

As a result, in the 2025-2029 rate period, Toronto Hydro plans to relieve 49 of the highest priority feeders in the downtown area to manage load growth and continuously meet system reliability goals through feeder upgrades and feeder load transfers. By comparison, in the 2020-2024 rate period, Toronto Hydro relieved 18 highly loaded feeders through cable upgrades and transfers. This increase in the number of highly loaded feeders planned for relief is due to the rapid growth of the number of highly loaded feeders. Toronto Hydro will continue to prioritize the feeder transfer and upgrade projects based on the latest information on how load is materializing on the system and regular re-forecasting efforts.

Toronto Hydro plans to upgrade undersized feeder trunks to the current standard (500 kcmil TRXLPE) to maximize previously stranded capacity for feeders that are becoming highly loaded. For example, feeder A62A supplies 16 customers in and around the downtown core along Dundas St. E. to Jarvis St., and along Yonge St. from Dundas St. to Richmond St. Many of these customers are key account customers operating commercial complexes, outdoor public and event spaces, university campus services and government locations. This feeder is at capacity due to the presence of undersized 2/0 trunk cable. An upgrade to 500 kcmil TRXLPE cable will more than double the capacity on the feeder, allowing for 5 MVA of customer load to be added.

In the downtown area, because of congested civil infrastructure nearing end of life or built to older civil standards (therefore unable to accommodate the latest cable standards), it is often necessary to rebuild or expand the existing civil infrastructure when upgrading underground cables. Figure below shows a congested legacy square duct unable to accommodate the current standard trunk cable, therefore limiting the overall capacity of feeders using this civil route. In addition to capacity constraints, the clay duct tile is typically collapsed, and in need of rebuild. Such legacy square ducts span over 4.6 kilometres and contain feeders supplying in the downtown area including hospitals, as well as other large customers.

Toronto Hydro plans to complete upgrades or rebuilds of this existing civil plant as part of this Program. It is estimated that 50 percent of the length of the civil route for each planned feeder upgrade will need to be upgraded as well to accommodate the new electrical. This includes cable chamber and duct bank rebuilds.

Figure 6: Example of a Legacy Square Clay Tile Duct

New feeder installations are also required when an area requires greater capacity than is available with existing feeders. These new feeders are then utilized to relieve the existing load and service any upcoming demand in the area. In cases where bus expansion is not possible at the station, the feasibility of expanding the bus with new feeder positions at nearby stations are explored. The new feeders from nearby stations will supply the load from the station that has reached or exceeded its capacity. One instance where new feeders from a station are required to offload a nearby station is Richview TS offloading existing feeders from Finch TS. The area which Finch TS services, spanning from Hwy 27 to Jane St, and Steeles to South of Hwy 401, have feeders that are highly loaded and require support and relief to accommodate upcoming load growth in the area. With Finch TS already highly loaded at the bus as well, new feeders from Richview TS, which is a nearby station south west of Finch TS, will support by offloading the highly loaded feeders from Finch TS.

3. Equipment Upgrades

Due to capacity constraints, Toronto Hydro is forced to impose summer switching restrictions during peak load conditions, such that certain feeders cannot be taken out of service during those periods. If restricted feeders are taken out of service, their corresponding standby infrastructure (standby feeders, adjacent network units) will be overloaded. This practice constrains Toronto Hydro's ability to complete new customer connections and hinders its ability to plan and execute other capital maintenance work in a timely and efficient manner.

Heat restricted feeders are feeders flagged as at-risk of overloading their standby feeders or network equipment during a contingency situation during peak hours or summer days. This means that these feeders should not be taken out of service (at a certain temperature) in the summer months in order to avoid overloading other infrastructure under contingency. Toronto Hydro is seeking to maintain or reduce the number of restrictions on its system so as to enhance its ability to take feeders out of service for maintenance or capital work. Cable upgrades and load transfers may be used as strategies to relieve summer switching restrictions on the primary feeder level. The equipment upgrades as part of this Program aim to upgrade undersized network units that are at-risk of overloading and may create summer switching restrictions. An example of a network unit is shown in Figure . A network unit consists of a primary switch, network transformer, and network protector.

Figure 7: An Example 500 kVA Network Unit

In the downtown core, network units are fed from various primary feeders, and are interconnected on the secondary side (i.e. low voltage) of the distribution transformer in order to provide a redundant and highly reliable supply to customers. This configuration reduces the risk of customers experiencing interruptions during single contingency events. The network system supports reliability for customers in the downtown area, highlighted as a priority through customer engagement.

Current key customers on the network system include hospitals, hotels, telecommunication and government buildings.

Through network equipment upgrades, Toronto Hydro will improve reliability for downtown customers on the network, highlighted as a priority in customer engagement. This will be done by reducing the number of potential network unit failures due to overloads; increasing the robustness of the network units by introducing the submersible design; and improving the amount of first contingency scenarios supported by reducing feeder restrictions. Network equipment that is at or over capacity must be upgraded to ensure that the network system operates without overloading. Overloading the network equipment can result in premature deterioration and failure of the assets, which in turn drives the need to impose restrictions during peak summer months. An additional benefit of upgrading existing overloaded network equipment is the introduction of a more robust submersible design that is capable of operating under flooded conditions. In locations where an upgrade is not possible because the network units are already at the highest size or if there are civil limitations, an additional transformer in a new vault may be installed or additional secondary cables may be added to support the highly loaded vaults.

In the 2020-2024 rate application, Toronto Hydro indicated its goal of reducing the number of summer switching restriction feeders to under 10, and has been doing so accordingly as seen in its progress presented in Table below.

Table 7: Summer Restrictions by Year

Summer Restrictions	Year					
	2017	**2018**	**2019**	**2020**	**2021**	**2022**
Number of Feeders Restricted	21	9	6	4	4	5

To address the growth in demand of the number of network units under contingency, Toronto Hydro plans to upgrade 5 network units during the 2025-2029 rate period.[23] Toronto Hydro's goal is to continue maintaining the total number of restrictions to below 10 by during the 2025 to 2029 rate period. To achieve this goal, Toronto Hydro will also mitigate any potential primary feeder restrictions via cable upgrades and load transfers.

[23] The peak load reading of each network unit in the system was taken over the last 5 years and a growth consistent with the Metro Toronto Regional Infrastructure Plan was added to forecast the future overloads.

Where other equipment upgrades are required due to capacity needs based on forecasted growth on the feeders and not due to asset end of life, this Program will also upgrade capacity in order to manage growth and mitigate overloading assets.

4. Civil Enhancements

When certain stations are expanded or their switchgear is upgraded, Toronto Hydro must undertake supporting civil enhancement work in the egress cable chambers to enable additional capacity at the station. Table summarizes the expected station upgrades within the 2025-2029 rate period that may require civil egress rebuilds in order to optimally serve customers. These areas are shown geographically in Figure .

Table 8: Stations Requiring Civil Egress Rebuilds

Station	Switchgear Unit	Associated Work	Target Completion Year
Bridgman TS	*A1-2H, A7-8H*	*Switchgear Renewal*[24]	2026, 2029
Danforth MS	*A1-2DA*	*Switchgear Renewal*[25]	2028
Downsview TS	*New TS*[26]	*New TS*[27]	2029+
Duplex TS	*A1-2DX*	*Switchgear Renewal*[28]	2026
Manby TS	*B-Y, V-F, T3/T4, T13/T14*	*Switchgear Renewal and Transformer Renewal*	2027, 2029
Wiltshire TS	*A5-6WA*	*Switchgear Renewal*[29]	2029
Windsor	*A5-6WR, A3-4WR*	*Switchgear Renewal*[30]	2027, 2029

[24] See Exhibit 2B, Schedule E6.6 – Stations Renewal
[25] *Supra* note 24.
[26] See Exhibit 2B, Schedule E7.4 – Stations Expansion
[27] *Ibid.*
[28] *Supra* note 24.
[29] *Ibid.*
[30] *Ibid*.

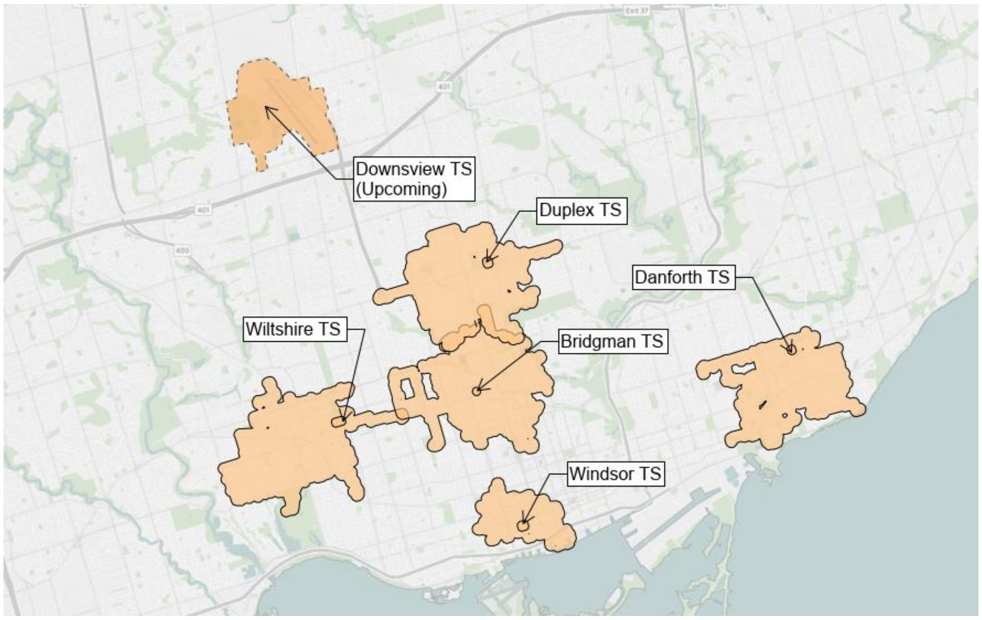


Figure 8: Stations Targeted for Civil Enhancements during the 2025-2029 Rate Period

Civil work can vary depending on the location of the asset expansion or renewal within the station, as well as the existing civil infrastructure in and around the station. For example, the Carlaw TS switchgear renewal scheduled for 2023 and 2024 will have new switchgear at the northeast corner of the station, egressing through the north cable pit. The majority of the Carlaw feeders already run north and northeast and those that are needed to the south must utilize cable chambers around the station to run south. This creates additional civil work around the station with added cable chambers and ducts being required. Another example during the 2020-2024 rate period is planned relief of Basin TS to the south to Carlaw TS due to the rapid growth around Basin TS including Ashbridge's Bay, GO Transit and the Port Lands developments. Additional feeders will need to be pulled south and the civil infrastructure must be upgraded and arranged in order to accommodate these plans.

In addition to supporting station renewal or expansion, civil infrastructure throughout the distribution system is required to be expanded or upgraded in areas that limit growth and electrical capacity. An example of infrastructure upgrade and expansion during the 2020-2024 rate period is along John Street between Front Street and Stephanie Street. The rebuilding of John Street addressed existing failing infrastructure and installed additional infrastructure required for growth. The scope consisted of rebuilding cable chambers, cable chamber roofs, vault roofs, vault rebuilds, collapsed ducts, and the expansion of ducts required for communication cables and contingency tie cables between stations. This rebuild ensured that existing key account customers fed from Windsor

TS would not be impacted by civil failure, enabled the connection of new customers in a timely manner, ensured that duct system can accommodate the fiber communication system, and enabled the ability to tie Cecil TS to Windsor TS to further mitigate against station contingency events. This was of great importance to the city because John Street connects many of Toronto's key cultural institutions to the waterfront. In the 2025-2029 rate period, Toronto Hydro is planning to invest in similar civil upgrades along Victoria Street, between Dundas Street and Lombard Street to rebuild legacy duct banks (i.e., square clay tile ducts) and undersized cable chambers that contain feeders supplying key account customers such as hospitals.

Apart from the capacity limitations, congested cable chambers increase the potential impact of chamber collapse on multiple feeders (and the significant customer load they supply in aggregate). For example, a cable chamber of 15 feeders can account for up to 75 MVA of customer load. Congested cable chambers also significantly impede the ability of crews to perform work safely.

E5.3.4 Expenditure Plan

Table 9: Historical & Forecast Program Costs ($ Millions)

	Actual		Bridge			Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Demand	24.0	29.7	30.8	22.6	13.8	50.0	56.7	42.3	38.8	48.6

Table 5: Cost Breakdown by Type of Work ($ Millions)

	Actuals			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Transfer (Bus)	8.7	13.6	15.3	16.5	4.9	34.9	30.1	20.9	16.3	7.7
Load Transfer (Feeder)	0.82	0.87	1.3	0.85	2.9	2.5	7.7	11.5	5.4	8.2
Cable Upgrades	7.3	5.9	8.3	4.7	2.4	7.6	7.1	10.0	10.0	5.0
Equipment Upgrades	0.32	0.10	0.42	0.23	0.0	0.0	0.38	0.81	0.40	0.41
Civil Enhancements	6.9	9.3	5.5	0.05	3.6	5.0	11.5	0.0	6.7	27.3

The 2025-2029 expenditure plan is based on the specific work that is planned in each year. As is true with the 2020-2024 rate period, expenditures vary considerably from one year to the next due to the volume of work associated with the different activities undertaken by the Load Demand program (i.e. load transfers, cable and equipment upgrades, and civil enhancements).

During 2020-2022, Toronto Hydro has relieved capacity constraints on the system through the:

- Alleviation of 131 MVA on highly loaded buses through bus level load transfers or bus expansion;
- Reduction in the amount of highly loaded feeders by 10 through feeder level transfers and feeder upgrades;
- Improvement to the civil infrastructure associated with station expansion of Carlaw TS, Horner TS, Runnymede TS, Strachan TS, Terauley TS, as well as the upgrade to John street civil infrastructure between Front Street and Stephanie Street; and
- Maintaining the number of summer switching feeder restrictions to under 10.

These forecasts are re-evaluated annually, as described in the DSP – Capacity Planning, driven by information on expected new connections, on expected load transfers and voltage conversions, re-evaluated growth rate, and the previous years' weather corrected peak which is used as base for load growth.[31] Based on the annual re-evaluation of station bus load forecasts, Toronto Hydro fully expects that project scheduling will change. This is natural for a program such as Load Demand. For example, Toronto Hydro planned to address 28 highly loaded feeders through cable upgrades and load transfers. However, with the changing load growth needs of the system and reprioritization, 18 highly loaded feeders have now been planned to be addressed. Instead, additional investments were allocated to bus level load transfers with the following stations undergoing transfers that were not originally planned for: Runnymede, Carlaw, Leaside, George & Duke, Dufferin, and Terauley stations. This resulted in approximately an additional 100 MVA of bus level load transfers.

Investments in the 2025-2029 rate period aim to continue to relieve capacity strained areas in the City of Toronto. The plans are based on Toronto Hydro's Station Load Forecast. As described in section E5.3.3, this Program is made up of investments in station bus load transfer, feeder level load transfers and upgrades, network equipment upgrades and civil egress enhancements.

E5.3.4.1 Station Bus Load Transfers

The proposed work aims to provide load relief to the station buses that are expected to become overloaded in the next rate period due to growth, and which are located in areas where capacity is available at an adjacent station. Some of the planned bus load transfers are dependent on the completion of station expansions projects, such as the Copeland TS Phase 2 project, which will allow

[31] Exhibit 2B, Sections D2.3, 3.2.1, and C3.3.

Toronto Hydro to provide relief to the buses at Strachan TS, Windsor TS, Terauley TS and Esplanade TS.[32]

The costs for bus level load transfers were forecasted using a cost per MVA transferred value, based on evaluations of historic project actuals. The cost per MVA can vary greatly for a bus level load transfer, depending on distance between stations involved in the transfer, location of feeders, and geographical constraints, such as the presence of bridges and highways, and civil conditions.

Load transfers in the Horseshoe area, which is generally served by the overhead system, can vary in cost depending whether the transfer requires tie switches between feeders, or whether expansion work as well is required. The cost would be considerably lower in areas where only a switch is required for a transfer compared to when expansion work would be required. Additional expansion work can include civil and electrical work in order to transfer load which can significantly increase the cost of the project.

E5.3.4.2 Feeder Level Load Transfers and Upgrades

As noted above, Toronto Hydro plans to undertake 49 feeders in the downtown area and 23 feeders in the Horseshoe area for relief through feeder upgrades and feeder load transfers during the 2025-2029 rate period.

Any cable upgrade to the trunk of a feeder is estimated to upgrade approximately 1,000 meters of cable in the downtown and 2,000 meters of cable in the Horseshoe, which will include civil upgrades for half of the distance. Civil upgrades include duct banks, cable chambers, and splices along the feeder route. The unit cost assumes 1,000 meters of upgrades per targeted downtown feeder because this is the average length of a feeder trunk, with each downtown feeder having a maximum spread of approximately 3,000 meters. In the Horseshoe, the average length of undersized aluminum cable egress that is targeted for upgrades to standardized copper cable is approximately 2,000 meters.

[32] Exhibit 2B, Section E7.4.

E5.3.4.3 Equipment Upgrades

Toronto Hydro plans to complete five network equipment upgrades during the 2025-2029 rate period in order to maintain its target of limiting summer switching restrictions under contingency scenarios to under 10.

For network equipment upgrades, the per unit cost was based on the cost to remove and install a new 750 kVA network unit, which was the most common upgrade seen in the 2020-2024 rate period.

E5.3.4.4 Civil Enhancements

Toronto Hydro plans to increase capacity and add new feeder cell positions at the following stations in the 2025-2029 rate period: Bridgman TS (downtown), Danforth TS (downtown), Downsview TS (Horseshoe), Duplex TS (downtown), Manby (Horseshoe) Wiltshire TS (downtown), and Windsor TS (downtown). Often, when station capacity is expanded and new cell positions are installed, additional feeders need new or expanded routes outside of the station via new or upgraded egress cable chambers and duct banks.

Toronto Hydro also plans to enhance its civil infrastructure in capacity constrained areas within the City of Toronto. The civil enhancement plan will address cable chambers and ducts in need of rebuild, and legacy infrastructure including square ducts which span over 4.6 kilometers, which limit the size of feeders to smaller diameter cables causing bottlenecks in capacity.

E5.3.4.5 Project Prioritization

Toronto Hydro considers a combination of several factors when prioritizing projects within the Load Demand program, including:

- **Load growth:** Toronto Hydro addresses areas of the system that are at capacity and that require significant investments to allow the connection of new customers. Forecasting of highly loaded areas is used to determine which projects should be prioritized.
- **Contingency operation:** Current limitations on the system prevent overloading during contingency operations. Projects that introduce additional capacity to allow the operators to remove these limitations will receive a higher priority.
- **Reliability:** For load transfer projects, sections of cable that require upgrading and that are on feeders with poor reliability or adjacent feeders will be given higher priority in order to improve future outage restoration times.

E5.3.4.6 Cost Management

Load Demand projects are continuously evaluated to ensure that the spending is in the appropriate areas. For example, the need for each bus level load transfer is re-evaluated annually to see if forecasts still hold true or if they should be modified. Load forecasts are the basis for determining if buses require relief. As seen in Table 6 above, two buses that were expected to be overloaded in the 2020-2024 rate period are being deferred to the 2025-2029 rate period. This allowed for other Load Demand work to be completed in their place since the transfers identified in Table 6 were no longer immediately required.

Additionally, Toronto Hydro enables cost savings through NWS. Peak shaving through Local DR can reduce immediate needs for bus level load transfers in this Program. During annual reviews of load growth forecasts, NWS may be deployed, if available, to temporarily defer bus level load transfer projects. In the 2025-2029 rate period, Toronto Hydro will aim to procure up to 30 MW of demand response capacity in the Horseshoe area, which could help defer or avoid anywhere between 23 percent to 54 percent of the total load planned to be transferred. For further details, please refer to Section E7.2 Non-Wires Solutions.

By making capacity available by both electrical relief (via bus transfers, feeder transfers, feeder upgrades and equipment upgrades), and civil relief (via station enhancements), customers are able to be connected in an efficient manner. Without available capacity, infrastructure may have to be built using a suboptimal station (i.e. not in the area of the customer(s)) and using suboptimal and lengthy routes. Avoiding this work reduces the overall cost of connecting customers.

E5.3.5 Options Analysis

E5.3.5.1 Option 1: Do Nothing

Option 1 entails not planning any load transfers, equipment upgrades, or civil enhancements. This option allows Toronto Hydro to defer capital spending. Toronto Hydro anticipates that this option would reduce reliability and increase failure risk. Increasing loading stress on existing electrical infrastructure in heavily loaded areas under first contingency would shorten the operational life time of the electrical infrastructure. Rolling blackouts may be required during the summer to ensure that the peak loading remains under the capacity for the system, since no investments are being made to resolve the overloads during summer peaks. Areas of heavy loading will continue to experience increased loading, with the capacity to transfer loads under contingency decreasing. Following this option would impair the utility's ability to expedite upgrades to relieve heavily loaded infrastructure effectively and efficiently.

The addition of new high load customers in identified heavily loaded areas may exceed first contingency capacity, making system upgrades increasingly difficult and lengthy as Toronto Hydro would be unable to take feeders out of service for planned work if there is no viable standby feeder to accept the load. Finally, the exposure risk of customers in highly loaded areas to lengthy outages due to equipment failures or severe weather will be higher because of the inability to transfer load to standby or alternate supplies if capacity constraints are violated.

This is not a feasible option as it would give rise to a risk of non-compliance with DSC sections 3.3.1 and 4.4.1, which require Toronto Hydro to prudently and efficiently manage its distribution system, and address forecast load growth.

E5.3.5.2 Option 2 (Selected Option): System Investments Aligned with Toronto Hydro's Station Load Forecast

Option 2 aligns with the Toronto Hydro's Stations Load Forecast which applies a probabilistic approach to forecast the peak loads of all the buses of the stations within the city of Toronto. The output of the forecast is arranged to reflect summer and winter peaks due to the different characteristics between the two peaking seasons. The primary drivers for load growth for the 2025-2029 rate period are Customer Connections, commercial transportation electrification, EVs and hyperscale data centres.

This investment option would relieve station capacity by transferring load away from heavily loaded areas. This option also invests in cable upgrade, feeder transfers, equipment upgrades and civil enhancements in highly loaded areas with a focus of relieve overloads under a first contingency basis. As part of this option, Toronto Hydro will also consider utilizing NWS as a mitigating tool to defer bus-level load transfers where applicable.

Efforts under this option will provide capacity to expedite future upgrades and balance system loading, makes use of existing system assets by performing load transfers between highly loaded buses and feeders to lightly loaded alternatives, and allows Toronto Hydro to maintain full compliance with sections 3.3.1 and 4.4.1 of the DSC with regard to prudent and efficient distribution system management.

This is the preferred option since it addresses the capacity needs of the distribution system that are arising in the short to medium term, as well as considering expected electrification needs that have a significant impact to Toronto Hydro's distribution system. With this option, Toronto Hydro can comply with the DSC and improve customer service, reliability, and safety of the system.

E5.3.5.3 Option 3: System Investments Aligned with Future Energy Scenarios High Electrification Scenario (Customer Transformation Low)

This option looks to invest in accordance with the Future Energy Scenarios model Consumer Transformation Low ("CT Low") Scenario which accounts for high electrification needs while assuming low efficiency.[33] Based on the CT Low scenario, the amount of bus-level load transfers will increase by 117 percent when compared to Option 2. Additionally, compared Option 2, the number of highly loaded feeders will increase by 42 percent, the number of network equipment upgrades will increase by 120 percent and the expected stations requiring additional civil egress work will increase by 50 percent. Based on these increases, this will result in an increase cost of approximately $206 million when compared to Option 2.

This option would allow for extensive relief in line with a more aggressive load growth. However, there is a higher risk of overbuilding the system if aligning with this option. While it is not recommended to proceed with this option, this analysis does provide insight into the degree of variability in load growth depending on how electrification trends and customer behaviours materialize in the 2025-2029 rate period.

E5.3.6 Execution Risks & Mitigation

Several issues can present risks to the execution of the Load Demand program.

1. **Uncertainty of Future Load Growth**

Based on studies and analysis, the Station Load Forecast considered factors with a probabilistic approach when forecasting for peak loads of all Toronto Hydro buses of the station within the City of Toronto. Potential risks could arise based on future city planning changes or changes to redevelopment areas which could impact the load growth for the area. Such uncertainties can be mitigated by monitoring trends and updating forecasting accordingly and increasing flexibility when prioritizing and deploying work under the Load Demand program. Another strategy for managing

[33] Exhibit 2B, Section D4.

unexpected growth is the use of NWS such as local DR to shave peak loads. NWS can be implemented to incentivize customers to help reduce bus peaks. This type of NWS provides temporary relief, to provide flexibility to allow the time to implement more permanent solutions such as equipment upgrades or load transfers. Therefore, capital investments will still need to be made in the Load Demand program to support this growth.

2. Increasing Complexity of Projects

In order to complete load transfers and cable upgrades, feeders may need to be pulled or upgraded over long distances, utilizing several cable chambers and duct banks along the route. Records provide an indication of what civil costs can be expected for a Load Demand project; however, there can be unexpected rebuilding or expansion of civil infrastructure that is required. Civil inspections performed earlier in the project cycle can help mitigate any unforeseen project costs. Toronto Hydro has included preliminary inspections and design during up-front project creation in order to better scope out each project, leading to less variation in scope, costs and timelines as projects progress from planning to execution and construction.

3. Challenges Coordinating with Third Party Utilities

Moratoriums and third-party construction can limit and dictate the civil routes used in load transfers. Costlier solutions to bring capacity into an area may be required because we are unable to utilize more optimal routes where moratoriums exist or third-party construction is taking place. In these cases, potential impacts must be identified at the early stages of project planning and coordination must be sought and achieved.

5.4 Metering

E5.4.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 87.4	**2025-2029 Cost ($M)**: 247.9
Segments: Revenue Metering Compliance; and Wholesale Metering Compliance	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Focus, Public Policy Responsiveness, Financial Performance, Operational Effectiveness	

The Metering program (the "Program") funds investments in the utility's metering technology to ensure the reliable measurement of electricity acquired by the utility through the provincial transmission system and distributed to its customers. The Program consists of two segments: Wholesale Meter Compliance and Revenue Meter Compliance.

The Wholesale Meter Compliance ("WMC") segment involves the planned upgrades of wholesale meters at transmission supply points.

The Revenue Meter Compliance ("RMC") segment involves the installation of meters for new customers, the replacement of meters approaching seal expiry, the planned replacement of residential and small commercial smart meters with next generation smart meters (commonly referred to as Advanced Metering Infrastructure ("AMI") 2.0, and upgrades for supporting metering infrastructure. The segment is comprised of specific initiatives that impact all of Toronto Hydro's customers. A substantial part of this segment involves the planned replacement of Toronto Hydro's population of AMI, including residential and small commercial smart meters under the AMI 2.0 deployment.

The Program and its constituent segments are a continuation of the activities described in the Metering program in Toronto Hydro's 2020-2024 rate application.[1]

The Program's primary objectives are to maintain compliance with legal and regulatory metering requirements under the *Electricity and Gas Inspection Act* ("*EGIA*"), *Weights and Measures Act*

[1] EB-2018-0165, Exhibit 2B, Section E5.4.

("*WMA*"),[2] and the *Independent Electricity System Operator's ("IESO") Market Rules* (which Toronto Hydro must abide by as a Market Participant), while facilitating accurate customer billing and supporting utility's financial obligations.[3] In addition, as summarized in Section 1.6.1.1 of Grid Modernization, the deployment of AMI 2.0 is in line with Toronto Hydro's grid modernization objectives, as it lays a strong foundation for advanced and intelligent grid infrastructure. The abundance of data that accompanies the deployment of AMI 2.0 opens up opportunities for enhanced grid observability and situational awareness. The increased granularity of data collected through advanced meters will enable more robust data analytics, unlock new possibilities for grid optimization, and promote proactive asset management, customer engagement, and the implementation of non-wire solutions ("NWS") such as flexibility services. AMI 2.0 will also play an important role in enhancing outage management and grid reliability by introducing new functionalities like "last gasp", which enables grid operators to identify outage locations and dispatch repair crews to more precise locations.

E5.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Maintaining billing accuracy of at least 98 percent by: (a) upgrading and replacing metering infrastructure and limiting the percentage of meters past their useful life and (b) completing metering system upgrade initiatives that reduce estimated bills and bill corrections; and ○ Installing ION meters for large industrial and commercial customers to enable customers to monitor energy consumption and power quality in real-time.

[2] R.S.C., 1985, c. E-4 ["*Electricity and Gas Inspection* Act"]. and R.S.C., 1985, c. W-6 ["*Weights and Measures Act*"].
[3] Independent Electricity System Operator, *IESO's Market Rules & Manuals*, Chapter 6 and Chapter 4, 6 Appendices.

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's reliability objectives by: ○ Installing meters with last gasp functionality which enables grid operators to identify outage locations and dispatch repair crews to more precise locations, which reduces operational costs and results in a quicker and more accurate response. ○ Enhancing data granularity (e.g. demand data, asset health data) which improves grid reliability by enabling the development of analytical tools that serve to proactively monitor asset health and identify maintenance needs and ultimately, reduce likelihood of unexpected equipment failure.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by: ○ Maintaining compliance with various requirements such as Measurement Canada's *Electricity and Gas Inspection Act* and Regulations, the *Weights and Measures Act,*[4] and the *IESO's Market Rules* to enable accurate and timely meter reading, billing and market settlements.[5]
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by ensuring energy consumption, and purchase of wholesale energy is measured accurately and in a timely manner. • Enhanced measurement capabilities will allow for the development of enhanced analytical insights, including new types of predictive and prescriptive analytics, providing opportunities to improve the cost-effectiveness of planning and operational decisions.

E5.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Failure Risk, Business Operations Efficiency, Reliability

[4] *Supra* note 2
[5] *Supra* note 3

E5.4.3.1 Mandated Service Obligations

Metering in Canada is governed by the *Weights and Measures Act* ("*WMA*") and the *Electricity and Gas Inspection Act* ("*EGIA*").[6] Measurement Canada has jurisdiction over the administration and enforcement of these Acts.

1. Wholesale Meter Compliance

Toronto Hydro plans to upgrade its wholesale revenue meters to comply with the metering standards mandated by *IESO's Market Rules*[7] and Measurement Canada. Wholesale revenue metering upgrades require approved instrument transformers, de-registering the existing wholesale revenue metering points, preparing the site for new compliant wholesale metering equipment, overseeing the wholesale revenue metering installation work, and completing the registration process with the IESO. In 2020, Toronto Hydro completed its Wholesale Metering conversion on its existing grid supply points to comply with *IESO's Market Rules*.[8] For the 2025-2029 rate period, Toronto Hydro plans to continue its work on all new applicable wholesale metering points.

2. Revenue Metering Compliance

The *WMA* and *EGIA* and related regulations govern Toronto Hydro's ability to bill its customers for electricity usage, and require that all meters must be resealed at specified intervals to ensure that a customer's electricity usage is metered accurately.[9] Once a seal expires, the meter cannot legally be used for billing purposes and must either have its seal period extended (via compliance testing), or be replaced.

For large homogenous batches of meters, Measurement Canada permits a sampling protocol to verify the accuracy of the meters. If the statistical accuracy results from the sample testing are within acceptable levels, all the meters in the meter group will receive a seal extension.

The regulatory framework also requires certain meters that do not fall under the sampling program to be removed for individual testing (reverification) and replaced with new meters.

[6] *Supra* note 2.
[7] *Supra* note 3
[8] *Ibid.*
[9] *Supra* note 2.

Once the seals of a meter sample group have expired, Toronto Hydro cannot use the meters in the group to bill its customers. Also, in the event that the meters with expired seals remain in use, Toronto Hydro could face financial penalties, as contemplated by *EGIA*.[10]

All categories of meters (residential, commercial and industrial, large users, suite meters, wholesale meters) will either need to have their seals extended or be replaced throughout the 2025-2029 rate period. The bulk of residential and small commercial and industrial meters (which make up the significant majority of meters in Toronto Hydro's system) will have their seals expire between 2024 and 2026. Please see Figure 1 for a breakdown of the number of meters with seals expiring by year.

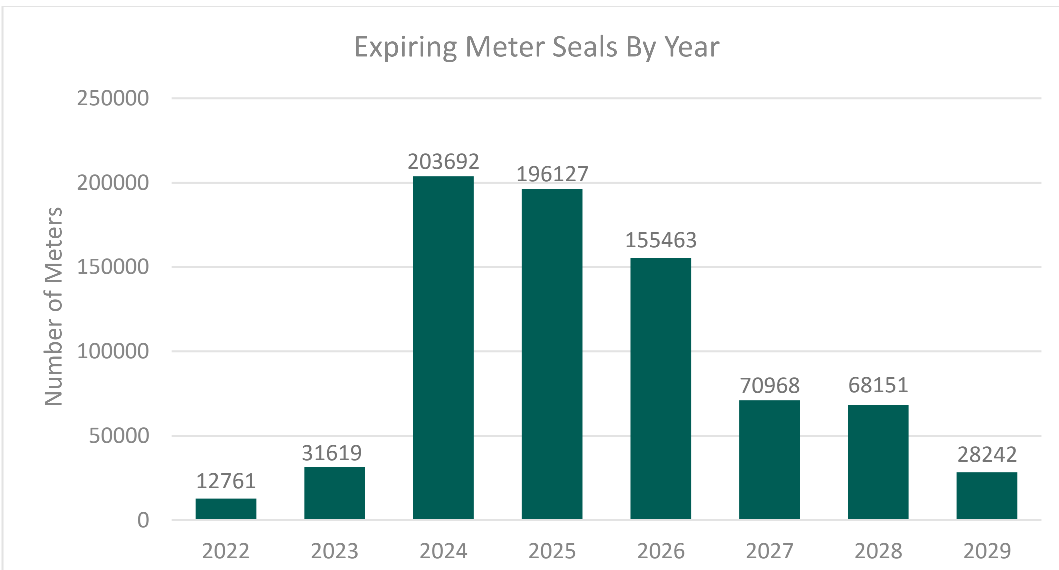


Figure 1: Expiring Meter Seals by Year

Customers in the General Service 1,000 to 4,999 kW and Large Use Customers above 5,000 kW classes represent only 0.06 percent of Toronto Hydro's customers, yet they generate approximately 12 percent of the utility's total yearly revenue. These customers are typically key contributors to the economy of Toronto and Ontario, and can have loads that are sensitive to power quality issues. Examples of such customers may include auto manufacturers, office towers, entertainment complexes that host national and international audiences and sporting events, hospitals, and industrial manufacturing plants.

[10] *Ibid.*

Replacing meters currently in use by customers in the General Service 1,000 to 4,999 kW and Large Use Customers above 5,000 kW classes at the time of meter reverification from non-ION to ION meters that have added functionality will allow for the diagnosis of customer power quality issues and may lead to a reduction in customer specific power interruptions. In addition, these meters provide three-phase power quality information that Toronto Hydro can use to investigate distribution system issues related to power quality, in order to take preventative actions to rectify system issues. These meters also provide direct benefits to the customers themselves by allowing them to monitor their energy consumption and power quality in real-time.

Figure 2: ION 8650 Meter Installed at Large User Sites

As existing meters for customers in the General Service 1,000 to 4,999 kW and Large Use Customers above 5,000 kW classes reach seal expiry, Toronto Hydro will upgrade them from non-ION meters to ION meters. Toronto Hydro must also replace and reverify these meters as their meter seals expire. The planned ION installation schedule for the 2025 to 2029 rate period is outlined in Figure 3, below.

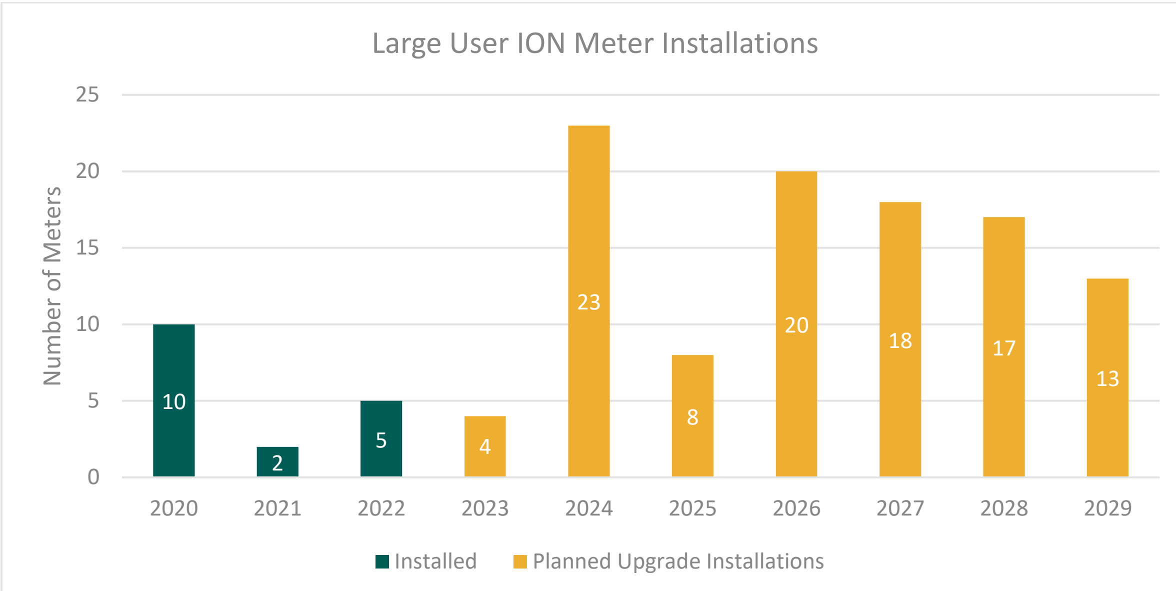


Figure 3: Large User ION Meter Installations by Year

a. <u>Suite Meter Installations</u>

Toronto Hydro is legally obligated to offer suite meter installation service. Utilities like Toronto Hydro offer this service in a competitive environment, and are also the provider of last resort in the event that the condominium chooses not to secure a third-party meter service provider.

Currently, Toronto Hydro meters approximately 94,000 individual suites using suite meters, while also metering about 3,000 multi-residential buildings using bulk meters.

Throughout the 2025-2029 rate period, Toronto Hydro will continue to offer its suite metering services to new customers and retrofit upgrades with an expected average of approximately 2,000 new units every year. Toronto Hydro will also maintain the existing population of installed suite meters by reverifying and re-sealing the meters, as required.

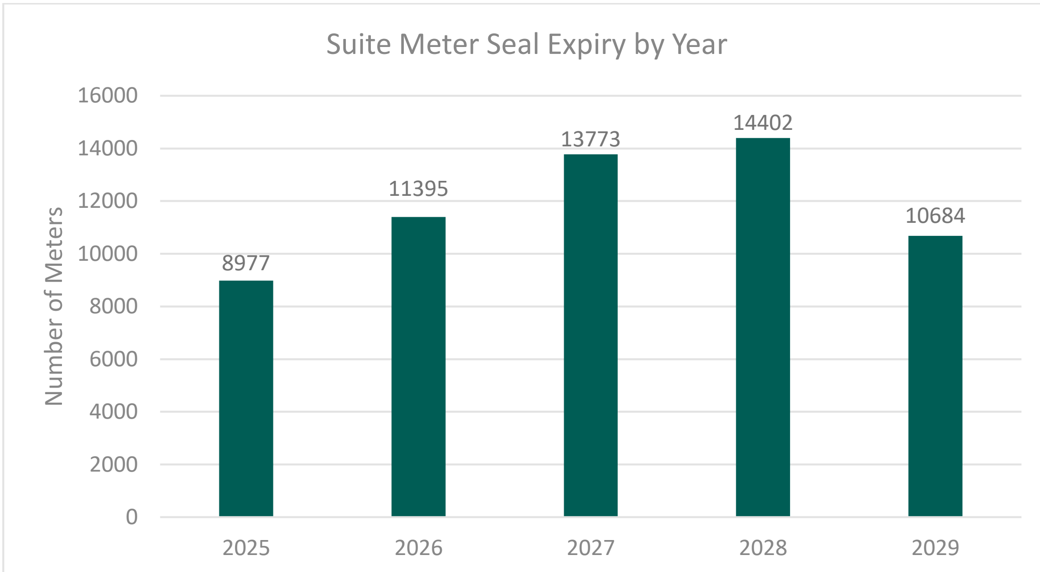


Figure 4: Suite Meter Seal Expiry by Year 2025-2029

b. <u>Continued Provincial Meter Data Management Repository ("MDM/R") Integration</u>

Toronto Hydro's billing systems were fully integrated with the provincial Meter Data Management Repository *("*MDM/R") by the end of 2018. During the 2025-2029 rate period, Toronto Hydro expects the IESO, in its capacity as the Smart Metering Entity ("SME"), to perform upgrades and annual enhancements to the MDM/R. For example, following recent amendments to Ontario Regulation 393/07, distributors will be required to transmit smart metering data relating to electricity conveyed into the distribution system as of January 1, 2025, which may drive further system modifications.[11] Toronto Hydro will need to ensure that its internal metering systems and Customer Care and Billing System ("CC&B") continue to communicate successfully and uninterruptedly with the MDM/R.

E5.4.3.2 Growth in Interval Meters

Efficient metering system is essential to manage Toronto Hydro's billing data in order to meet Ontario Energy Board ("OEB")'s prescribed billing accuracy targets and applicable metering requirements as per the Distribution System Code ("DSC"),[12] and ensure continuous vendor support.

[11] Ontario Regulation 393/07: Smart Metering Entity, made under *Electricity Act, 1998,* SO 1998, Ch 15, Sched A.
[12] Ontario Energy Board, *Distribution System Code* (August 2, 2023).

As the industry shifts towards electrification and decarbonization, the rise in the adoption of electric vehicles ("EVs") and distributed energy resources ("DERs") will increase customers' and stakeholders' expectations with respect to access to precise, hourly interval metering data to enable demand management, participation in the Industrial Conservation Initiative, and similar activities.[13] To facilitate this transition, Toronto Hydro will need to ensure it has adequate capacity to respond to the higher volumes of new metering installations and continue to comply with the applicable metering requirements as per *WMA*, *EGIA*,[14] and DSC in the 2025-2029 rate period.[15]

E5.4.3.3 Failure Risk

Toronto Hydro was among the first utilities to implement smart meters in support of provincial policy objectives, installing the bulk of its residential and small commercial meters between 2006 and 2008. As the meter population ages, the probability of meter failures increases. The rate of increase in failure risk accelerates as meters approach and surpass their expected lifespan, which is typically 15 years.[16] In 2021, segments of Toronto Hydro's meter population began to surpass the 15-year lifespan. By 2025, approximately 70 percent of Toronto Hydro's residential and small commercial meters will have surpassed their expected useful life as shown in Figure 5 below. Without proactive intervention, Toronto Hydro expects this trend to lead to accelerating rates of meter failure.

[13] Under the *Industrial Conservation Initiative*, Class A consumers can reduce the Global Adjustment portion of their bill if they are able to reduce or avoid consuming electricity from the provincial electricity grid during the top coincident peak hours of the year.
[14] *Supra* note 2.
[15] *Supra* note 11.
[16] Exhibit 2A, Tab 2, Schedule 1, Appendix D.

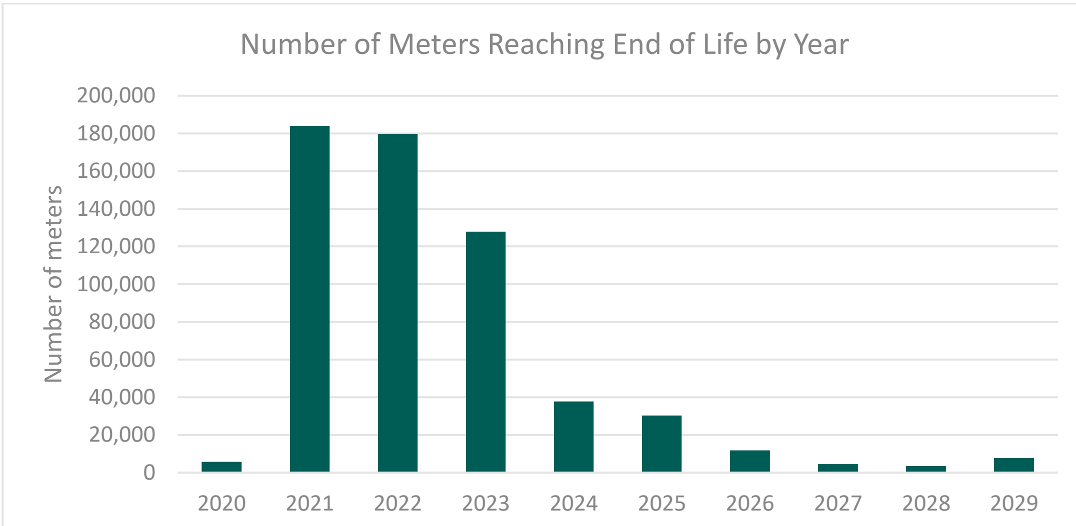


Figure 5: Residential and General Service <50 kW meters reaching end of life at 15-year lifespan

Failed meters have several negative consequences for utility operations and outcomes. When a meter fails, Toronto Hydro must estimate the customer's bill. Estimated billing decreases performance on OEB-prescribed billing accuracy targets, decreases customer satisfaction due to subsequent billing corrections, and undermines the utility's financial stability. Furthermore, replacing meters reactively is generally less cost-effective than doing so as part of a higher-volume planned program.

To address the growing population-wide risk of failure, Toronto Hydro intends to replace approximately 680,000 meters between 2023 to 2028. Meters will be replaced at or shortly following the end of their useful life of 15 years. In the process of renewing this significant population of end-of-life meters, the utility plans to introduce next generation smart meters and supporting network infrastructure, which – as discussed in the following section – will allow Toronto Hydro to increase the customer value derived from these assets through expanded capabilities.

E5.4.3.4 Business Operations Efficiency & Reliability

1. AMI 2.0

Metering technology plays a vital role in facilitating the efficient and effective operations of Toronto Hydro's system. A significant portion of Toronto Hydro's residential and small commercial meters were installed between 2006 and 2008, and rapid advancements in technology have rendered these first-generation smart meters outdated and obsolete. While the replacement of these meters is primarily driven by failure risk, advancements in metering technology have allowed for the adoption of incremental functionalities that directly align with Toronto Hydro's Grid Modernization strategy.

As shown in Figure 6, below, Toronto Hydro expects AMI 2.0 to deliver new capabilities beyond AMI 1.0, which was predominantly focused on meter-to-cash efficiencies. These new benefits include improved billing accuracy, faster outage response, improved network range, enhanced security against cyber-threats, increased grid transparency (e.g. system observability), and improved data granularity and analytical capabilities. In the longer term, Toronto Hydro intends to leverage the monitoring and control capabilities associated with AMI 2.0 to develop additional functionalities that could prove valuable in the management of an electrified and decarbonized energy system, including load disaggregation (e.g. tracking consumption by type of home appliance) and the potential integration of smart meters within the utility's DER management system ("DERMS" or "Energy Centre"). These evolving features are dependent on further technological developments.

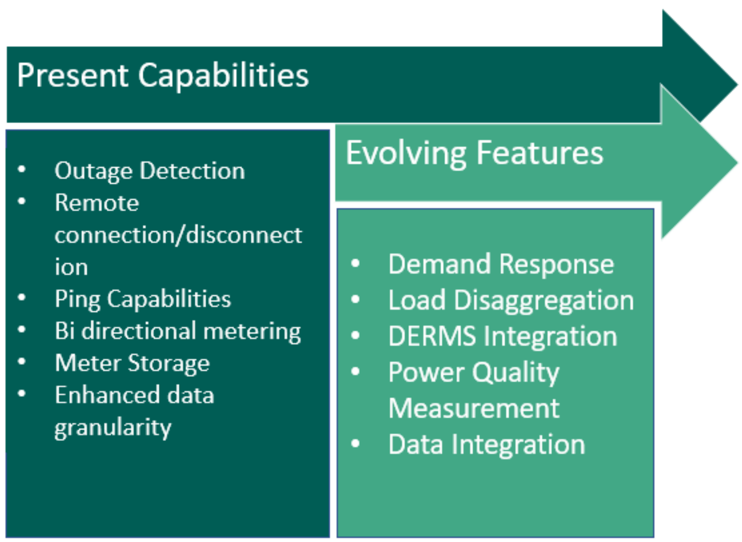


Figure 6: AMI 2.0 Use Cases: Expanded Capabilities

For a comprehensive overview of the role and expected benefits of AMI 2.0 in Toronto Hydro's modernization strategy, please refer to Section 1.6.1.1 of *Grid Modernization*. Three of the primary "out of the box" capabilities – last gasp, improved transmitting, and remote disconnect and reconnect – are highlighted below.

a. *Last Gasp Functionality*

Currently, Toronto Hydro is typically dependent on phone or service calls to define the location and boundaries of an outage. The utility's next generation smart meters will enable automatic outage and restoration notification (called "last gasp"). This capability will serve to reduce outage response times by deploying crews to the specified location sooner. See Figure 7, below, for a depiction of the operation of the "Last Gasp" functionality.

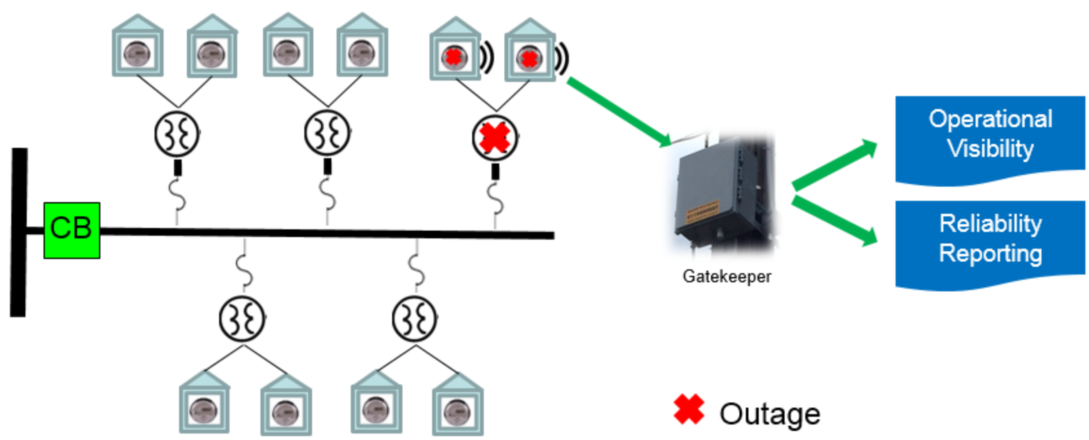


Figure 7: Last Gasp Function

b. *Improved Transmitting*

Another key feature of next generation meters is the presence of a more effective transmitter that will drastically increase the range and penetration of the meter signal. This is expected to increase the number of meters successfully read, reducing "orphaned" meters and the number of manual reads required, and further reducing the number of estimated bills issued, increasing Toronto Hydro's performance on OEB's bill accuracy metrics.

c. *Remote Connection/Disconnection*

Additionally, the introduction of meters with remote connection and disconnection capabilities allows Toronto Hydro to reduce the cost of performing disconnections and reconnections, due to the reduced need to dispatch field crew to a customer's property. This feature also enables customers to be reconnected soon after receiving payment, and allows for a more efficient and flexible implementation of OEB-prescribed reconnection standards. Toronto Hydro already completes all reconnections within two business days at least 90 percent of the time, as required by the OEB.[17] However, remote reconnection technology will significantly reduce reconnection timelines, which is more convenient to customers, therefore improving customer satisfaction.

2. Interval Metering system

Currently, Toronto Hydro uses the Interval Metering system, ITRON Enterprise Edition ("IEE" - the data processing system) and MV-90 (data collection system) to ensure efficient metering and support the interval data collection process for Toronto Hydro's interval metered customers (i.e. General Service at least 50 kW and above customers), respectively. Efficient metering is essential to manage Toronto Hydro's billing data in order to meet OEB prescribed billing accuracy targets and applicable metering requirements as per the DSC, and ensure continuous vendor support.

The utility will upgrade both systems to maintain vendor support. The IEE system is scheduled for an upgrade during 2023-2025 and again during 2028-2029. The MV-90 data collection system is also scheduled for upgrades during 2026-2027 to support better design, functionality and enhance the interval data collection process.

3. Residential Metering

Currently, Toronto Hydro's residential metering head-end system ("Connexo") is responsible for collecting and submitting measurement data and meter events to the meter data management ("MDM") systems. This system consists of two components, Connexo NetSense and Connexo FieldSense. Connexo FieldSense was implemented in 2022 and incorporates the software and hardware for field service management. The utility must continually upgrade its residential metering head-end system to maintain vendor support and the capability to enable features available on newer generation meters. By end of 2023, Toronto Hydro plans to implement a new version of Connexo NetSense, the residential metering head-end system which will be required to support the next generation meters (AMI 2.0). This upgraded version will allow for improved functionality – enabling enhanced communication features available in newer advanced meters and implementing a Gatekeeper (Collector) replacement program. More importantly, the new generation of meters will reduce the number of manual meter reads and estimated bills. This will also allow Toronto Hydro to

[17] *Supra* note 11, Section 7.10.1.

continue to meet OEB-prescribed bill accuracy targets and improve customer satisfaction by limiting billing errors.

4. Suite Metering

The City of Toronto is experiencing significant development of condominiums and other high-density buildings. As a result of this customer growth, by the 2025-2029 rate period Toronto Hydro's current suite meter AMI system ("Primeread") will no longer be able to retrieve and process the suite meter data fast enough on a daily basis to meet meter reading and billing performance targets mandated by Measurement Canada and the IESO. As a result, Toronto Hydro intends to upgrade its data collection system, Suite Meter Advanced Metering Infrastructure ("AMI") to i) ensure continuous vendor support, ii) improve Toronto Hydro's operations, including timely and accurate billing resulting in higher customer satisfaction, ability to meet OEB-prescribed bill accuracy metric (by reducing estimated billing and manual reads); and iii) improve financial stability. The lifecycle of the Suite Metering AMI has a scheduled upgrade roughly every three years to keep up with the influx of new suite metered customers. Primeread was initially brought online in 2012, the first upgrade took place in 2015, followed by 2017. The next upgrade is scheduled in 2023 and then again during 2027-2028.

5. Operational Data Storage Upgrade ("ODS")

Presently, ODS is used for framing consumption data for billing and for automated validation, editing and estimating meter data. ODS transfers consumption data from meters into Toronto Hydro's CC&B for billing and ensures timely and accurate billing for customers. The transfer of consumption data from ODS to CC&B is crucial to complete the annual rate reclassification process, as mandated by OEB Distribution System Code. The upgrade scheduled for 2024-2026 will enhance the ODS to better manage Toronto Hydro's billing data to meet OEB prescribed billing accuracy targets and ensure continuous vendor support. The subsequent upgrade for ODS is scheduled for 2029. These upgrades would also accommodate any new price plan introduced by OEB.

E5.4.4 Expenditure Plan

Toronto Hydro's historic and forecast spending in the Program is shown in Table 4, below. Expenditures in the Program are largely driven by the timing of metering and metering system upgrade cycles.

Table 4: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Metering	11.2	8.1	8.4	9.0	50.7	63.7	69.9	72.4	34.7	7.4

The majority of costs in 2020 is attributed to work related to wholesale metering compliance. The bulk of spending over 2021-2023 has been driven by upgrades to meter data and related field services systems to retain vendor support, meter replacements and reverification related to revenue metering compliance, and suite metering costs. To address funding constraints over the 2020-2024 rate period, Toronto Hydro deferred the majority of meter replacements to the 2025-2029 rate period, when it plans to replace meters at their seal expiry year. In addition, delays in procuring AMI 2.0 meters required the utility to adjust the pace of replacements through its sampling and reverification program by extending the seal life for meters with seals expiring in 2023 by six years. During the 2020-2024 rate period, Toronto Hydro plans to replace approximately 50,000 residential, small commercial, and industrial meters, as part of the AMI 2.0 project. Starting in 2024, program costs are forecasted to increase, primarily driven by the resumption of deferred meter replacements for residential, small commercial, and industrial meters, including the installation of next generation meters as part of AMI 2.0. During the 2025-2029 period, Toronto Hydro plans to replace approximately 630,000 meters.

Although the replacement of these meters is primarily driven by failure risk, the advancements in technology have allowed for the adoption of advanced functionalities. These meters will allow Toronto Hydro to expand the functionality of its metering population, through wider interoperability using a standards-based solution, greater options for remote meter disconnect and reconnect, distributed intelligence, cloud and data analytics, advanced outage detection, integrated distribution automation network support, remote power quality monitoring, and personalized customer communication.

Table 5, below shows the detailed breakdown of Program spending over the 2020-2024 rate period.

Table 5: Actual & Bridge Program Costs 2020-2024 ($ Millions)

	2020	2021	2022	2023	2024	Total
Residential and Small C&I Meter Replacement	0.44	0.05	1.74	3.39	43.63	**49.24**
Suite Metering	1.84	1.80	1.02	1.21	1.19	**7.06**
Large Customer and Interval Metering	0.12	0.02	0.03	0.05	0.34	**0.55**
Remote Disconnect	0.78	0.76	0.33	0.31	0.31	**2.50**
Sampling/Meter Replacement	4.19	3.58	2.88	1.53	2.92	**15.10**
Wholesale Metering	1.66	-0.02	0.14	0.30	0.70	**2.79**
System Upgrades	2.19	1.89	2.31	2.20	1.60	**10.19**
Total	**11.2**	**8.1**	**8.4**	**9.0**	**50.7**	**87.4**

Table 6, below, provides a breakdown of Toronto Hydro's forecast expenditures over the 2025-2029 rate period. This forecast is based on the number of meters that will need to be resealed or replaced in each year to ensure compliance with Measurement Canada and *EGIA* requirements.[18] In addition, Toronto Hydro must continuously monitor and manage the risk of asset failures associated with meters past their end-of-life by replacing meters at or shortly following their useful life of 15 years with next generation smart meters and supporting network infrastructure, as part of AMI 2.0. Lastly, the forecasted plan allows Toronto Hydro to increase the customer value derived from these assets through expanded capabilities that can be leveraged to meet future changes in customers' needs and preferences. Costs for metering system upgrade initiatives are based on a paced installation schedule using currently available cost estimates.

As shown below, the greatest increase in Toronto Hydro's forecast spending over the 2025-2029 rate period compared to historical spending over the 2020-2024 rate period is seen in the residential and small commercial meter replacement category. This increase is primarily attributed to the meter replacement initiative under the AMI 2.0 deployment (See Options Analysis section for additional details). With respect to suite metering, although the total cost is decreasing over the five-year period, the total cost is higher than for the 2020-2024 rate period to support the expected average growth of approximately 2,000 new units every year. With respect to Wholesale Metering, initially, the wholesale metering upgrade at Charles TS was scheduled within the 2020-2024 rate period. However, based on a cost benefit analysis, Toronto Hydro made the decision to move this upgrade

[18] *Supra* note 2

to the 2025-2029 rate period, as part of the scope of Hydro One's planned power transformer replacements.

Table 6: Forecast Program Costs 2025-2029 ($ Millions)

	2025	2026	2027	2028	2029	Total
Residential and Small C&I Meter Replacement	54.5	58.9	62.2	26.0	0.0	**201.6**
Suite Metering	2.1	1.9	1.8	1.7	1.6	**9.1**
Large Customer and Interval Metering	0.2	0.7	0.3	0.3	0.2	**1.7**
Sampling/Meter Replacement	4.9	4.2	5.0	3.9	3.2	**21.2**
Wholesale Metering	0.0	1.5	0.0	0.0	0.0	**1.5**
System Upgrades	2.0	2.6	3.0	2.9	2.4	**12.8**
Total	**63.7**	**69.9**	**72.4**	**34.7**	**7.4**	**248.1**

E5.4.5 Options Analysis

E5.4.5.1 Options for Revenue Meter Compliance

The Revenue Meter Compliance segment includes many tasks that must be completed in order to remain in compliance with Measurement Canada requirements. This includes the meter replacements for residential, suite meters, interval meters, and large users and metering system upgrades. These projects must be completed to ensure continued compliance with Measurement Canada and OEB requirements. For example, for the interval and suite metering projects, Toronto Hydro must maintain the meter seals to ensure continued compliance with requirements contained in the *WMA* and the *EGIA*.[19]

The major project for the Revenue Meter Compliance segment over the 2025-2029 rate period is the residential and small commercial meter replacement under the AMI 2.0 deployment. The AMI 2.0 project is slated to commence in the 2020-2024 rate period, and will continue throughout the 2025-2029 rate period. The options for the 2025-2029 rate period revolve primarily around the pace of meter replacements under the AMI 2.0 project, and only consider the costs associated with residential and small commercial meter replacement. If meters with expired seals are not replaced before their seal expiry, their seals will be extended through the sampling and reverification program under each option. This project has four options for completion, which are discussed in detail below.

[19] *Supra* note 2.

1. Option 1: Replacement of meters beyond their 15-year useful life

This option replaces meters in their second seal period, which is generally beyond their 15-year useful life. This option is the least capital intensive of the four, as it defers the meter replacement to a future period. Although this option is the most financially feasible, meters would remain in operation for the longest period of time, and beyond the useful life, posing considerable operational, regulatory and financial risks. As well, this option does not replace the entire population of AMI-included models by the end of 2029.

As most of the meters are replaced past their end of useful life under this option, it poses a risk of failure for these aging meters. Substantial meter failures would have a significant negative impact on Toronto Hydro's operations, including lack of timely and accurate billing resulting in lower customer satisfaction, inability to meet OEB-prescribed bill accuracy metric and financial instability. A reactive approach to replace the meters that have failed would result in an increase in Toronto Hydro's operational costs which would need to be addressed through the redirection process, thereby placing other forecasted investments at risk.

The total cost of this option for the 2025-2029 rate period is $163.0 million.

2. Option 2: Replacement of meters beyond their 15-year useful life while mitigating risk of asset failure

Option 2 has a greater emphasis on mitigating the risk of asset failures associated with meters past their end-of-life. Under Option 2, meters would be replaced earlier than Option 1, resulting in the replacement of more meters in the 2025-2029 rate period than under Option 1. Under Option 2, however, a portion of the original AMI meters would remain in the field delaying the achievement of Last Gasp functionality. Last Gasp functionality cannot be enabled until the majority of meters are replaced with newer models. Also, Toronto Hydro will not be able to capture the entire benefits of AMI 2.0 meters until the majority of the current meters are replaced.

The total cost of this option for the 2025-2029 rate period is $182.7 million.

3. Option 3: Replacement of meters as they reach seal expiry

The primary focus of this option is to replace meters as they reach seal expiry, regardless of their age or seal period. This option will pose a greater risk for resource balancing as it requires a large number of meters to be replaced in 2025.

As this option does not prioritise meter replacements based on meters past their end-of-life, this will pose a greater risk of failure for meters past end-of-life which may result in additional operational cost for field activities and manual billing of the customer. A reactive or ad hoc approach to meter replacement also requires more operational costs, compared to a planned replacement.

The total cost of this option for the 2025-2029 rate period is $199.0 million.

4. Option 4: Replacement of the entire fleet of meters (Preferred Option)

Under option 4, the entire fleet of AMI meters would be replaced during over 2023-2029. The replacement schedule would be identical to Option 2 for meters that have reached their end-of-life by 2029 plus those that have an end-of-life beyond 2029 would be added in.

This pacing option adequately achieves all of the intended objectives of the replacement such as the seal expiry issue and potential risk of meter failure beyond end-of-life, while mitigating any operational, regulatory and financial risks. This option also aligns with Toronto Hydro's grid modernization and customer experience strategic objectives as it enables the earliest attainment of out-of-the-box benefits compared to all other options. Benefits include remote disconnect and reconnect and the earliest achievement of Last Gasp functionality. Option 4 also lays the groundwork for the implementation of other advanced capabilities that will require further investments in technology (e.g. DERMS), development of organizational capabilities (e.g. advanced analytics and data governance) and alignment across multiple organizational stakeholders to be realized (See Figure 6 above – AMI 2.0 Use Cases: Expanded Capabilities for more details).

Given these considerations, Toronto Hydro has selected Option 4 as its approach.

The total cost of this option for the 2025-2029 rate period is $201.6 million.

5. Options Comparison

Option 4 is selected based on the following criteria as summarized in Table 7:

- **Lowest number of projected meter failures associated with assets past end-of-life**: The proposed replacement strategy in Option 4 and Option 2 is expected to have the lowest number of meters past their life expectancy in the 2025-2029 rate period. Delaying the replacement of meters beyond their useful life of 15 years can lead to an increased risk of meters failure. As a result, there is an increased risk of non-compliance with the *EGIA*,[20] the OEB-prescribed performance metric pertaining to bill accuracy and *IESO's Market Rules* regarding market settlements.[21] In addition, responding to meter failures that occur before their scheduled replacement can result in increased operational costs (e.g. billing exceptions that require manual intervention and additional field activities to investigate the failures). Additionally, a reactive or ad hoc approach to replacing meters that have failed can result in higher operational costs that would need to be redirected, placing other forecasted investments at risk.

- **Earliest achievement of Last Gasp functionality**: Next generation meters are equipped with this capability. This feature enables grid operators to identify outage locations and dispatch repair crews to more precise location, resulting quicker and more accurate response. It also enables emergency response and outage restoration activities that require customer level outage information. It is expected that this option will provide the fastest achievement of Last gasp capability.
- **Replacing entire fleet of meter models included in the AMI 2.0 project**: By replacing the entire fleet of AMI 2.0-included models, this option is expected to lay the groundwork to realize future advanced capabilities of AMI 2.0 meters. These advanced capabilities will serve to equip Toronto Hydro and its customers with new functionalities that are well-aligned with Toronto Hydro's Grid Modernization and Customer Experience objective and lay the foundation for the development of an intelligent grid (i.e. two-way interactive capabilities) and enhancing customer service (i.e. omni-channel view of the customer). The advanced capabilities of the AMI 2.0 meters will require further investment in technology (such as DERMS), development of organizational capabilities (such as advanced analytics and data governance) and alignment across multiple organizational stakeholders to be realized. (See above Figure 6 –AMI 2.0 Use Cases: Expanded Capabilities).

[20] *Supra* note 2.
[21] *Supra* note 3.

Table 7: Options Comparison

Option	Emphasis	Risk of asset failures past EOL	Investment Level	Replacing all AMI2.0 models by 2029
Replacement of meters beyond their 15-yr useful life	Minimize capital investment in the 2025-2029 period	Medium	Lowest	No
Replacement of meters beyond their 15-yr useful life while mitigating risk of asset failure	Minimize meters past EOL	Low	Medium	No
Replacement of meters as they reach seal expiry	Align replacement with seal expiry	High	High	Yes
Replacement of the entire fleet of meters (Preferred Option)	Minimize meters past EOL	Low	High	Yes

E5.4.5.2 Options for Wholesale Metering Compliance

For the Wholesale Metering Compliance segment, Toronto does not have any alternative options as the utility is required to complete the remaining Meter Service Provider ("MSP") conversions, in accordance with IESO's mandated requirements.

Toronto Hydro seeks new opportunities, through close collaboration with Hydro One Networks Inc., to 'bundle' any proposed Wholesale Metering Compliance initiatives with planned capital improvements. This includes replacements of any Hydro One power transformers and distribution equipment within the joint-use terminal stations.

E5.4.6 Execution Risks & Mitigation

The table below illustrates the major program risks that may occur while executing the Program.

Table 8: Meter Risks, Impact, Probability, and Mitigation

Project Segment	Risk	Impact	Probability	Mitigation
Revenue Meter Compliance	Execution/ Supply chain Risk for AMI 2.0 deployment	The Mass deployment plan for AMI 2.0 meters would have to be modified and timelines stretched. This would force Toronto Hydro to reseal meters past useful life, increasing capital expenditures and risk of failure	Low	• Ensure that enough lead time is provided to the vendor to ensure delivery of equipment as required. • Toronto Hydro will adopt the following mitigation measures to ensure contractual mechanisms are available as well as to oversee and enforce contract terms and conditions: ○ Clearly state expected timelines and have resolution clauses to address delays. ○ Identify an escalation path to quickly resolve conflicts and discrepancies. ○ Enforce short interval control through vendor project status updates and reports.
Wholesale Metering	Hydro One projects enabling Toronto Hydro's required meter replacements are delayed.	Compliance with *IESO Market Rules* is affected or delayed.	Low – projects are complicated and subject to equipment delays and resource availability.	Work closely with Hydro One to schedule work and to allocate appropriate resources to metering compliance projects.

E5.5 Generation Protection, Monitoring, and Control

E5.5.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 11.2	**2025-2029 Cost ($M):** 35.0
Segments: Generation Protection, Monitoring, and Control	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Focus, Public Policy Responsiveness, Operational Effectiveness - Safety, Operational Effectiveness - Reliability	

The Generation Protection, Monitoring, and Control program (the "Program") allows Toronto Hydro to fulfill its regulatory obligations under section 6.2.4 of the Distribution System Code ("DSC") and section 25.36 of the *Electricity Act, 1998* to connect Distributed Energy Resource ("DER") projects to its distribution system, which includes renewables like solar photovoltaic, wind and biogas.[1] It also allows Toronto Hydro to meet its obligations under section 6.1 of its Distribution License and section 26 of the *Electricity Act, 1998* to provide generators with non-discriminatory access to its distribution system. Toronto Hydro's investments in this Program consist of "renewable-enabling improvements".[2]

As of 2022, Toronto Hydro has connected 2,421 DERs totalling 304.9 MW in capacity. The utility is forecasting an increase in DER connections (including energy storage), reaching an estimated 516.7 MW by the end of 2029. To safely connect and monitor these DERs, Toronto Hydro plans to make the following investments in the 2025-2029 rate period:

- Generation protection measures, including the installation of bus-tie reactors at six station busses to alleviate short circuit capacity constraints; and
- Installation of 315 monitoring and control systems ("MCS") for renewable DER facilities greater than 50 kW to provide situational awareness and control of DER facilities on the distribution system.

[1] SO 1998, Ch 15 Sched A.
[2] Sections 1.2 and 3.3.2 of the DSC.

E5.5.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Customer Focus	• Contributes to Customer Service objectives by: ○ Enabling the connection of new generation customers without extensive delays or adverse impacts to existing and new customers; ○ Complying with sections 25.36, 25.37 and section 26 of the *Electricity Act, 1998* by connecting DER customers to its distribution system; ○ Providing Toronto Hydro with the ability to observe larger DERs in real-time and enable the maximum allowable amount of generation to be connected to the grid.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Ensuring the operation of the distribution system remains within safe and allowable designed short circuit current limits by installing six bus-tie reactors on station buses; ○ Avoiding unintentional islanding and reducing the islanding risk of DER sources; and ○ Ensuring bi-directional flows remain within distribution system design parameters including thermal and short-circuit capability by installing MCSs at existing and new DER facilities.
Operational Effectiveness - Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency (TRIF) measure and employee safety by: ○ Enabling automatic disconnection of DER from the grid in adherence to OESC Rule 84-008 ○ Provide the ability to both remotely and automatically isolate DER connections under specified conditions as part of work protection and EUSR rule requirements
Public Policy Responsiveness	• Supports the Ministerial directive to facilitate innovation and support DER integration within Ontario's electricity system

E5.5.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Reliability, Customer Service Requests

Toronto Hydro is legally mandated to connect DER customers and provide generators non-discriminatory access to its distribution system.[3] The planned investments in this program qualify as Renewable Enabling Improvements in the DSC and will address certain barriers to connecting DERs, including short-circuit capacity constraints, increased risks of islanding, overloading the system and increased thermal ratings. Furthermore, by investing in real-time monitoring and control at customer DER sites, Toronto Hydro is continuing to lay the foundation for more advanced DER management use cases in the longer-term.

The Program is fundamentally customer-driven. The proposed work will allow Toronto Hydro to connect customer DER projects to the distribution system through the Customer and Generation Connections program.

The planned investments are also critical renewable enabling improvements that Toronto Hydro must carry-out in order to safely and reliably respond to the increasing demand of renewable DER facilities across the City of Toronto.

Figure 1 below shows typical DER installations on the Toronto Hydro distribution system, as enabled by investments in this Program.

Figure 1: Residential (left) and Commercial (right) DER Installation

[3] See: Sections 25.36, 25.37 and 26 of the Electricity Act, 1998; Section 6.2.4 of the Distribution System Code; Section 6.1 of Toronto Hydro's Distribution License.

E5.5.3.1 Proliferation of Distributed Energy Resource Facilities

As of 2022, Toronto Hydro has connected 2,421 DERs totalling 304.9 MW in capacity. The utility is forecasting a continued increase in DER connections (including energy storage), reaching an estimated 516.7 MW by the end of 2029.[4]

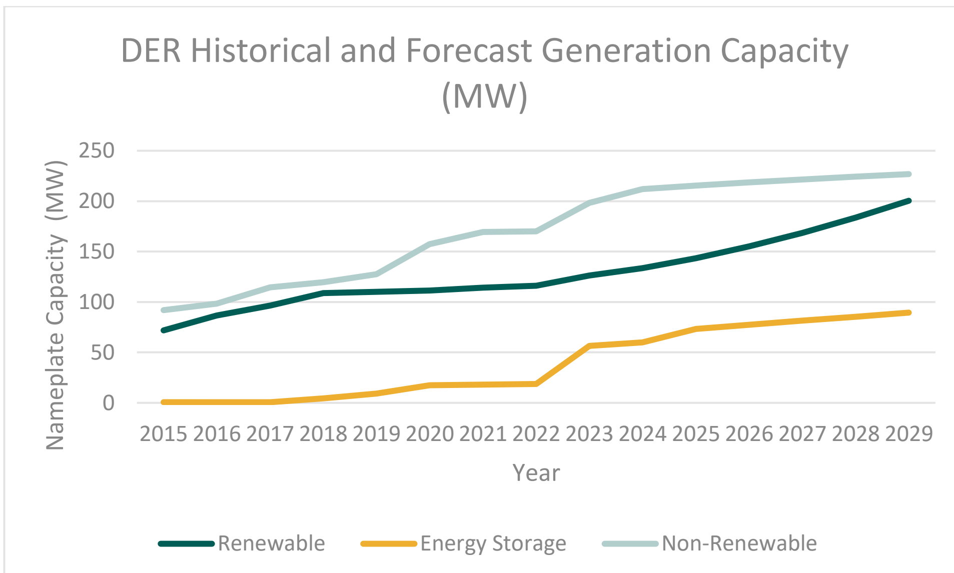


Figure 2: Historic and Forecasted Generation Capacity 2015-2029

As discussed in detail in the Generation Connection segment at section E5.1.3.2, this forecast is subject to uncertainty. As a customer-driven program, the uptake of DERs is affected by customer behaviour and other external factors, including policy and technology developments. For example, the cancellation of the Feed-in-Tariff ("FIT") program in 2018 resulted in a sharp decrease in renewable DER applications after a period of high year-over-year increases. Between 2009 to 2018, Toronto Hydro saw a compound annual growth rate of 33.93 percent, peaking in 2011 with a more than 89.9 percent increase in generation installed compared to 2010. From 2019 to 2022 the compound annual growth rate fell to 1.84 percent.

Looking ahead, the results of Toronto Hydro's Future Energy Scenarios modelling effort depict a wide range of DER uptake scenarios for the next decade and beyond. For example, at the very high end, the Future Energy Scenarios model shows that achieving Net Zero by 2040 in accordance with the City of Toronto's current strategy could involve increasing renewable penetration on Toronto

[4] See EB-2023-0195, Exhibit 2B, Sections E3 and E5.1 for a discussion of the DER forecasting methodology.

Hydro's grid to an estimated 1,249 MW by 2029. This would represent an increase of 974.9 percent of DER capacity on the grid. Hosting this level of DERs while also facilitating the full realization of coordinated DER benefits for the grid could require significant investment in hosting capacity expansion, grid modernization, and innovation.

In order to manage the inherent uncertainty of forecasting these connections, Toronto Hydro regularly reviews DER connection trends to evaluate where system constraints will emerge.

E5.5.3.2 System Capability to Connect and Control Distributed Generation

Toronto Hydro supports connecting DERs to the distribution system in alignment with the DSC and in coordination with Hydro One and the Independent Electricity System Operator ("IESO"). The utility has identified a number of constraints within its system that impact DER connections and interconnection-related decisions: 1) short-circuit capacity; 2) risk of islanding; 3) thermal limits; and 4) the lack of the ability to transfer loads between feeders during planned work.

Asset failure can occur when distribution equipment exceeds system short circuit levels, equipment thermal ratings and nominal voltage ratings. Failures due to distribution system stresses from DER sources can cause transformer equipment failure, surge arrester failure, nuisance outages from sympathetic tripping and other similar effects.

Toronto Hydro must manage the capacity and type of generation connected to both feeders and stations to ensure reliable operation and prevent damage to existing infrastructure. Introducing increased levels of bi-directional flows from DER will require protection, monitoring, and control to prevent such occurrences during normal operation, planned work and emergency situations.

At this time, there is a limited set of options for addressing DER constraints. As part of its Grid Modernization Roadmap and in anticipation of a high-DER future, Toronto Hydro is investigating and pursuing technologies and solutions that can provide for incremental flexibility in DER integration, including through more predictive and dynamic forms of DER management within grid operations.[5] For example, the energy storage systems (ESS) program is expanding to deploy grid-side batteries to (1) relieve system constraints thereby enabling more renewable hosting capacity on the grid; and (2) respond to the dynamic output of renewable energy sources by acting as a load-generation buffer in periods of mismatch. Furthermore, advances in the Advanced Distribution Management System

[5] See EB-2023-0195, Exhibit 2B, Section D5 for Grid Modernization Roadmap.

("ADMS") and Distributed Energy Resource Management System ("DERMS"), which are systems designed to provide a holistic view of the grid and optimize operations through real-time telemetry and control algorithms, can also enable DER utilization at a higher capacity factor and in turn, allow DERs to participate in grid services at more dynamic and granular levels.

1. Short Circuit Capacity Limitations

Short circuit limits on both the Toronto Hydro and Hydro One system are important factors in determining how much DER can be connected to Toronto Hydro's distribution system. This is because short circuit capacity is the measure that ensures certain power distribution assets are within their recommended withstand thresholds. The primary limiting element for short circuit capacity is substation equipment (where fault current levels are highest) and, more specifically, substation load side breakers.

Currently, three station buses have reached short circuit capacity limits and are not able to connect additional DERs. Toronto Hydro anticipates that a total of eight station busses will exceed short circuit capacity by 2029.

Table 4: Current and Forecasted Short Circuit Capacity

Station Name	Bus	2023 Available Short Circuit Capacity (MVA)	2029 Available Short Circuit Capacity (MVA)
Cecil	CE-A1A2	59.7	-32.7
Ellesmere	H9-J	81.0	-5.4
Esplanade	X-A1A2	58.9	-7.6
Leslie	51-BY	3.2	-46.6
Richview	88-BY	-40.3	-41.2
Runnymede	11-JQ	113.6	-103.3
Sheppard	47-EZ	-57.3	-91.4
Woodbridge	D6-BY	-27.3	-28.0

To arrive at the projected constraints in Table 4, Toronto Hydro mapped its overall forecast of 2029 DER capacity onto station busses by assuming that the geospatial distribution of DERs will continue to follow existing load connection patterns.

Toronto Hydro manages short circuit capacity limitations through two methods: 1) bus-tie reactors; and 2) increased fault levels. Each of these is described in further detail below.

Note that traditional station expansions investments can also relieve short circuit capacity limitations by introducing distribution equipment with higher capacity or greater short circuit withstand limits. However, given the significant cost and time involved, it is not economical to expand a station solely for the benefit of connecting DERs. Rather, increased DER connection capacity can be considered a secondary benefit of planned station expansions, which will be required in the normal course to accommodate increasing load demand in specific regions of the city. For example, the planned expansion of Sheppard TS will have the secondary benefit of helping to alleviate the existing short circuit constraint. The remaining station busses forecasted to require relief as described above will not, however, be addressed through stations expansion investments.

a. Bus-Tie Reactors

To facilitate DER connections, bus-tie reactors can be installed on the bus to mitigate high fault current levels. This technology lowers short circuit current on the station bus and distribution system by inserting impedance at the bus-tie point. This limits the fault contribution of the two transformer windings in a typical Dual Element Spot Network ("DESN") type station arrangement. A reactor of 0.5 ohms installed at a bus-tie could allow up to an additional 15 MW of DER capacity. The actual size of a reactor depends on site specific constraints such as space, etc. Since they are essentially a linear inductive reactance, their cumulative impedance will add to the system's impedance which will result in a reduction of the fault currents. The main advantage of series reactors is that they allow the use of existing equipment without costly modifications or replacements.

Toronto Hydro has engaged Hydro One to coordinate bus-tie reactor installations at stations where fault current constraints have become or are likely to be an issue in the near future. Based on current forecasts, of the eight stations requiring relief by 2029, Toronto Hydro anticipates installing six bus-tie reactors over the 2025-2029 rate period to alleviate short circuit capacity constraints, as summarized in Table 5: Bus Tie Reactor Installations below.

Of the remaining two stations, Sheppard TS would not be a good candidate for a bus-tie reactor due to its use of a gas-insulated bus but has potential upcoming station expansion work that could also increase short circuit limits at the station. For Ellesmere TS, the short circuit constraint may be addressed using an alternative measure described below.

Table 5: Bus Tie Reactor Installations

Station Name	Bus	Year
Richview	88-BY	2025
Runnymede	11-JQ	2026
Cecil	CE-A1A2	2027
Esplanade	X-A1A2	2028
Leslie	51-BY	2029
Woodbridge	D6-BY	2029

b. Increased Fault Level for 27.6 kV Stations

Another solution to short circuit capacity constraints, in some limited circumstances, is operating at an increased fault level. There is no cost associated with operating at the increased fault level, but it is deemed to be a temporary solution due to the minimal short circuit capacity it relieves. Currently, Toronto Hydro operates at 16.7 kA fault level for stations operating at 27.6 kV. The Transmission System Code provides that 27.6 kV stations may operate at a fault level up to 17 kA, creating additional short circuit capacity.[6] Hydro One must approve an application from a distributor to

[6] Appendix 2 of the TSC.

operate at a higher fault level. The solution is only available where customers' equipment fault withstand ratings are verified to be within safe limits, particularly for those customers closest to the station.

Toronto Hydro determined that of the eight stations expected to experience short circuit constraints by 2029, only one bus, Ellesmere TS J bus, met the criteria for operating at the increased fault level without impacting the reliability of connected customers.

E5.5.3.3 System Monitoring to Control Distributed Generation

Lack of monitoring and control over distributed generation on the grid can lead to increased risks of islanding, overloading the system, and increased thermal ratings. These can be addressed through the installation of MCSs.

Currently, Toronto Hydro requires MCSs for DER installations that are equal to or greater than 50 kW. This accounts for almost 95 percent of the total DER capacity connected to Toronto Hydro's grid. This threshold ensures that Toronto Hydro has enough visibility and management of DERs to achieve the objectives of the Program at a reasonable cost.

1. Anti-Islanding Condition for Distributed Energy Resources

Islanding occurs when a DER source continues to power a portion of the grid even after the main utility supply source has been disconnected or is no longer available due to a fault condition. This can create dangerous back-feed on the distribution system, exposing workers to live circuits that they believe are de-energized. This can also interfere with grid protection systems and damage equipment after utility power is restored.

Monitoring and control can mitigate the risks associated with DER for the public and Toronto Hydro field personnel. Rule 84-008 of the *Ontario Electricity Safety Code* ("OESC") requires that DERs have back-feed protection so that in the absence of electrical power (potential) on the utility's supply, DERs cannot energize the utility's supply. If the anti-islanding feature of a DER were to fail, it would back-feed into the local distribution system. The possibility of electric shock due to this scenario would pose a safety risk to the public, Toronto Hydro field personnel, and the system in general. Active monitoring and control systems help avoid this situation by automatically issuing a remote electronic trip or shutdown command when the feeder breaker is opened.

The connection of PV solar inverters and other DER sources must be accomplished in a manner that ensures that unintentional islanding of DER sources cannot occur. Through the MCS equipment logic that reverts the Remote Terminal Unit ("RTU") contact of the remote disconnect device after loss of power from the UPS, islanding conditions are averted. Toronto Hydro plans to continue to deploy real-time monitoring and control investments proposed within this Program at new DER sites greater or equal to 50 kW as per section 3.3.3 of the DSC to provide the needed ability to address anti-islanding concerns.

One of the anti-islanding measures in the IEEE 1547 Standard for Interconnecting Distributed Resources (DR) with Electric Power Systems, section 4.4.1, recommends that a distributor ensure that "*DR aggregate capacity [be] less than one-third of the minimum load of the Local Electric Power System (EPS).*"[7] As the ratio of generation capacity to minimum load increases, the amount of time required by inverters to respond to anti-islanding scenarios also increases and the likelihood of inverters responding to anti-islanding scenarios decreases.

With the proliferation of DER in Toronto in recent years, several feeder circuits have already surpassed the generation to minimum load ratio of one-third. A total of eleven distribution feeders have ratios ranging from 0.30 to 11.51 (refer to Table 6: Existing Feeders with Generation to Load Ratio Greater Than One-Third below). These feeders currently present an increased risk of unintentional islanding conditions to the distribution system.

Table 6: Existing Feeders with Generation to Load Ratio Greater Than One-Third

Feeder Name	TS Station Name	TS Bus	DER Connected (MW) as of Dec. 2022	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
63-M6	Agincourt	Y	3.6	7.6	0.47
53-M3	Bermondsey	B	0.6	2.1	0.30
80-M10	Fairchild	Y	1.4	2.2	0.63
55-M31	Finch	J	1.8	3.6	0.48
R30-M3	Horner	B	0.8	1.7	0.45
38-M4	Manby	F	0.6	0.0	11.51
R29-M5	Rexdale	B	0.9	2.5	0.36
A-35-T	Strachan	A7A8	1.0	0.5	1.99

[7] Institute of Electrical and Electronics Engineers.

Feeder Name	TS Station Name	TS Bus	DER Connected (MW) as of Dec. 2022	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
R43-M31	Warden	J	0.8	2.4	0.35

The forecasted 516.7 MW cumulative of DER capacity anticipated by the year 2029 will further exacerbate the existing islanding risks and adversely affect Toronto Hydro's ability to safely and reliably connect additional DER to the distribution system. Monitoring and Control Systems allow Toronto Hydro to prevent concerns of anti-islanding as these give the utility the ability to remotely turn off the DER if they unintentionally island. If the generation to minimum load ratios are not addressed by proactive investments in control and monitoring capabilities, they could ultimately limit the number of DERs Toronto Hydro is able to connect to the system. These systems also provide greater visibility into the grid and allow the utility to enable more DERs to connect, as explained in section E5.5.3.3.

2. System Thermal Limits and Load Transfer Capability

Protection, monitoring and control upgrades also provide the ability to connect additional DER by ensuring system loading thresholds are satisfied. Exceeding system loading limits, as seen in Table 6: Existing Feeders with Generation to Load Ratio Greater Than One-Third, sacrifices the life of distribution equipment and can cause immediate equipment failure as mentioned earlier.

For large sized generation connections or the aggregation of small and medium sized generation connections, limiting a feeder's continuous load thermal ratings is an important operating condition. Feeder planning and operation account for the system impact when the generator is up and running as well as when the units go off-line. These thermal levels come into play with factors such as the variability of various generation sources, system load growth and the occurrence of contingencies. Simply put, the MCS equipment helps ensure that the generation is within the level that will not strain the distribution system equipment under certain conditions.

The ability to provide monitoring and control allows Toronto Hydro to monitor and mitigate the impact of thermal loading by, for example, transferring load between feeders. This enables the utility to have more visibility into actual impact and variability of DER on the system and will therefore enable Toronto Hydro to be better equipped to make more accurate planning and operations decisions regarding thermal levels.

3. Monitoring and Control Systems

Since the 2015-2019 rate period, Toronto Hydro has required and facilitated the installation of monitoring and control systems for all new DER connections greater than 50 kW. This has provided the visibility required to monitor system conditions in real time and to ensure all DER sites are de-energized in the event of a system fault. With the continued implementation of the Program, Toronto Hydro will be able to actively monitor and control DERs in real time to ensure operation within acceptable levels and that the anti-islanding feature of the DERs have properly operated in the event of a distribution system fault.

Figure three depicts the required real-time monitoring and control via utility communication networks and the supervisory control and data acquisition ("SCADA") system.

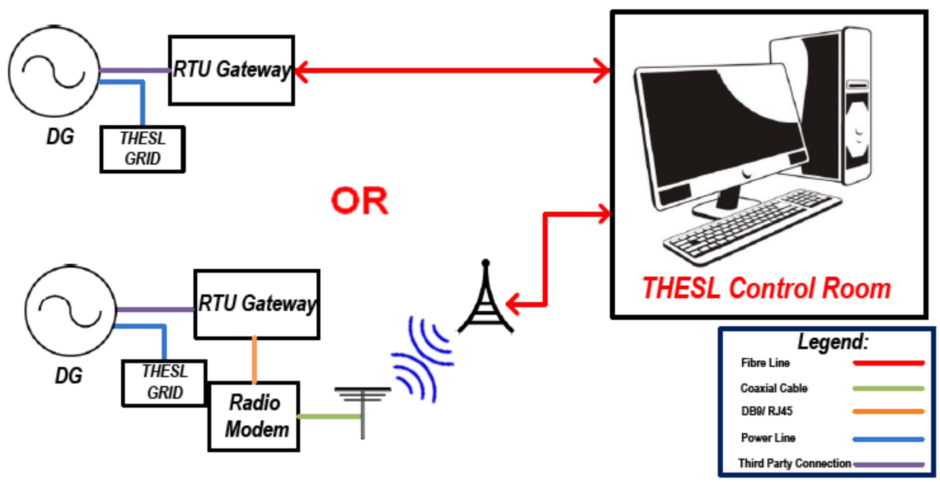


Figure 3: Monitoring and Control Interface to Toronto Hydro SCADA System

Monitoring and control also enables greater real-time visibility into the operating conditions of DER sites located in Toronto Hydro's service territory. Power system controllers need to know the aggregate generation connected to the system during planned or emergency load transfers. A power system controller must account for all DER during a load transfer because the increase in generation connected to the alternate feeder may cause short circuit capacity to be exceeded. The ability to remotely and automatically disconnect all DER sites on a feeder during planned or emergency load transfers is expected to simplify these operations as it would allow power system controllers to focus on restoration of customers' electricity rather than each individual DER site connected to a feeder.

Monitoring and control provide situational awareness into the operating conditions of all DER connected to the distribution system, which will give Toronto Hydro the ability to collect data for planning purposes and to connect additional DER sites to the distribution system. This will have additional long-term value with respect to planning for future DER connections. Currently, Toronto Hydro assesses the potential to connect a DER site to the distribution system based on estimated thermal loading values. This approach assumes that a DER site will continuously generate 100 percent of its rated capacity. This inherently limits the number of DER sites that can be connected to the system, because the conservative estimated value assumes that the thermal loading of the DER site is greater than it likely is at any given time. Monitoring and control will provide Toronto Hydro actual performance data from in-service connections for thermal loading values which will give a more precise view of existing conditions. This, in turn, will feed into DER hosting capacity analyses to automate visualization of estimated available capacity and facilitate cost-effective integration of additional DER on the distribution system. Real-time data will also serve as building blocks for expanding DER connection types through the Flexible Connections pilot concept under the Innovation Fund segment.[8]

Toronto Hydro's requirement for monitoring and control is modeled after requirements developed by the IESO. The IESO has developed DER monitoring and control guidelines with a focus on visibility, dispatch and forecasting capabilities for DER sites over 5 MW. Because of the volume and capacity of DER sites in Toronto Hydro's service territory (over 304.9 MW in aggregate as of the end of 2022), monitoring and control is required to connect additional DER projects and for grid management. This is also consistent with the requirements and practices of other distributors.

Toronto Hydro's current monitoring and control process allows for the connection of DER sites through a Toronto Hydro communication interface as shown in Figure 4 below along with the standards it adheres to. Figure 5 shows a customer installation, which also adheres to Toronto Hydro standards.

[8] See EB-2023-0195, Exhibit 1B, Tab 04, Schedule 02 for Innovation Fund.

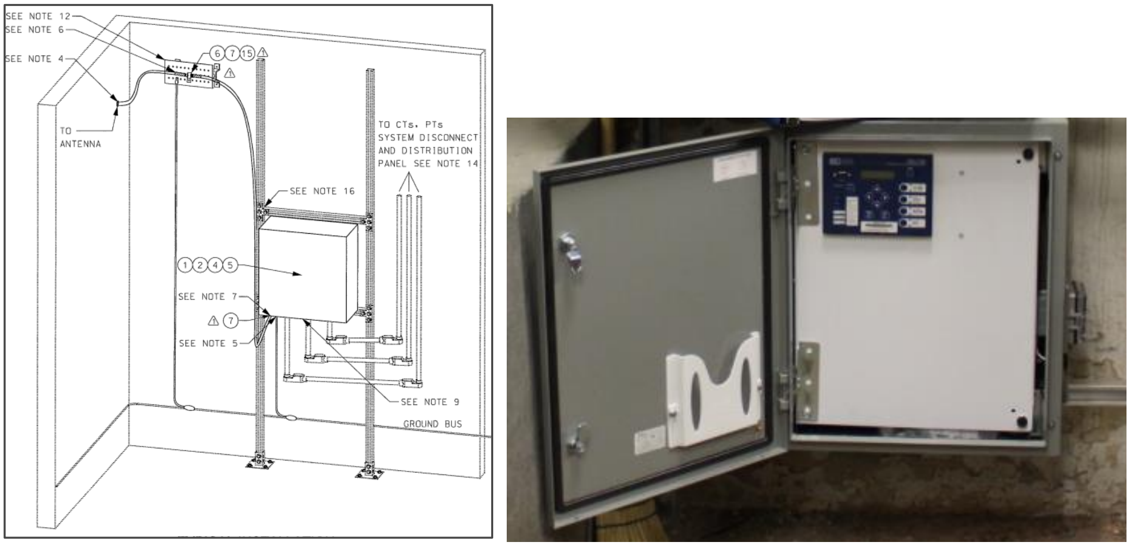


Figure 4: Toronto Hydro Communication Standard for DER Connections (left) and Communication Gateway Installed at Customer DER Site

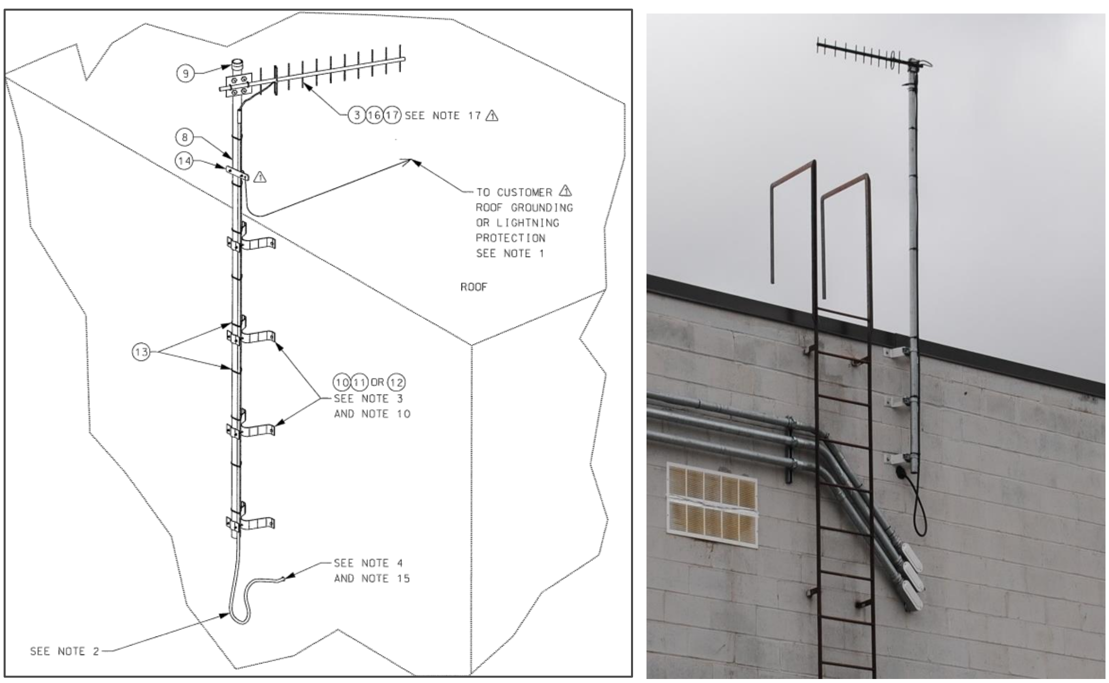


Figure 5: Toronto Hydro Communication Antenna Setup Standard (left) and at a Customer Site (right)

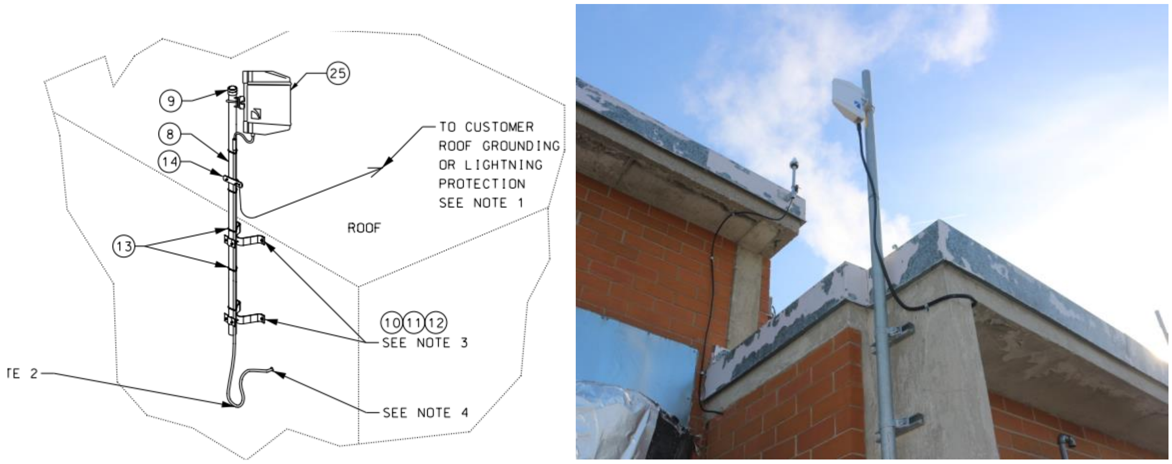


Figure 6: Toronto Hydro Alternative Type Communication Antenna Setup Standard (left) and at a Customer Site (right)

E5.5.4 Expenditure Plan

Table 4: Historical, Bridge & Forecast Program Costs ($ Millions)

	Actual		Bridge			Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Generation Protection, Monitoring, and Control	0.8	0.8	0.1	4.1	5.3	5.9	6.1	6.3	6.5	10.3

E5.5.4.1 2020-2024 Variance

1. Generation Protection

The plan for the 2020-2024 rate period was to install bus-tie reactors at five Hydro One owned and operated transformer substations (Ellesmere TS J bus, Esplanade TS A1A2 bus, Fairbank TS YZ bus, Horner TS BY bus and Sheppard TS BY bus) which Toronto Hydro anticipated would reach short circuit capacity by 2024. As of June 2023, three station busses currently need relief, and of those stations, only Sheppard TS is from the 2020-2024 forecast. These variances can be attributed to both the challenge of accurately predicting where customers will choose to install DERs, as well as a slower rate of DER renewable applications, particularly after the conclusion of the Feed-In-Tariff program and other government incentive driven DER programs (Process and System Upgrade Incentive, etc.).

After consultation with Hydro One, Toronto Hydro ruled-out Sheppard TS for a bus-tie reactor in the 2020-2024 rate period due to technical limitations imposed by the Gas Insulated Switchgear (GIS) bus. This is in addition to a proposed station expansion initiative planned in the near future.

Hydro One and Toronto Hydro carried-out a further study of various bus-tie reactor candidates, which ultimately resulted in the elimination or deferral of a number of potential projects due to technical, physical, or logistical constraints. Richview TS currently stands as the only immediate candidate for a bus-tie reactor installation in the 2020-2024 rate period as its 88-BY bus currently exceeds short circuit capacity limits and the project appears to meet Hydro One's short term feasibility criteria. Toronto Hydro will continue to collaborate with Hydro One to pursue a reactor installation at Richview in the 2020-2024 rate period. The cost associated with the procurement and installation of a bus-tie reactor is roughly estimated at approximately $3 million with actual project cost expected to differ between sites depending on location specific factors such as spacing constraints and electrical configuration, in addition to the current supply chain environment. In the event that the Richview TS station bus-tie reactor installation does not materialize in the current rate period, Toronto Hydro is forecasting it to be implemented early on the next 2025-2029 rate period.

2. Monitoring and Control

For 2020-2024 rate period, the monitoring and control segment was split into three initiatives:

a. MCS Buyback Program;
b. Antenna Installation Program; and
c. New DER Meter and RTU Issuance.

a. MCS Buyback Program

Between 2012 and 2017, there were over 400 renewable generation connections where the customer purchased and installed MCS for their facilities. Sections 3.3.2(g) and 3.3.3 of the DSC provide that utility is responsible for costs incurred related to SCADA system design, construction and connection for renewable energy generation facilities. In compliance with this obligation, Toronto Hydro undertook to reimburse those customers that had directly purchased their MCS. This process involves the negotiation of agreements to purchase the MCS and assign necessary access rights, warranties, etc., in order to facilitate Toronto Hydro's ongoing management of the MCS.

At the start of 2020, there was a total of 135 MCSs that Toronto Hydro needed to buy back from customers at an estimated cost of $135,000. Out of that total number:

- 19 have completed the buyback process;
- 18 are in the purchase agreement sign off stage; and
- the remaining 98 are in audit or deficiency rectification stages, with target completion by the end of 2024.

Note that Covid-19 pandemic related restrictions and limitations temporarily prohibited access to sites, primarily affecting site audit procedures and causing delays to program execution.

b. Antenna Installation Program

In addition to the purchase of 400+ MCS from past customers, Toronto Hydro is installing the radio communication link equipment required to facilitate the two-way communication flow between these DER facilities and the Toronto Hydro Control Centre. Installation began in 2020 and, to date, Toronto Hydro has completed installations at more than 100 sites. The program experienced some delays due to needed updates on the software security and performance settings for these assets. Revisions to installation standards were also required in order to allow new optimal equipment to be installed and connected based on site specific requirements (Antenna type, Modem type, Mounting provision changes, etc.). In addition, the hardware has been updated to LTE technology which is the 3rd iteration from the former GE SD9 and GE Orbit radio modems. Toronto Hydro is mitigating the risk of scope ambiguity going forward by developing a new RFP that provides greater clarity on scope of work requirements. This program is expected to continue past the 2020-2024 rate period and into the 2025-2029 rate period which would cover newer installations as well.

c. New DER Meter and RTU Issuance

The forecast for new M&C equipment for 2020 to 2022 was 31. There were 26 units ordered.

E5.5.4.2 2025-2029 Forecast

Based on current DER forecasts, the Program is projected to cost $35.0 million over the 2025 to 2029 period.

Table 8: Forecast Program Costs ($ Millions)

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Generation Protection - Bus Tie Reactor	3.2	3.3	3.4	3.5	7.1
Generation Protection - Monitoring and Control	2.6	2.8	2.9	3.0	3.2
Total	**5.9**	**6.1**	**6.3**	**6.5**	**10.3**

1. Bus-Tie Reactors

Toronto Hydro regularly monitors short circuit capacity trends to identify where constraints may emerge. Based on current information, Toronto Hydro anticipates that eight stations will require relief by the end of 2029. Ellesmere TS can be addressed at no cost by increasing fault limits. Sheppard TS will be addressed through planned expansion work. Bus tie reactors will be required to mitigate short circuit capacity limitations at the remaining six transformer stations at a cost of $20.4 million.

Toronto Hydro plans to begin the design and construction of the first reactor in 2025 and complete installations of six reactor by 2029.

Table 9: Bus Tie Reactor Installations Cost and Installation Schedule ($M)

Station Name	Bus	2025	2026	2027	2028	2029	2025-2029
Richview	88-BY	3.2					
Runnymede	11-JQ		3.3				
Cecil	CE-A1A2			3.4			
Esplanade	X-A1A2				3.5		
Leslie	51-BY					3.5	
Woodbridge	D6-BY					3.6	
Total		**3.2**	**3.3**	**3.4**	**3.5**	**7.1**	**20.4**

Bus-tie reactor installations will occur in accordance with Hydro One feasibility studies. Hydro One will assess station space constraints, station operation disruption, and overall project viability for each site.

2. Monitoring & Control (“MCS”)

Pursuant to sections 3.3.2(g) and 3.3.3 of the DSC, Toronto Hydro is required to bear the costs related to communication systems (i.e. MCS) to accommodate the connection of renewable energy generation facilities. For all non-renewable energy generation facilities, the customer is responsible for costs relating to the MCS.

The timing and pacing of the installation of MCSs is driven by customer requests to connect DER to the distribution system. The estimated costs of the installation of MCSs over the 2025 to 2029 period at $14.5 million is based on forecasted DER connections as discussed above in section 5.5.3.1. The equipment and installation costs associated with the integration of a DER site into Toronto Hydro's SCADA system is approximately $25,000 and is based on historical DER MCS installations.

E5.5.4.3 Project Prioritization

The Program is driven by customer requests to connect DER to the distribution system and as such, are prioritized on a first come, first served basis. DER customer timelines and deadlines are considered to minimize disruptions and allow for efficiencies, whenever possible.

E5.5.4.4 Cost Management

Toronto Hydro continuously evaluates the selection of bus tie reactor projects to ensure investment is in the appropriate areas. For example, the utility re-evaluates station bus short circuit levels after each new connection application is received for that bus. Connection Impact Assessments ("CIA") are performed for each new DER and are the basis for determining if buses require short circuit relief.

Toronto Hydro is also regularly engaging with Hydro One and is made aware of future station transformer upgrades that could relieve short capacity constraints.

For both segments, variance analyses will also be performed to identify areas for improvement and future cost management.

E5.5.5 Options Analysis

E5.5.5.1 Option 1: Do Nothing

Under this option, Toronto Hydro does not install any bus tie reactors or MCSs. DER connections would continue to occur on parts of the distribution system where they could be accommodated, up until the point where technical limitations are reached. This option will increase the number of DER application rejections and reduce reliability as Toronto Hydro would reach its operational and system design limits which would potentially make the distribution system sensitive to fault conditions with a reduced safety buffer.

Additionally, the inability to have situational awareness and a more precise view into the operating conditions of DER that could impact the grid (through the installation of MCSs), would reduce the utility's capacity to connect additional DER facilities to the distribution system in the future. Failure to connect renewable DER facilities to the Toronto Hydro distribution system would result in non-compliance with the requirements of Toronto Hydro's distribution license, the DSC and *the Electricity Act*, *1998*. As mentioned per Section 6.2.4 of the DSC, and sections 25.36 and 25.37 of the *Electricity Act, 1998* Toronto Hydro is obligated to connect DER customers to its distribution system. Toronto Hydro is also obligated under section 6.1 of its Distribution License and section 26 of the *Electricity Act, 1998* to provide generators with non-discriminatory access to its distribution system. To comply with these obligations, Toronto Hydro evaluated two alternatives (major asset upgrades and the Generation Protection, Monitoring, and Control program) for addressing the system constraints that currently limit the utility's ability to connect the growing demand for DER on the system and safely and reliably manage DER connected to the distribution system.

Without active monitoring of DER facilities, there is an increased risk of unintentional islanding and unintentional back-feed that could have an adverse effect to the grid from DER sources thus reducing reliability on the system. This presents an increased risk to Toronto Hydro linespersons as they will be exposed to back-feed situations. Therefore, Toronto Hydro does not recommend this option.

E5.5.5.2 Option 2 (Selected Option): GPMC Program

The GPMC Program is the preferred alternative, as it is a much more timely and cost-effective solution and would allow for the continued integration, expanded visibility, and monitoring and control of DER connected to the Toronto Hydro distribution system.

In addition, Toronto Hydro expects that the program's solutions will enable prediction of the amount of generation produced by DER connected to the distribution system, a capability that is not currently available to system planners. With performance data gathered through the Generation Protection, Monitoring, and Control program, Toronto Hydro will be able to make better informed decisions on the design and operation of the distribution system. The program would better prepare Toronto Hydro to deliver on commitments to help customers electrify quicker and easier by optimizing use of existing infrastructure.

The program would further advance the Toronto Hydro mandate to facilitate DER connections by directly alleviating technical barriers to connecting DERs, particularly renewable energy sources and energy storage systems, by investing in additional hosting capacity through the installation of bus-tie reactors on Toronto Hydro TSs identified to have short circuit constraints.

The overall cost of this option is $35.0 million over the 2025-2029 rate period.

E5.5.5.3 Option 3: Major Asset Upgrades

As an alternative to the work planned within the Program, Toronto Hydro could address DER requirements via major asset upgrades at transformer stations where short circuit capacity constraints exist. Assets to be upgraded include power transformers and switchgear. Monitoring and control equipment would also be installed as part of this option. However, with a cost of roughly $19M per switchgear upgrade, not to mention complex coordination of outage and feeder transfers, this would be an uneconomical and impractical approach to enabling incremental DER hosting capacity on the system.

E5.5.6 Continuous Improvement and Productivity

With the implementation of MCS, Toronto Hydro will have access to real time data for all generation sites greater than 50 kW. The information obtained from the MCS and the Energy Monitoring and Control Capabilities can be integrated with distribution system analysis software to produce simulations and reports in a more timely, accurate and efficient manner. This would result in CIA's being completed within the prescribed time at a higher rate. In addition, cellular communication would be the communication medium to be utilized long term using similar architecture of the current radio antenna. This would increase the communication bandwidth for DER telemetry for more precise readings through an increase in communication frequency.

For the bus-tie reactor program, continued emphasis to find the most optimal approach for implementing the reactor installation to increase DER enablement is to be performed. This would be done through fault analysis studies within the on-going coordination initiatives with Hydro One.

MCS assets have the added benefit of integrating with Toronto Hydro's DERMS platform, Energy Centre, to perform real-time coordination and control of DER assets to capitalize on resource management. The RTU embedded within the MCS plays a key role in the integration of other smart grid assets such as smart inverters and microgrids that are detailed in the Non-Wires Alternatives program. Finally, as DER penetration begins to densify on parts of the grid, the communication infrastructure will be crucial to enable aggregation and scalability of DER control from feeder to bus level and beyond.

E5.5.7 Execution Risks & Mitigation

The forthcoming HONI feasibility study for bus-tie reactors could reveal station limitations that deem the reactor installation implausible in certain locations. In these cases, Toronto Hydro will explore other potential short circuit constraint mitigation interventions (e.g. split-bus configuration schemes) before ruling out the possibility of station-level hosting capacity relief in the near-term.

With respect to the Monitoring and Control segment, communication infrastructure (i.e. radio network) may need to be expanded or upgraded to handle a high volume of DER connections. Toronto Hydro is in the process of migrating most of its communication infrastructure to IP based equipment. This would bring about changes to hardware in place and an upgrade program has to be implemented to accommodate such.

Global supply chain shortage would also be another factor that might affect the timeline for execution of both the MCS and bus-tie reactor segments. Engaging vendors early and often to provide the necessary equipment would be key to managing the current delay from manufacturers.

E6.1 Area Conversions

E6.1.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 207.6	**2025-2029 Cost ($M):** 236.7
Segments: Rear Lot Conversion, Box Construction Conversion	
Trigger Driver: Functional Obsolescence	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Customer Focus	

The Area Conversions program ("the Program") funds the replacement of legacy 4.16 kV distribution system designs with updated standard 13.8 kV and 27.6 kV lines, focusing on two unique functionally obsolete 4.16 kV systems known as Rear Lot Construction and Box Construction. These systems serve residential customers in the Horseshoe region, and small commercial and residential customers in the downtown area. The Program is designed to address below-average customer reliability outcomes, mitigate public and employee safety risks, and overcome other operational and customer service deficiencies posed by these legacy and aging systems.

This Program is grouped into the following segments and it is a continuation of the renewal activities described in Toronto Hydro's 2020-2024 Distribution System Plan ("DSP").[1]

- **Rear Lot Conversion:** this segment continues the replacement of functionally obsolete distribution system designs, installed in the backyard, or rear lot, with standard front lot underground supply. Typically installed over 50 years ago, these assets serving residential customers in the Horseshoe region of Toronto feature below-average reliability outcomes for customers, safety concerns for crews and the public, and other operational and customer service deficiencies. Toronto Hydro is on track to successfully upgrade approximately 683 rear lot customers to front lot 27.6 kV underground services during the 2020-2024 rate period. Toronto Hydro's overall objective for this segment is to prevent rear lot equipment failure risk from worsening, as failures are likely to result in long duration outages and ongoing safety risks to customers and crews from rear lot plant. To this end, Toronto Hydro plans to invest $120.6 million to convert 1,467 customers between 2025-2029, an increase

[1] EB-2018-0165, Exhibit 2B, Section E6.1.

in pacing that reflects an observed increase in the number of assets past useful life on the rear lot system since 2014.

- **Box Construction Conversion:** a continuation of Toronto Hydro's plan to eliminate aging 4.16 kV box construction feeders from the pre-amalgamation City of Toronto. These overhead feeders are located along main streets in the downtown area and serve residential and small commercial customers. Toronto Hydro no longer builds the system to this standard due to safety compliance, reliability, access, equipment, capacity, and procurement issues. The congested box-like framing of the circuits prevents crews from establishing safe limits of approach to live conductors, which in turn restrict operations and leads to longer power restoration times when compared to modern overhead standards. During the 2020-2024 rate period, Toronto Hydro expects to convert a total of approximately 3,368 poles from the legacy 4.16 kV to the standard 13.8 kV overhead system, which will remove an estimated 680 box-framed poles from the system. Toronto Hydro is planning to spend $116.1 million to continue conversion of the remaining box construction areas over the 2025-2029 rate period, prioritizing the removal of the last 344 box-framed poles by 2026 to eliminate the various safety and reliability risks these assets present to employees and the public.

Toronto Hydro plans to invest $236.7 million in the program in the 2025-2029 rate period, which is a 14 percent increase over projected 2020-2024 spending (including forecasted inflation). This pace of investment is necessary to mitigate the reliability and the safety risks of these functionally obsolete systems.

E6.1.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Eliminating the risk of long (i.e. 5 to 24+ hours) rear lot outages for an estimated 1,467 residential customers in the worst performing rear lot areas. ○ Improving average outage restoration times for 15,246 residential and small business customers downtown by eliminating the remaining 344 box-framed poles from the system.

Operational Effectiveness - Safety	• Contributes to public safety performance and employee safety by mitigating safety risks that are unique to obsolete rear lot and box construction systems. Specifically: ○ Eliminate safety risks to address compliance issues (i.e. relating to Electric Utility Safety Rule 129 - safe limits of approach, Canadian Standards Association and Electrical Safety Authority) associated with legacy box construction feeders by replacing remaining box construction assets. ○ Increase the pace of rear lot conversion investment in order to better manage the increasing risk of equipment failure and subsequent safety issues arising from crew access and public exposure to rear lot access.
Customer Focus	• Contributes to Toronto Hydro's customer service performance and customer satisfaction by: ○ Minimizing the need for unplanned crew access to customer property by converting approximately 1,467 residential rear lot customers to front lot service. ○ Improving the speed and cost-efficiency of customer grid access (including for generation and electric vehicles) in high-growth areas of downtown Toronto by converting approximately 1,681 poles from 4.16 kV to 13.6 kV. ○ Reducing public traffic disruptions on main city streets from an operational and maintenance perspective (i.e. less frequent repairs and visits) once the box construction is converted.

E6.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Functional Obsolescence
Secondary Driver(s)	Reliability, Safety, Capacity

This Program addresses distribution assets with legacy design features that result in substandard reliability performance for customers, safety risks for crews and the public, capacity constraints for the system and other undesirable outcomes. For these reasons, Toronto Hydro consider these assets to be functionally obsolete.

The risk of failure increases as these assets age and deteriorate. Hence, Toronto Hydro prioritizes these assets for replacement in order to maintain acceptable reliability outcomes and mitigate exposure to safety risks.

Rebuilding these systems on a like-for-like basis is not a viable option due to the substandard performance, material availability, compatibility issues and safety risks inherent to the existing designs. Furthermore, Toronto Hydro is gradually phasing out its 4.16 kV distribution system in favour of the more efficient 13.8 kV and 27.6 kV systems, which are also better suited to efficiently handle urban growth and development in the City of Toronto.

The following sections provide more detailed information about the drivers of work in the Rear Lot Conversion and Box Construction Conversion segments.

E6.1.3.1 Rear Lot Conversion

The Rear Lot Conversion segment is a continuation of Toronto Hydro's plan to convert and re-supply rear lot customers with underground front lot services. As illustrated in Figure 1 below, the replacement front lot design supplies customers through lateral underground 27.6 kV primary circuits along the roadways with predominantly padmounted transformers. Once customers are connected to the improved configuration, all former rear lot assets are removed to eliminate any existing safety risks.

Figure 1: Legacy Rear Lot Supply vs. Replacement Front Lot Supply.

Rear Lot Conversion is necessary to address reliability and safety risks that are caused or exacerbated by poor accessibility and physical encroachments inherent to the existing rear lot plant location.

1. Rear Lot Reliability Issues

Rear lot plant was generally built in the 1960s and a large portion of these assets are operating beyond their useful lives. As the plant ages, the risk of outages caused by equipment failure increases. Notably, rear lot plant consistently experiences longer duration outages than the average Toronto Hydro feeder (as illustrated in Figure 2 below), primarily due to the difficulty crews face in locating faults and safely accessing and repairing equipment.

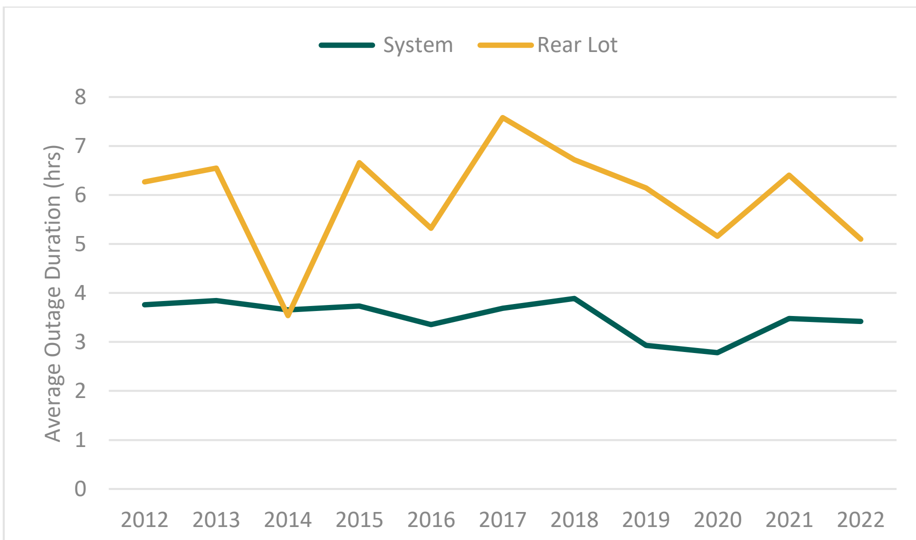


Figure 2: Average Outage Duration Excluding Major Event Days ("MEDs"): Rear Lot vs. All Feeders

On average, over the 2012-2022 period, outages on rear lot feeders were 2.5 hours longer than outages on the system as a whole.

Over the long term, by limiting and reducing the volume of end-of-life rear lot assets, Toronto Hydro aims to prudently manage the safety and reliability risks associated with their failure. The average age of the rear lot distribution is already higher than the useful life expectancy of 50 years for most assets. This average age continues to grow rapidly when compared to the rate of conversion, increasing failure risk. It is estimated that by 2029 the average age of the remaining rear lot system will surpass 60 years.

Figure 3 below shows the growing number of customers that will be served by increasingly aged rear lot plant if not addressed.

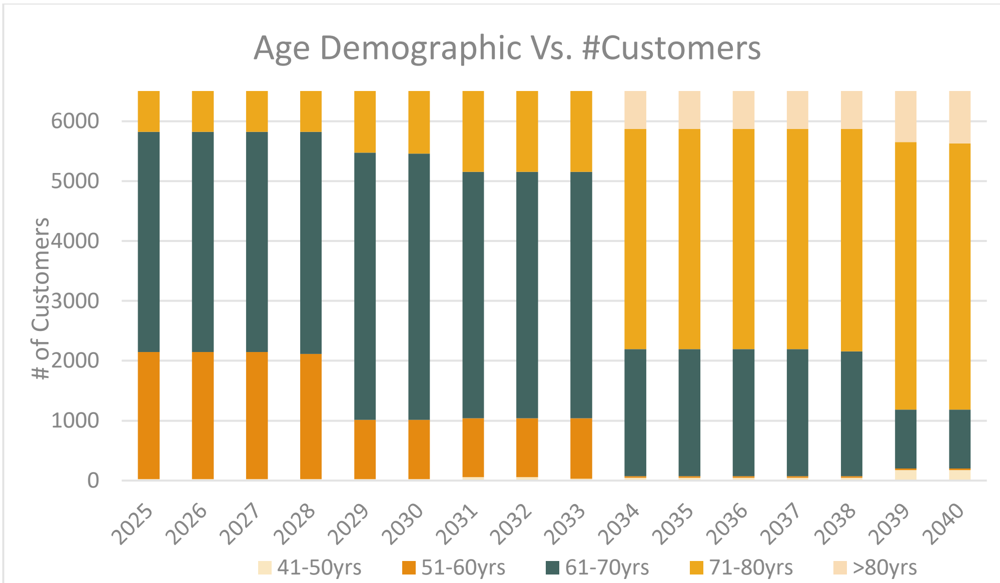


Figure 3: Rear Lot Age Demographic and Number of Customers Supplied

The relatively poor performance of Toronto Hydro's rear lot distribution system is further demonstrated by the number of incidents resulting in loss of service to rear lot customers for at least one day. The location of the infrastructure (i.e. in backyards, often in close proximity to trees, swimming pools and vegetation), and its deteriorating condition make rear lot distribution plant particularly vulnerable during storms and other severe weather events. Furthermore, Toronto Hydro's primary assets in rear lot areas are attached to poles that are predominantly owned by a third-party company, i.e. Bell, making it more difficult for Toronto Hydro to perform maintenance and reactive work to maintain these assets in good condition. Table 4 below contains examples of outages longer than 24 hours in duration that have occurred in rear lot areas. In all cases, accessibility challenges contributed to prolonged outage durations. Many outages on rear lot feeders greatly exceed five hours, as shown in Table 4 below. Toronto Hydro's recent customer engagement demonstrated that reliability, in particular reducing restoration time in extreme weather, is a top priority for residential customers.

Table 4: Long Duration (at least 24hrs) Events on Rear Lot Areas

Date	Station	Feeder	Cause	Duration (hrs)	MED[2] (Y/N)
01-Jun-12	*SCARBOROUGH WEST TS*	NAE5-2M3	WIND EXTREME / ADVERSE WEATHER	25.4	N
19-Jul-13	*BLACKFRIAR MS*	VCF1	WIND EXTREME / ADVERSE WEATHER	44.6	N
19-Dec-13	*LONGFIELD MS*	BHF1	WIND EXTREME / ADVERSE WEATHER	34.5	N
28-Aug-13	*SCARBOROUGH WEST TS*	NAE5-2M3	FREEZING RAIN EXTREME / ADVERSE WEATHER	26.6	N
05-May-17	*ALBION MS*	MGF1	CABLE - PRIMARY / DEFECTIVE EQUIPMENT	26.3	N
04-May-18	*LONGFIELD MS*	BHF1	WIND EXTREME / ADVERSE WEATHER	72.2	Y
05-May-18	*OBERON MS*	UEF3	WIND EXTREME / ADVERSE WEATHER	25.0	N
06-Nov-18	*DELAMERE MS*	PFF3	CABLE - PRIMARY / DEFECTIVE EQUIPMENT	24.4	N
11-Jan-20	*MILL MS*	LFF2	RAIN EXTREME / ADVERSE WEATHER	28.2	N
08-Jul-20	*CHAPMAN MS*	EBF1	RAIN EXTREME / ADVERSE WEATHER	24.0	Y
21-May-22	*WARDEN TS*	NAR43M23	ADVERSE WEATHER / TREE CONTACTS	53.1	Y
21-May-22	*OBERON MS*	UEF2	ADVERSE WEATHER / TREE CONTACTS	49.1	Y
21-May-22	*DALEGROVE MS*	RCF1	ADVERSE WEATHER / TREE CONTACTS	49.1	Y

Rear lot reliability issues are caused by the obsolete design of the plant and the challenging environment in which it operates. As an example, Figure 4 below shows the Jamestown residential rear lot area which Toronto Hydro is upgrading over the 2020-2024 rate period. The primary lateral, shown in red, branches off of the main feeder circuit, enters the neighbourhood in between two

[22] Major Event Day.

houses, and is subsequently routed between the rear of residential properties. The secondary circuit, shown in green, branches off and crosses customer properties to the meter base supplying each residence.

Figure 4: Lateral Circuit Configuration - Jamestown former Rear Lot Neighbourhood

Outage restoration issues stem from the following factors, which are common to rear lot areas such as the one depicted in Figure 4:

- **Manual fault detection:** the vast majority of rear lot feeders operate at 4.16 kV and therefore lack fault detection and isolation technologies such as Supervisory Control and Data Acquisition (“SCADA”)-mate switches that are standard in up-to-date distribution systems.

- **Accessibility/Visibility:** in a typical rear lot area, poor access and visibility exacerbate a fault situation, contributing to prolonged outages and inefficient use of resources during fault location and outage restoration. Limited access can restrict the use of standard equipment such as bucket trucks, drilling machines and other machinery and implements. This means that heavy materials such as poles and transformers must be manually carried or even hoisted over the residence by crane. For overhead feeders, specialized reactive crews are needed to physically climb the poles during repairs. For underground feeders, crews must manually dig trenches to repair direct-buried cables.

- **Obstructions:** spatial constraints like trees and fences may prevent crews from walking on an uninterrupted path along the feeder to locate the fault, forcing them to enter multiple residential backyards along the circuit. Once the fault is located, crews often face the difficult task of repairing the fault and restoring service while being mindful of a customer's private property and compliance with electrical safety regulations. For instance, Figure 4 shows the presence of mature trees and swimming pools in the vicinity of Toronto Hydro plant.

- **Non-standard equipment:** the top left area of Figure 4 shows the location of obsolete T-splices (used to split underground distribution circuits). Any outage downstream of a T-splice will affect all customers on the main branch circuit. This is not the case in modern power system design where fuses prevent this undesirable outcome.

The Jamestown area further demonstrates the extent to which reliability can be an issue for rear lots with 23 outages over 2012-2021, the majority of which lasted longer than five hours. This level of service would be considered unacceptable to most customers. Toronto Hydro is rebuilding and upgrading the Jamestown area over the current rate period and reliability has already showed some improvement, with no outages in the areas already converted in 2021 and 2022. Figure 5 below shows the number and duration of outages in the Jamestown area from 2012 to 2022 along with progress made in converting customers (i.e. decrease in rear lot customer count) in the area.

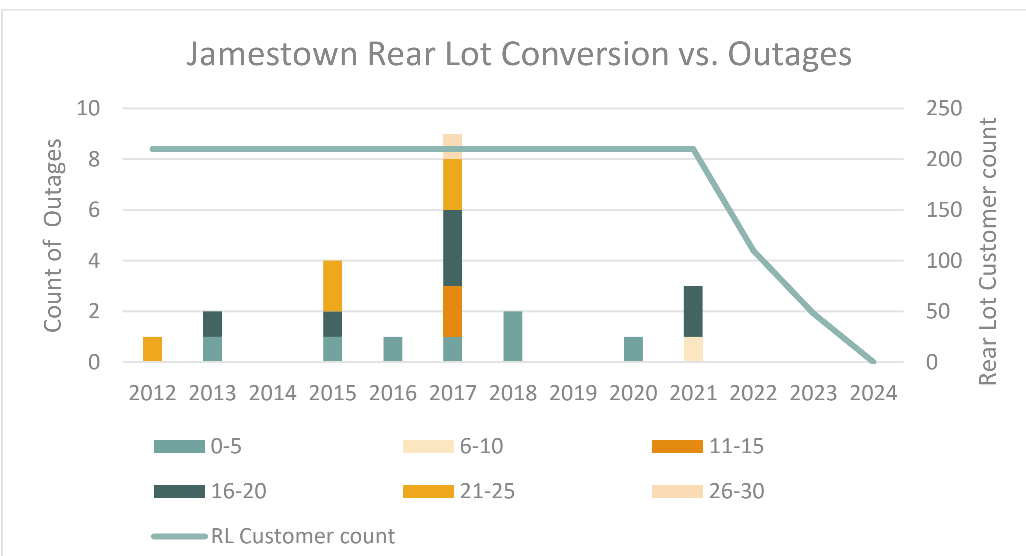


Figure 5: Jamestown Neighbourhood Rear Lot Customer Count and Outage Frequency by Duration

In rear lot areas, 82 percent of the poles have surpassed their useful life and 64 percent of the poles with available asset condition assessment information are showing moderate to material deterioration. Furthermore, 59 percent of the poles in rear lot areas are owned by a third-party company, for which Toronto Hydro has no condition data and it is more difficult for Toronto Hydro to access to perform maintenance and reactive work when required. Table 6 shows the breakdown of Toronto Hydro-owned rear lot poles by asset condition category.

Table 6: ACA Comparison of Toronto Hydro-Owned Rear Lot Poles

Pole Asset Condition Class	% of Assets per Class (2022)
HI1 – Good Condition	28%
HI2 – Minor Deterioration	4%
HI3 – Moderate Deterioration	30%
HI4 – Material Deterioration	27%
HI5 – End of Life	7%
ACA Data Unavailable	3%

Converting an entire rear lot area is a complex and lengthy undertaking that must be carefully sequenced and executed over multiple years. Given the amount and age of the remaining plant, it is necessary for Toronto Hydro to start increasing its pace of proactive Rear Lot Conversion, while prioritizing those areas that are experiencing the worst reliability performance.[3]

Toronto Hydro has ranked feeders according to their reliability performance. The following 'heat map' (Figure 6) shows all rear lot outages from 2012-2022 with dots representing a recorded outage in the rear lot area. The circles overlapping the dots in the chart indicate feeders which have been targeted for conversion in the 2025-2029 rate period. The proposed Rear Lot Conversion plan will continue to address those areas where customers are experiencing the worst service.

[3] Note that Toronto Hydro must ensure that areas that have already been started are fully completed before moving to a new neighborhood, even when those areas are showing temporary reliability improvements due to the partial conversion.

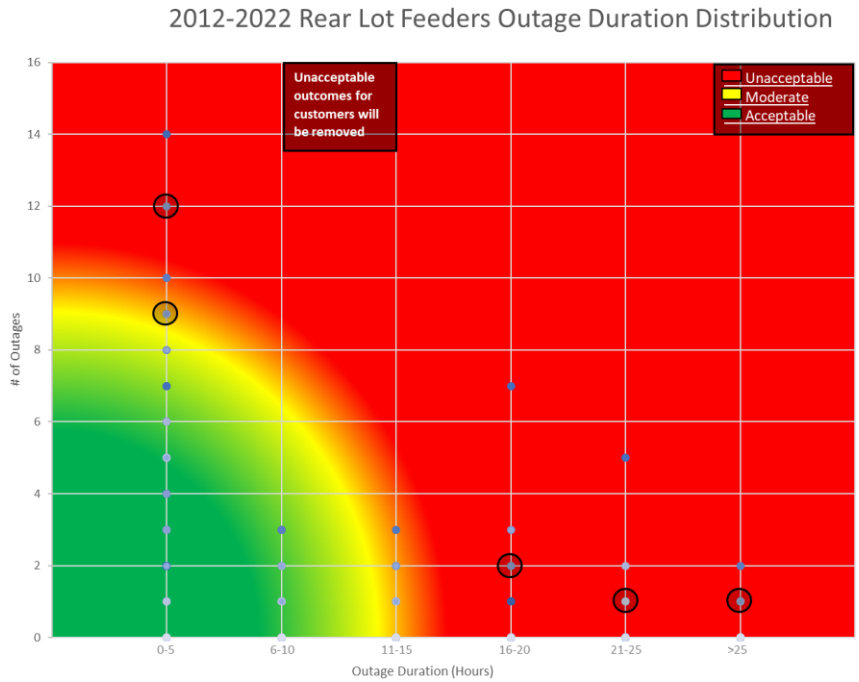


Figure 6: Heat Map of All 2012-2022 Rear Lot Outages

2. Rear Lot Safety Issues

Equally important in the Rear Lot Conversion segment is the need to prudently manage safety risks to crews and the public. These risks are generally caused by the same operational factors and field conditions that contribute to long-duration outages on the rear lot system.

As mentioned above, as assets age and deteriorate, the risk of failure increases along with the likelihood that Toronto Hydro crews will need to access and repair rear lot equipment on a reactive basis. The congested nature and location of rear lot poles means that most cannot be accessed safely using bucket trucks. Workers must instead climb these poles, increasing the risk of potential injury from the additional physical exertion and falling hazard compared to when using a bucket truck, as well as an increased risk of electrical contact due to lack of bucket truck safety mechanisms (insulated aerial boom and bucket liner). Other potential safety risks associated with rear lot plant are:

- tight work spaces and reduced clearances for worker to operate equipment;
- poor visibility at night;
- poor footing in the winter;

- the need to manually transport equipment to poorly accessible job sites;
- the need to climb poles that may be in poor condition due to rot, animal damage, or other environmental factors and may require additional stabilization; and
- obstacles (e.g. fences, sheds, and swimming pools) and clearances between Toronto Hydro's distribution equipment and customer property that do not meet minimum requirements.

An incident demonstrating these safety risks occurred in 2014. Toronto Hydro dispatched a two-member crew following notification of a fallen tree at the rear of a house that had a steep slope covered with snow and ice. One crew member walked up the slope to locate the cable attachment and slipped and injured his right elbow and hip. The following pictures (Figure 7) show similar examples of safety challenges faced by Toronto Hydro crews.

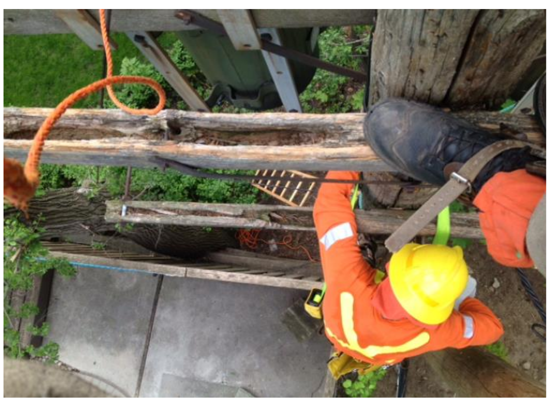


Figure 7a: Field crews replacing failed transformer on pole in poor condition

Figure 7b: Poor condition pole in close proximity to swimming pool

In addition to access issues, mature tree canopy cover (which sometimes requires immediate trimming on site) and poorly constructed landscapes can cause visibility issues in rear lots. Other than contributing to extended outage durations, reduced visibility is a safety concern for crews executing electrical work in locations that do not comply with (e.g. clearances defined in) the Electrical Utilities Safety Rules ("EUSR") rule 129, and applicable standards of the Canadian Standards Association ("CSA"), Toronto Hydro, and the Electrical Safety Authority ("ESA") (e.g. ESA Rule 75-708). The need to manage crew safety risk is one of the primary reasons that Toronto Hydro needs to minimize the aggregate risk of rear lot asset failure.

Public safety is also a key consideration in respect of the Rear Lot Conversion segment. Rear lot assets installed in the 1960s do not adequately account for access needs related to modern growth of neighbourhoods, expansions of homes and live line clearances. Locations have been identified where live wires are in close proximity to customer homes, sheds, fences, and swimming pools. Exposed wires have also been found at riser poles that have been deteriorating or moved over time due to direct contact. Furthermore, when a pole deteriorates or leans, a transformer leaks oil or catches fire, or porcelain insulators break, the safety risk to the public increases when installations are in proximity to those structures. Figures 8 and 9 illustrate some of these issues.

Limits of Approach

1. Rear lot overhead poles, transformers, and live conductors in close proximity to physical properties
2. Obsolete 4.16kV transformers
3. Aged and tilted cross arms and leaning poles
4. Mature vegetation. trees and vines present risk of contact
5. Transformers are typically mounted lower on the poles, in line with windows. If a transformer were to catastrophically fail it may be a hazard to the public or protrude into windows

Figure 8: Energized transformer and pole line close to home and covered in vegetation

Figure 9: Primary conductor and assets near swimming pools

3. Other Rear Lot Issues

The majority of feeders with rear lot areas are operating at 4.16 kV. Toronto Hydro is gradually converting all of these feeders to the standard 27.6 kV and rear lot conversion is an important component of this plan. In many cases, the rear lot area of a feeder must be converted before any other renewal conversion is possible, therefore it essential that the rear lot conversion is paced at a sufficiently rapid rate to enable conversions.

In addition to enabling the introduction of fault detection and isolation technologies like SCADA-mate switches, which are lacking on 4.16 kV feeders, converting to 27.6 kV is expected to:

- enhance power quality with less voltage drop for customers at the end of distribution lines;
- reduce line losses, improving the efficiency of the distribution system;
- modernize the system in order to prepare for the demands of electrification, growth, and the proliferation of distributed energy resources ("DERs") that 4.16 kV feeders cannot accommodate; and
- enable the eventual decommissioning of Municipal Stations, avoiding operating and maintenance expenditures that would otherwise be incurred.

Box Construction Conversion

The Box Construction Conversion segment is a continuation of Toronto Hydro's plan to convert functionally obsolete 4.16 kV feeders with box-framed poles to the latest standard 13.8 kV armless construction. Box construction is a legacy 4.16 kV overhead design. Due to safety, reliability, access, equipment, capacity, and procurement issues, Toronto Hydro no longer builds the system to this standard. As discussed in detail below, safety compliance issues drive the need to eliminate box construction from the system as quickly as practical. Figure 10 below shows the prior, during, and post-construction pictures of two converted box construction locations on Gerrard Street East.

Figure 10: Actual box construction conversion project on Gerrard Street East at two locations. Photographs on the left show 4.16 kV box construction poles prior to conversion. Photographs in the middle are demonstrating the in-construction stage. The completed project is shown in the photographs on the right, where all 4.16 kV box construction has been removed.

4. Box Construction Safety Issues

The industry-wide practice for overhead pole maintenance is to access circuits using bucket trucks. However, the congested nature of obsolete box construction design means that most box construction circuits cannot be accessed safely in this manner. Instead, workers must climb these poles, which increases the safety risks they face. Such risks include potential injury from the additional physical exertion from climbing, an elevated falling hazard when compared to the use of a bucket truck, and an increased risk of electrical contact due to the inability to use the insulated aerial boom and bucket liner found on the bucket trucks.

Furthermore, Toronto Hydro crews working in close proximity to box construction lines can have difficulty conforming to the working clearances defined in EUSR Rule 129.[4] The required 15-centimeter air gap between people (or tools) and energized conductors cannot always be achieved. Compliance with these safety rules requires adjustments to normal work operations, such as maneuvering around poles in a bucket truck and closing off road access to multiple poles. This in turn contributes to the lengthy outage restoration times discussed below.

Similar to rear lot lines, some box construction lines also fail to comply with applicable clearance requirements resulting in potential safety risks to the public. Live wires have been found in close proximity to customer homes, windows and balconies. Some buildings are within two to three metres of live lines due to the legacy design parameters of box construction. This issue must be addressed by replacing box construction with updated standard 13.8 kV construction as part of plant renewal. As a visual example, Figure 11 below illustrates some box construction clearance issues.

Limits of Approach

Box Construction poles house conductors with wide cross-arms which cause conductors to be spaced further away from poles and closer to buildings and windows compared to armless construction standards. This photo shows a few of the many issues associated with the obsolete design of box construction:

1. Close proximity of live lines to public and public structures due to the physical properties of the box frame.
2. Aged and tilted cross arms and leaning pole.
3. Transformers are typically mounted lower on the box poles, in line with windows. If transformers were to catastrophically fail, it may cause the windows to break and endanger the public.

Figure 11: Example of Box Construction clearance issues

5. Box Construction Reliability Issues

The existing box construction plant is on average 39 years old and is a poor reliability performer relative to the system as a whole. Despite a steady decrease in the total box construction plant

[4] Electric Utility Safety Rule 129 - safe limits of approach, Canadian Standards Association and Electrical Safety Authority, Page 34, "online", https://www.ihsa.ca/PDFs/Products/Id/RB-ELEC.pdf.

remaining over the last 10 years, there has not been a corresponding decrease in the total number of outages on box construction feeders (87 outages over 2013-2017 versus 88 over 2018-2022, excluding MEDs). The top causes of these outages include defective equipment, tree contacts, and adverse weather. Box construction assets are less capable of withstanding strong winds than new 13.8 kV overhead feeders in the downtown area as these assets are aging and deteriorating.

Box construction feeders also tend to require longer restoration times than feeders built to current standards, as shown in Figure 12. The reasons are similar to those that result in longer outages in the rear lot, including: the need for manual fault location; clearance, access and safety issues that slow down operations; and during reactive equipment replacement, the need to integrate newer standard equipment in a unique configuration that is compatible with the existing box construction design.

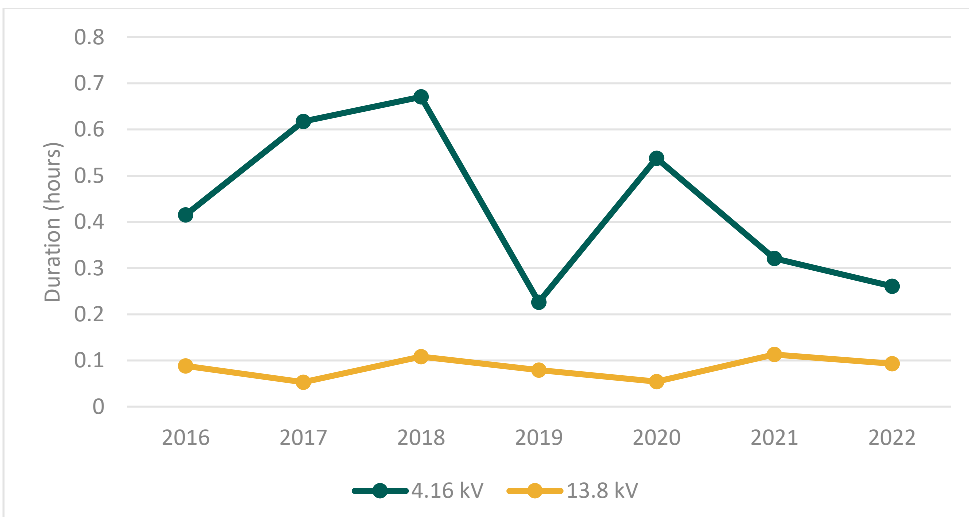


Figure 12: Average Outage Duration per Customer for 4.16 kV (Box Construction) and 13.8 kV Systems Excluding MEDs

Toronto Hydro expects reliability to worsen further as assets continue to deteriorate. Table 7 below shows the percentages of conductors, poles and switches that have already reached or exceeded their useful life. While the proportion of poles at or past useful life is fairly modest at 13 percent (as of 2022), by the end of 2023 another 17 percent will have also reached useful life. Furthermore, when considering the subset of poles that pose the most risk – i.e. those that are box framed – the percent at or past useful life has already reached 60 percent.

Table 7: Percentage of Box Construction Assets at or Past Useful Life

Asset Type	Percentage (%)
Overhead Primary Conductors	56%
Switches	36%
Poles	13%
Secondary Conductors	<1%

Based on asset condition assessment, 9 percent of the wood poles have material deterioration and are in poor condition and this percentage is expected to increase to approximately 35 percent by 2029 without any investments. As with age, when considering box-framed poles on their own, these percentages increase: to 15 percent HI4 or HI5 as of 2022 and 61 percent by 2029 (without investment).

Table 8: Condition Assessment of Box Construction Assets

Asset Class: Wood Poles	% of Assets per Class (2022)	% of Assets per Class (2029)
HI1 – Good Condition	60%	42%
HI2 – Minor Deterioration	5%	18%
HI3 – Moderate Deterioration	26%	4%
HI4 – Material Deterioration	8%	27%
HI5 – End of Life	1%	8%

6. Other Box Construction Issues: Capacity, Efficiency and Grid Modernization

Box construction feeders are part of the 4.16 kV legacy system. Crew members with expertise in legacy assets are needed to trouble shoot and address defective equipment when needed. The inability to acquire legacy assets often force them to repair the system using temporary and non-standard solutions. Workforce retirements are diminishing the pool of employees who are experienced in trouble shooting and repairing box construction feeders, which further underscores the need to eliminate box construction on a firm timeline.

Toronto Hydro is gradually phasing out 4.16 kV in favour of 13.8 kV and 27.6 kV standards. Lower voltage 4.16 kV feeders have significantly lower capacity and are less flexible in accommodating new loads than 13.8 kV feeders. Upgrading feeders to 13.8 kV system will allow Toronto Hydro to more efficiently accommodate new loads, renewable generation connections, and electric vehicle charging stations in high-growth areas of downtown Toronto. Without these upgrades, Toronto Hydro may need to connect new loads using alternative means, such as installing new feeders or extending existing feeders. This requires additional time and resources and may increase the connection costs for customers and developers. As noted above, upgrading feeders to a higher voltage will also reduce line losses and will help prepare the system for activities related to Grid Modernization (such as enhancing restoration capability of the system by adding switching points on the feeders and possibility of introducing self restoration schemes like Fault Location Isolation and Service Restoration ("FLISR")) which cannot be implemented on these legacy assets.

E6.1.4 Expenditure Plan

Table 9 below summarizes the historical, bridge and forecast spending for this Program. After examining program needs and establishing pacing strategies for each segment, Toronto Hydro developed the expenditure plan for the 2025-2029 rate period and applied volume and cost assumptions based on historical accomplishments. The cost estimates were created using the historical average cost per customer (for Rear Lot Conversion) and average cost per pole (for Box Construction Conversion) to extrapolate long-term program costs based on high-level project attributes. The forecast Rear Lot Conversion spending is higher over the 2025-2029 rate period when compared to 2020-2024 levels due to the deterioration of the assets in the rear lot areas due to age, as well as the need to modernize the system to enable growth and electrification. Toronto Hydro plans to eliminate all box-framed poles from the system by 2026 and continue converting the remaining box construction areas. The forecast spending is slightly lower compared to 2020-2024 levels due to the pace of work slowing as the utility gets closer to completing all box construction conversion.

Table 9: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Rear-Lot Conversion	9.2	9.9	12.8	18.3	11.7	19.8	21.2	23.4	28.5	27.7
Box Construction Conversion	26.5	29.6	21.0	19.6	49.1	44.5	39.9	10.2	10.6	10.9
Total	**35.6**	**39.5**	**33.8**	**37.9**	**60.8**	**64.4**	**61.1**	**33.6**	**39.0**	**38.6**

Rear Lot Conversion Expenditure Plan

Toronto Hydro invested $31.9 million in rear lot conversion projects between 2020 and 2022, resulting in the conversion of 384 customers from aging rear lot service to safer and more reliable front lot underground service. The utility plans to invest a total of $61.9 million by the end of 2024 to convert approximately 683 customers over the 2020-2024 rate period, a 71 percent reduction from Toronto Hydro's proposed conversion pace in the 2020-2024 DSP.

In accordance with the OEB Decision and Order on Toronto Hydro's 2020-2024 plan, which reduced the approved Rear Lot budget by $54 million to approximately $60 million, the utility significantly reduced its plan for Rear Lot Conversion and a number of projects (or project phases) and their corresponding customers conversions were deferred as shown in Table 10, below.[5] However, due to external pressures driving up costs and the significant reliability and safety risks associated with rear lot, especially during storm events and as assets continues to age and deteriorate, Toronto Hydro determined that it could not reasonably reduce the level of investment by the full amount prescribed by the OEB in its decision.

Table 10: Status of 2020-2024 DSP Planned Projects

Rear Lot Area	Phases	Number of Customers (2020-2024 DSP[6])	Number of Customers (updated)	Conversion Status
Thorncrest	Phase 9	618	89	Completed
	Phase 10		130	Completed
	Phase 11		114	2024
	Phase 12		147	Deferred
Jamestown	Phase 1	258	100	Completed
	Phase 2		62	Completed
	Phase 3		48	2023
Markland Woods	Phase 6	300	167	Deferred
	Phase 7		118	Deferred
Martin Grove Gardens	Phases 1 to 5	452	137	2024
	Phases 6 to 9		170	Deferred

[5] EB-2018-0165, Decision and Order (December 19, 2019) at page 93.
[6] Note that the number of customers in areas planned for 2020-2024 under the 2020-2024 DSP were high-level estimates and have since been updated based on more detailed information.

Mount Olive	Phases 1 to 3	83	61	Deferred
Kingsview	To be determined	173	156	Deferred
Richview Park	To be determined	263	263	Deferred
Willowridge	Phases 1 to 7	201	201	Deferred

Toronto Hydro plans to invest $120.6 million over the 2025-2029 rate period to convert approximately 1,467 rear lot customers in the worst performing areas to mitigate the various risks that have been discussed (including the risk of prolonged outages, ranging from 5 to more than 24 hours). Figure 13 shows the estimated rate of customers conversion from 2016 to the current estimated completion year of 2052.

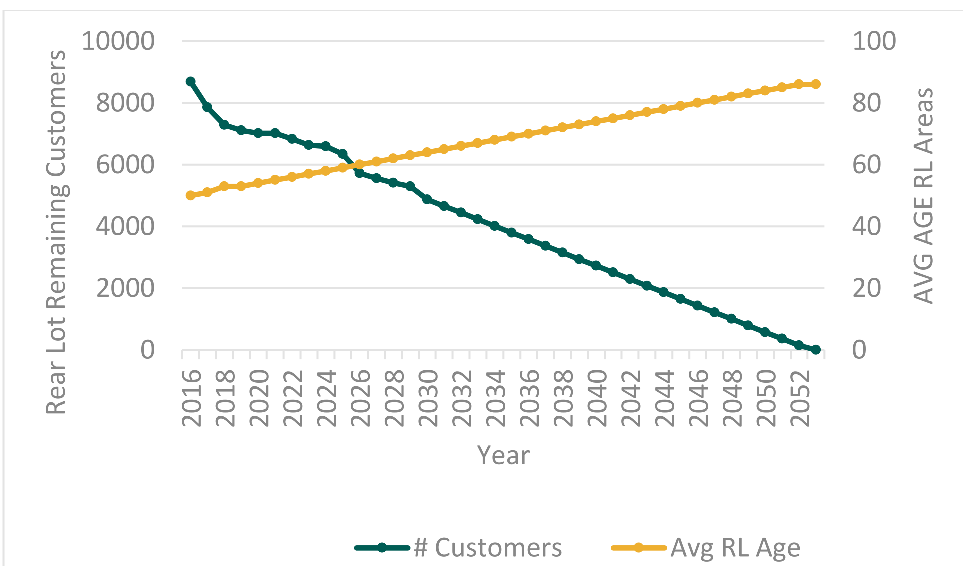


Figure 13: Rate of Conversion of Rear Lot Customers (2015-2029)

Rear Lot Conversion is not a like-for-like replacement activity. Projects are therefore difficult to estimate on an installed asset basis without first completing a preliminary design of the new front lot underground feeder, which does not take place until closer to project execution. As such, Toronto Hydro has used an historical average cost per customer to parametrically estimate 2025-2029 costs for the prioritized project areas. To develop the cost per customer, Toronto Hydro continued to use the methodology from the 2020-2024 DSP and examined two rear lot areas, consisting of four projects completed in recent years.

Toronto Hydro applied an average cost of $0.058 million per customer in developing the segment cost forecasts for the 2025-2029 rate period. This is a significant increase over the previous cost per customer estimated in the 2020-2024 DSP due to externally-driven escalations of labour, material, and other (e.g. vehicle) costs over recent years having a particularly high impact on the costs to plan and execute this complex conversion work.

The amount required per annum will vary year-over-year based on the timing of each project over multiple calendar years. Toronto Hydro designs and plans projects using a phased approach based on feeder configuration and customer count (e.g. Project Martin Grove Gardens with over 400 customers involved eight phases with multiple customers each) and ensures that civil construction is completed in one year and then followed in the next year by electrical construction. Civil work costs approximately twice as much as electrical and therefore annual costs (total and per customer conversion completed) will vary depending on the balance of civil and electrical work completed each year.

The average duration of a full 100-customer phase rear lot conversion construction project is approximately 24 months. By completing projects in a staggered fashion instead of addressing all the customers at one time, Toronto Hydro can improve reliability by reducing the time until the first customers will start benefitting from the conversion. For example, if Project Martin Grove Gardens were to be done as single-phase project it would take about 60 months for 400 customers to be fully converted and during that time all those customers would continue to experience a higher risk of outages on the legacy equipment. However, when done in phases, the first 50-70 customers would be converted after only 24 months. This way only a portion of the customers would be at higher risk of outages throughout the full project period. Minimizing the risk of outages minimizes the risk of added costs and long duration outages as crews can spend less time restoring power on legacy equipment.

Rear Lot Conversion projects are prioritized based on asset reliability, equipment condition, and coordination with planned city road work. Generally, the worst performing feeders are targeted for completion first, however rear lot areas where projects have started must be fully completed before moving to a new area despite any changes in reliability performance. To reduce costs, Toronto Hydro also strategically aligns and coordinates rear-lot projects with other conversion projects that share the same feeder. Figure 14 identifies rear lot areas, including those that Toronto Hydro has recently converted and those prioritized for conversion over 2025-2029, with additional details on latter areas in Table 10.

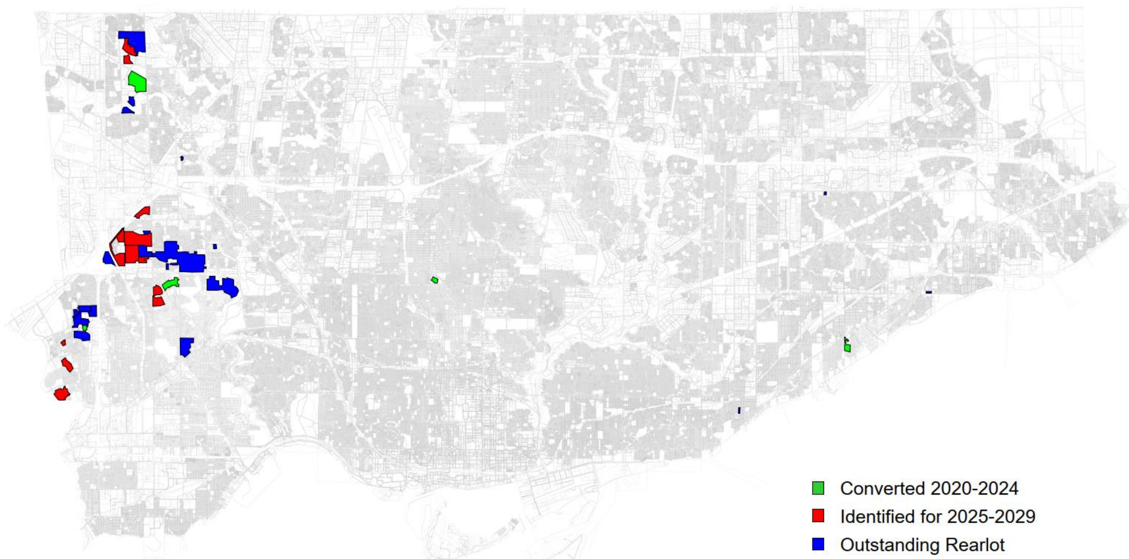


Figure 14: Outstanding Rear Lot Areas to be completed during 2025-2029 and beyond

Table 11: Planned Rear Lot Projects for 2025-2029

Rear Lot Area	Number of Customers	Expected Date of Completion	Number of Outages (2012-2022)	Number of Outages Greater than 5 Hours (2012-2022)
Thorncrest Phase 12	147	2025	1	0
Markland Woods	285	2025-2026	17	8
Martin Grove Gardens	307	2025-2027	7	2
Willowridge	201	2027-2028	11	3
Mount Olive	61	2027-2028	2	2
Kingsview	156	2028-2029	11	2
Eringate Centennial-West Deane	130	2028-2029	18	2
Richview Park	263	2028-2029	1	0

For the 2025-2029 rate period, Toronto Hydro has planned the conversion of seven rear lot areas, the majority of which the utility deferred from the 2020-2024 rate period as discussed above:

Thorncrest, Markland Woods, Martin Grove Gardens, Kingsview, Willowridge, Mount Olive and Richview Park. One new rear lot area is also planned for conversion towards the end of the rate period, which has been preliminarily identified as Eringate Centennial-West Deane, but may change based on the latest reliability data and any other considerations closer to the time of planning.

Box Construction Conversion Expenditure Plan

Toronto Hydro invested $77.0 million in Box Construction Conversion projects over 2020-2022, removing 444 box frames and converting a total of 1,889 poles to safer, more reliable, and operationally flexible 13.8 kV feeders. The utility plans to invest $68.7 million over 2023-2024 to eliminate approximately 236 additional box frames and convert 1,479 poles. This will leave approximately 344 box frames and an estimated total of 1,681 poles to be addressed in the 2025-2029 period. Toronto Hydro expects to spend about 36 percent ($38.4 million) more than the $107.3 million initially forecast for the 2020-2024 period. The cost variance is driven by changes to the project schedule, including a number of projects that carried over from the 2015-2019 rate period (as shown in Table 11 below), as project phases were deferred or moved up to accommodate internal and external dependencies. Other drivers include externally driven price escalations, coordination and accommodation of third-party initiatives such Metrolinx's Ontario Line and the City of Toronto's CafeTO, and the differences between high level estimates used for the forecasts and the detailed estimates and actual costs following detailed design and construction.

Table 12: Box Construction Projects 2020-2029

	Conversion	Construction Attainment	Projected/ Actual Costs ($M)[7]
Carlaw	2019-2021	Complete	7.3
Dupont	2018-2022	Complete	8.1
Danforth	2018-2024	2024	22.6
Hammersmith	2017-2021	Complete	14.1
Junction	2018-2022	Complete	11.3
Runnymede	2019-2021	Complete	5.0
Wiltshire[8]	2024	2024	0.3
Highlevel	2021-2026	2026	70.5

[7] Excludes inflation and other allocations.
[8] MS Decommissioning.

Sherbourne	2021-2026	2026	21.7
Spadina-Chaplin	2022-2026	2026	37.45
University	2021-2029	2029	25.1
Defoe-Strachan[9]	2017-2026	2026	21.0

Toronto Hydro estimates that $116.1 million will be required over the 2025-2029 rate period to complete full conversion of all except one (Defoe-Strachan, see footnote 8 below) of the remaining box construction areas, which will improve average outage restoration time for 15,246 customers. Other anticipated benefits of this work include (1) addressing safety risks related to EUSR, CSA and ESA compliance issues, (2) improving speed and cost-efficiency of customer grid access in high-growth areas of downtown Toronto, and (3) reduced traffic disruptions due to less frequent repairs and maintenance. Figure 15 below shows the actual and anticipated rate of removing box frames from the system. As discussed further below, Toronto Hydro must complete some conversion work after all the box-framed poles have been removed.

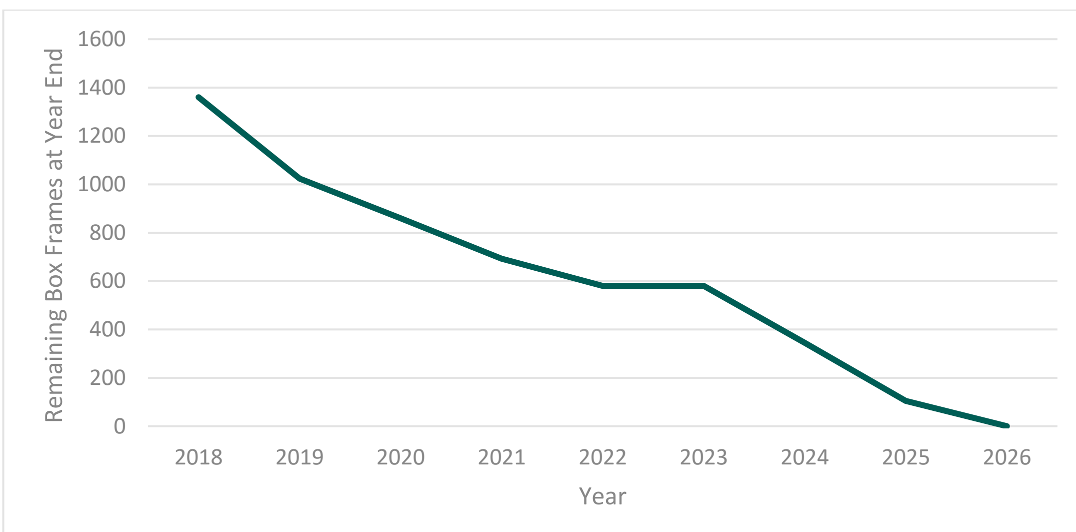


Figure 15: Remaining Box-Framed Poles in the System (2018-2026)

[9] For the Defoe-Strachan area, while all box-framed poles will be removed, full voltage conversion will not be completed until after 2029 due to a number of internal and external dependencies and those costs are not included in the table.

Toronto Hydro examined a number of completed box construction projects to develop an average cost of conversion per pole. This analysis concluded that cost of conversion fluctuates from one project to the next or from one year to other due to area specific characteristics. For example:

- Some areas have lessor number of poles but have coordination and execution challenges while other areas have higher concentration of poles but are relatively easier to construct.
- Some areas have overhead supply directly feeding customers on a quiet side street without trees and underground risers while other areas have box construction assets on a main downtown artery, such as Queen Street, with both primary and secondary distribution and risers going from overhead to underground and vice versa.
- Some areas may have road access issues, moratoriums, work time restrictions, heavy vegetation, or third-party attachments such as TTC street cars that require coordination while other areas may not have these issues.
- Some projects, based on their location and box construction framing density, require different techniques for the safe removal of the legacy equipment.

In order to minimize the cost fluctuations, Toronto Hydro established an average cost of $0.039 million per pole using various projects completed in 2018 to 2022. This average cost of conversion per pole was used to derive the forecast costs for projects for 2025-2026. The increase in this unit cost over the cost per pole in the 2020-2024 DSP reflects inflationary pressures and the fact that the last box construction areas to be completed are the most complex and challenging to design and execute.

Box construction projects planned for the 2025-2029 rate period will convert all remaining box construction on the system, except for part of the Defoe-Strachan area. These phases are interdependent, have to be coordinated with Hydro One, transit authorities including the TTC and Metrolinx, customer connection and third-party development projects, and have to be executed in a particular order. Therefore, Toronto Hydro will continue to manage to the current schedule, prioritizing removal of all remaining box-framed poles by the end of 2026 in alignment with the utility's previously established commitment to eliminate the public and employee safety risks associated with these poles. However, as discussed further in section E6.1.6.2, while it will remove all remaining box-framed poles by 2026, conversion work will be executed in two-phases with only partial voltage conversion at Defoe-Strachan and University completed by 2026. While Toronto Hydro expects to complete full conversion of University by the end of the 2025-2029 rate period, the remaining conversion for Defoe-Strachan cannot be continued until after 2029 due to a number of factors, including conflicts with Metrolinx's Ontario Line work.

E6.1.5 Options Analysis

Options for Rear-Lot Conversion

1. **Option 1: Continue Converting Rear Lot Customers at Current (2020-2024) Pace**

Under this option, Toronto Hydro would maintain the current pace of rear lot conversion over the 2025-2029 rate period. Areas not planned for conversion would continue to pose higher safety risk and be prone to prolonged outages, especially in extreme weather. It would also lead to more reactive replacements of assets, which tend to cost more and do not achieve any of the benefits, such as increased efficiencies and capacity to enable customers to connect new services, related to converting to 27.6 kV. At this pace, it would take until the mid 2050s to convert all remaining rear lot customers, at which point the reliability impact on customers and safety risk would be completely unacceptable given the extreme age and expected deterioration of the remaining assets. Given the current age and condition of these assets, the current pace of conversion is not sustainable and would require a much higher level of investment beyond 2029 to mitigate the increasing risk and deteriorating performance. Especially in light of recent customer feedback that indicates that timely restoration during extreme weather events is a top priority, this option is not recommended.

2. **Option 2 (Selected Option): Convert Rear Lot Customers at Moderately Increased Pace**

Under this option, Toronto Hydro plans to moderately increase its pace of rear lot conversion in the 2025-2029 rate period. This will support mitigation of safety risks and reduce the frequency of prolonged outages, as well as support modernization of the grid through voltage conversion. At this pace, it will still take until after 2050 to convert all rear lot customers and the remaining rear lot areas will continue to pose increasing reliability and safety risks. Toronto Hydro also expects that it will need to increase the pace of investment beyond 2029 to address this escalating risk as these assets age and deteriorate, but not as dramatically as it would need to under Option 1. Toronto Hydro finds this option to be a reasonable balance between residential customers' top two priorities of price and reliability.

3. Option 3: Convert Rear Lot Customers at Accelerated Pace

Under this option, Toronto Hydro would further increase the pace of rear lot conversion over the 2025-2029 rate period. At this pace, Toronto Hydro would eliminate all rear lot plant and its associated risk by the mid 2040s. This would also enable faster progress in converting the system to 27.6 kV and realizing the associated benefits, including lower costs associated with maintaining and renewing municipal stations and improved service levels for customers connecting new services or choosing new technologies such as solar panels. This is the best option for managing rear lot risk and standardizing the grid, but the additional cost cannot be justified at this time given Toronto Hydro's other investment priorities and the need to limit rate increases.

Options for Box Construction Conversion

1. Option 1: Full Voltage Conversion and Box-Framed Pole Removal beyond 2026

In this scenario, Toronto Hydro would delay the removal of the last box-framed poles from the system beyond 2026, when it could be incorporated into full voltage conversion projects. Station constraints (see section E6.1.6.2 for more detail) and other considerations have resulted in certain areas being unfeasible to fully convert to 13.8 kV by the end of 2026 as previously planned. Delaying the removal of some box-framed poles beyond 2026 presents unacceptably high safety risks to Toronto Hydro employees. The utility is committed to meeting its previously established 2026 target for box-framed pole removal. Therefore, this option is not recommended.

2. Option 2 (Selected Option): Removal of Remaining Box-Framed Poles by 2026

This option will eliminate the significant safety risks associated with box construction assets for crews and the public by the end of 2026. It will also remove capacity constraints, renew aging and deteriorating assets, improve reliability for customers, and enable the retirement of station assets that will be otherwise costly to renew or maintain. This option involves removing all box-framed poles by the established deadline of 2026, but full voltage conversion and station decommissioning for two areas will be completed later due to station constraints.

This option is recommended as it enables the fastest possible elimination of the safety risks associated with box-framed poles, while providing short and long-term benefits to customers and the utility.

E6.1.6 Execution Risks & Mitigation

Rear-Lot Conversion

Timely third-party project coordination: One program risk is the potential for a minimum five-year moratorium on new road work in areas where Toronto Hydro intends to do rear lot conversion work. Toronto Hydro will mitigate this risk by working closely with the City of Toronto on planned road work (i.e. through utility coordination council meetings). In the event that planned City of Toronto work puts program completion at risk, Toronto Hydro will negotiate with the city to coordinate a construction schedule that is acceptable to all parties and stakeholders involved.

Customer Engagement: Customer care is a significant aspect of risk mitigation during the planning and execution phases of rear lot conversion, which by nature are relatively intrusive and involve construction on multiple sides of each customer property. To determine asset locations that best align to customer preferences, Toronto Hydro maintains extensive and proactive customer communication and provides an opportunity for customers to voice their concerns and to work with the designer and constructor. In most cases, community meetings are held to proactively introduce residents to the project plans and educate them on construction implementation. City Ward councillors are informed of the project and often are invited to community meetings and pre-construction meetings to assist with constituent inquiries. Written letters are sent in advance to customers' homes to inform them of the project, new equipment installations and line of sight to new equipment as per applicable municipal notice requirements.

Conversion coordination: The remaining rear lot configurations feature multiple feeders that provide service across the same easement, making conversion activities relatively complex. These feeders depend on one another for load transfers, especially during contingency scenarios (i.e. during outages on any of the feeders). Feeders tie with one another and can be used to resupply each other if a feeder's primary source of power from a substation is disrupted due to a fault or work being done. Therefore, it is important that alternative sources of power remain available during conversion in the event of an emergency. These interconnections require careful staging of conversion jobs over several years.

Box Construction Conversion

Station Constraints: In order to do the voltage conversion work, affected 13.8 kV stations need to have spare cell positions and 4 wire capability. If these are lacking in an area, Toronto Hydro works with stakeholders to implement them where needed. However, this can take time and may be dependent on external factors, such as Hydro One work. For two of the remaining box construction areas, Defoe-Strachan and University, this is an issue that Toronto Hydro cannot address in time to complete full box construction conversion of these areas by 2026 as was previously intended. Therefore, Toronto Hydro's strategy in these areas is to perform box-framed pole removals with and without voltage conversion, i.e. partial conversion of these areas. Where feasible, Toronto Hydro will rebuild portions of the feeders to remove box-framed poles while the system remains energized at 4.16 kV, with a provision to add 13.8 kV lines on the renewed poles in the future, once constraints are resolved. For the remaining box-framed poles that cannot be removed without conversion, the utility will transfer load to open up a few cell positions and enable some voltage conversion.[10]

Project Interdependencies: Projects in this segment have highly interdependent phases that have to be executed in a particular order. Delays in any particular phase cascade to the later phases of the project. In order to remove box frames within the established timeline, Toronto Hydro regularly reviews the execution plan to identify and resolve any emerging issues.

Customer Coordination: For the majority of the commercial customers serviced on 4.16 kV system, there is underground equipment, risers, and terminations connected to the pole. Transferring a riser and termination requires an outage to the customer to conduct work safely. Coordinating power interruptions and access with customers could delay projects. Toronto Hydro is mitigating this risk through proactive and early customer engagement.

Construction Coordination: Many of the remaining box construction assets are within high pedestrian and vehicle traffic areas which also include TTC bus or streetcar routes (see example shown in Figure 16). In this regard, mitigation involves proactive coordination and engagement with the City to create a traffic plan, especially at major intersections. Most pole installations require a single lane to be occupied by trucks and equipment and as such, inadequate coordination would jeopardize project completion in a timely manner.

[10] Note that some of this load transfer relies on energization of Copeland Station (Phase 2).

Figure 16: Area with High Pedestrian and Vehicle Traffic, including TTC Routes.

Third-Party Assets: Third-party assets attached to the utility poles, such as Rogers, Bell, and City assets, can interfere with full conversion and pole removal work. Toronto Hydro will engage owners of these assets as soon as possible to coordinate and plan their transfer to avoid delays.

E6.2 Underground System Renewal – Horseshoe

E6.2.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 359.8	**2025-2029 Cost ($M):** 475.7
Segments: Underground System Renewal Horseshoe	
Trigger Driver: Failure Risk	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Environment	

The Underground System Renewal – Horseshoe program ("the Program") manages failure risk on major underground distribution assets serving customers in the Horseshoe area of Toronto. The Program invests in proactive asset renewal and focuses on maintaining the reliability, safety, and environmental risk levels of major underground distribution assets. This program is a continuation of the activities described in the Underground System Renewal – Horseshoe program in Toronto Hydro's 2020-2024 Distribution System Plan ("DSP").[1]

The Program addresses three major underground asset classes: cables, transformers, and switches. These assets deteriorate over time due to usage, aging, and exposure to harsh environments which increases the risk of failure. Legacy asset design issues exacerbate the probability of failure for certain asset types targeted by this program.

Outages caused by asset failure on the underground system take approximately 34 percent longer to restore than outages on the overhead system, resulting in lengthy interruptions that may last up to 24 hours or longer. The failure characteristics of legacy underground cables are such that customers can experience multiple cable-related outages in a short period, leading to potentially significant declines in customer satisfaction in affected neighborhoods.

The program consists of both rebuild and spot replacement projects. Rebuild projects are ideal when a confluence of conditions within a concentrated geographical area make it necessary and/or economically prudent to rebuild an entire section of the system. For example, areas of the system with a high concentration of assets at risk of failure (e.g. due to deteriorated condition) and a history of poor reliability are typically addressed through rebuild projects. Voltage conversion is another

[1] EB-2018-0165, Exhibit 2B, Section E6.2

important consideration for rebuilds. For example, Toronto Hydro has a population of legacy 4.16 kV feeders in the Horseshoe that it is gradually converting to modernized 27.6 kV standards in order to improve operational performance and efficiency and prepare for the demands of electrification, growth, and the proliferation of distributed energy resources ("DERs"). As 4.16 kV is no longer an accepted system standard, when 4.16 kV asset condition and performance within an area deteriorate, Toronto Hydro will generally rebuild the area to current standards rather than replace individual assets on a like-for-like basis.

The Program's investments in the three major underground asset classes are summarized as follows:

- **Cables**: Cables are the greatest contributor to outages caused by defective equipment on Toronto Hydro's system in the Horseshoe, resulting on average in 146,000 customer hours of interruption per year. Through prioritized neighbourhood rebuild projects focused on replacement of high-risk direct-buried cross-linked polyethylene ("XLPE") cables, Toronto Hydro previously had success reducing the number of customer interruptions due to cable failure, from over 200,000 per year in 2013 to approximately 105,000 in 2019. However, more recently Toronto Hydro shifted focus away from rebuild projects addressing direct-buried cables in order to address the urgent environmental risk associated with PCBs. As a result, customer interruptions (and other reliability indicators) have started trending back up, reaching 199,000 in 2022. As of 2022, there are 666 circuit-kilometres of direct-buried cable in the underground system, of which 286 circuit-kilometres are direct-buried cable in dirt, and 380 circuit-kilometres are direct-buried cable in PVC ducts. While direct-buried XLPE cable (not in duct) was previously considered the highest failure risk, direct-buried cable in PVC ducts is now also a priority as it can get clogged with dirt and get sheared due to the movement of earth, making it difficult to replace the cable inside the PVC duct. Toronto Hydro expects the entire direct-buried cable population to be a significant source of failure risk and driver of reliability outcomes as the cables continue to age over the 2025-2029 period. Over half of this cable has reached or passed its useful life as of 2022. Toronto Hydro plans to replace an estimated 340 circuit-kilometers of underground cable, including 182 circuit-kilometres of direct-buried cable over the 2025-2029 period to maintain current average reliability performance on the underground system and to help sustain improvements in the number of feeders experiencing seven or more interruptions per year ("FESI-7").

- **Transformers:** Underground transformers are typically exposed to harsh environmental conditions, and defective transformers cause approximately 17,700 hours of customer interruption per year and contribute to 21 percent of failures on the underground system. As of 2022, 26 percent of underground transformers have reached or surpassed useful life, and over 600 units have at least material deterioration. Without proactive investment, Toronto Hydro expects the number of units past useful life to increase to 39 percent (over 10,000 units) and the number with at least material deterioration to increase to 2,400 by 2029. Toronto Hydro replaces aging and deteriorated underground transformers proactively as part of rebuild projects, and will continue to do so in the 2025-2029 period. Over the 2020-2024 period, Toronto Hydro has shifted towards doing more spot replacements to support the utility's objective of reducing the number of potentially high-consequence PCB leaks. In 2025, Toronto Hydro plans to continue the replacement of the remaining underground transformers that are known to contain, or are at risk of containing, PCB-contaminated oil. Over 2026-2029, the utility will shift back towards a more rebuild-focused approach, using spot replacements for only the worst condition transformers not addressed through rebuilds. Overall, the utility plans to replace an estimated 2,478 underground transformers during the 2025-2029 period through a combination of area rebuilds and spot replacement, with the objective of maintaining average system reliability, eliminating the risk of PCB leaks, and supporting long-term risk management of the underground transformer population.

- **Switches**: Underground switches are continuously exposed to harsh environmental conditions, and their failure typically leads to prolonged outages, ranging from approximately two to 35 hours, affecting an average of 1,350 customers at a time. On average, switches have contributed to approximately 20,000 hours of customer interruption annually. Failure of these assets can also pose employee and public safety risks due to the potential for arc flashing, a risk that is higher with Toronto Hydro's remaining population of legacy air-insulated switches. The number of air-insulated padmounted switches in end-of-serviceable life condition ("HI5") is anticipated to rise from 29 in 2022 to 104 by 2029, which aligns with the accelerated rate of degradation that Toronto Hydro has seen for this type of switch in the field.[2] During the 2025-2029 period, the utility plans to proactively replace an estimated 116 underground padmounted switches in conjunction with area rebuild projects,

[2] Over 90 percent of the failed switches that the utility analyzed in the last five years failed prior to reaching their expected useful life of 40 years, with the highest rate of failure occurring in the 10-14 years range.)

prioritizing higher-risk air-insulated switches operating beyond useful life and/or exhibiting material degradation.

Toronto Hydro plans to invest $475.7 million in the Underground System Renewal program in 2025-2029, which is a 32 percent increase over projected 2020-2024 spending in this Program (including forecasted inflation). This pace of investment is necessary to maintain current average reliability on the underground system, sustain improvements in the number of feeders experiencing seven or more interruptions a year, and prevent asset-related risk on the underground system from increasing in an unsustainable manner over the long-term.

E6.2.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's objectives and obligations to connect low and high voltage customers within 5 and 10 business days respectively at least 90 percent of the time (pursuant to the OEB's new connection metrics and section 7.2 of the Distribution System Code ("DSC"), by upgrading 106 circuit kilometres of low capacity 4.16 kV or 13.8 kV distribution lines to higher voltage capacity of 27.6 kV distribution lines.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, Direct Buried Cable replacement measure) by ○ Replacing approximately 340 circuit-kilometers of underground cable that includes 182 circuit-kilometres of direct buried underground cable that poses elevated risks to reliability; and ○ Replacing assets at and beyond useful life or showing signs of at least material deterioration (i.e. HI4 and HI5) at the end of 2029[3]

[3] For many of its major assets, Toronto Hydro performs asset condition assessment ("ACA"), in which the condition of each asset is assigned a health index ("HI") band from HI1 to HI5, where HI5 indicates the worst condition. For these same assets, the utility can then also project future condition (i.e. HI band) assuming no intervention. See Exhibit 2B, Section D, Appendix A for more details on Toronto Hydro's ACA methodology

Environment	• Contributes to improving Toronto Hydro's performance in relation to the Spills of Oil Containing PCBs measure, and reducing the environmental impact and risks associated with Toronto Hydro's distribution system by removing the remaining underground assets at or beyond useful life that contain or are at risk of containing PCBs by 2025, pursuant to PCB regulations (PCB Regulations[4] made under the Canadian Environmental Protection Act, 1999[5], the Environmental Protection Act[6] and the City of Toronto's Sewer Use By-Law[7])

E6.2.3 Drivers and Need

Table 3: Drivers and Need

Trigger Driver	Failure Risk
Secondary Driver(s)	Environmental Risk, Safety, Reliability, Capacity Constraints/Growth

The Underground System Renewal – Horseshoe program focuses on replacing three types of assets: cables, transformers, and switches. These assets are the primary components of the underground distribution system, and will typically be replaced in accordance with current standards, generally on a like-for-like basis, unless part of a voltage conversion project.

The proposed renewal is driven by the risk and impacts of asset failures on system reliability, the environment, and public and employee safety. These risks are primarily due to two factors. The first is accelerated degradation of asset condition due to exposure to external elements, such as dirt, salt, dust, moisture, and humidity. This contributes to a loss of integrity of the physical asset, which can in turn lead to failure. Secondly, assets that are at or approaching their end of useful life have a higher probability of failure.

Table 4 provides the useful life of the underground assets in the Horseshoe area. Asset failures may lead to: (1) reliability risks, which can cause outages and directly impact customers; (2) environmental risks, such as oil spills (which may contain PCBs) that harm the environment; and (3) safety risks, resulting from arcing and catastrophic failures.

[4] SOR/2008-273
[5] SC 1999, c. 33
[6] RSO 1990, c. E.19
[7] City of Toronto, by-law No 681, Sewers, (May 15, 2023).

Table 4: Useful Life of Underground Assets by Type in the Horseshoe

<table>
<tr><th colspan="2">Type</th><th>Useful Life (Years)</th></tr>
<tr><td rowspan="2">Direct Buried Cable</td><td>Installed in PVC Duct</td><td>40</td></tr>
<tr><td>Not Installed in PVC Duct</td><td>20</td></tr>
<tr><td colspan="2">Cable in Concrete Encased Duct</td><td>50</td></tr>
<tr><td rowspan="3">Transformers</td><td>Submersible</td><td rowspan="3">30</td></tr>
<tr><td>Padmounted</td></tr>
<tr><td>Building Vault</td></tr>
<tr><td rowspan="2">Switches</td><td>Padmounted</td><td rowspan="2">40</td></tr>
<tr><td>Vault</td></tr>
</table>

The number of outages due to underground defective equipment has been a major contributor to overall system outages over the last 10 years, constituting almost 56 percent as shown in Figure 1. Historical investments in the Program have driven some reduction in outages due to underground defective equipment, reaching a low in 2019, but this has since started trending up again. A similar pattern has emerged for Customers Interrupted (“CI”) and Customers Hours Interrupted (“CHI”), which indicate the impact of these outages on customers, as shown in Figures 2 and 3. This recent deterioration in underground defective equipment driven reliability is largely driven by cable-related outages and is at least partly attributed to Toronto Hydro’s prioritization of the removal of PCB at-risk underground transformers during the current rate period. This has shifted work in the Program towards more spot replacements of transformers based on PCB-risk and away from direct-buried cable renewal. As the remaining PCB at-risk transformers are removed from the system, Toronto Hydro plans to shift back to a more balanced distribution of work that will better mitigate reliability risk.

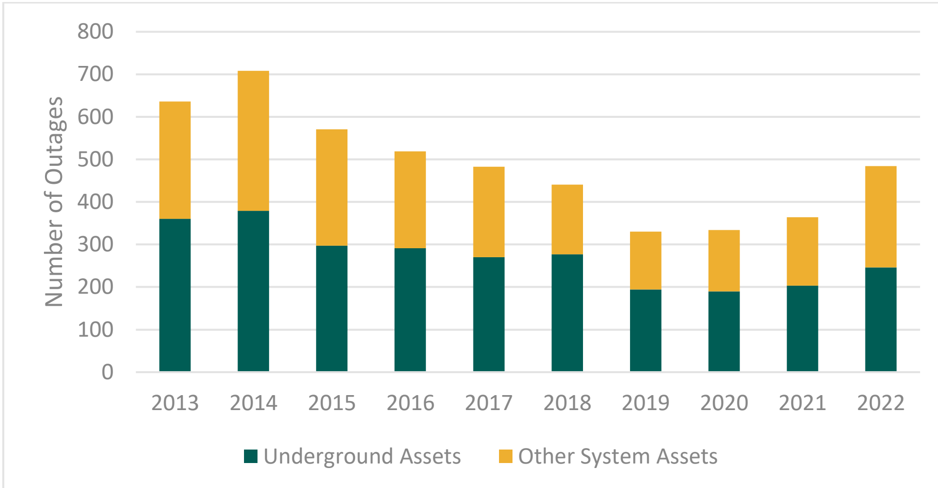


Figure 1: Ten-year Trend of Underground System Contribution to Overall System Outages

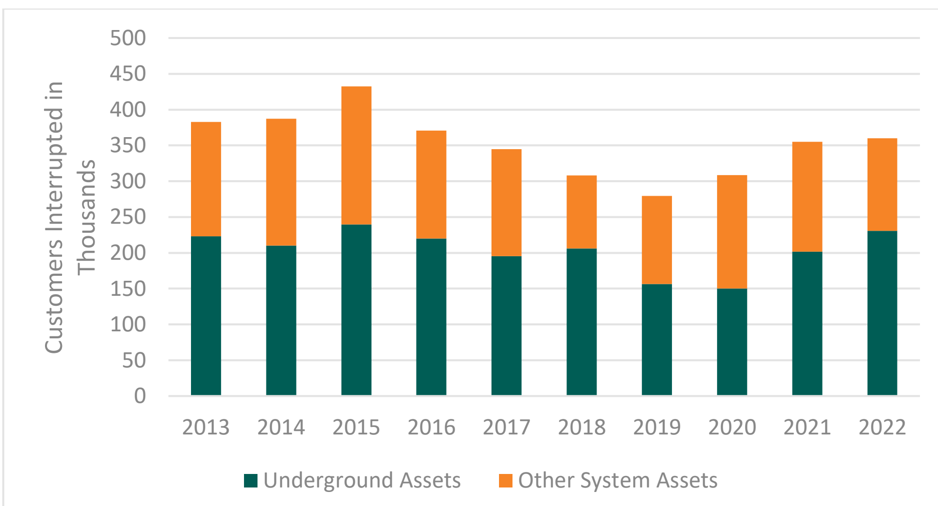


Figure 2: Ten-year Trend of Underground System Contribution to Overall System Customers Interrupted ("CI")

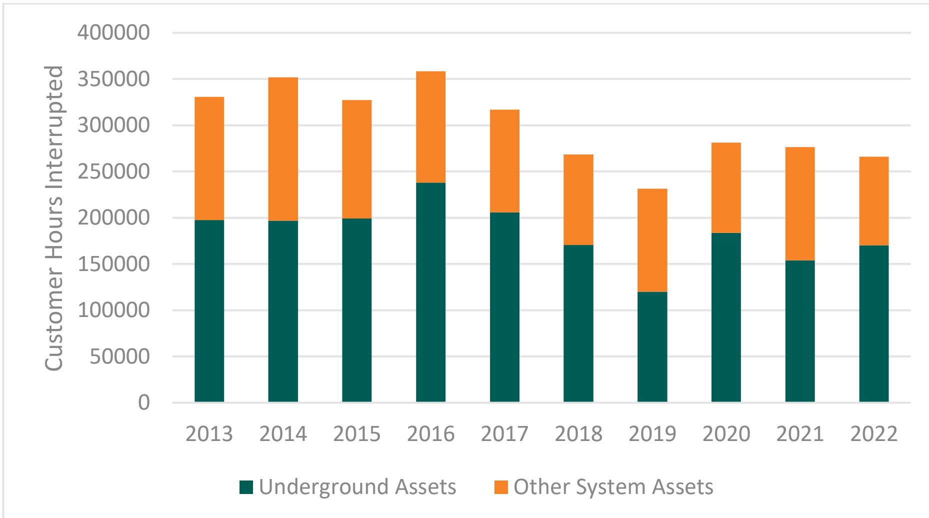


Figure 3: Ten-year Trend of Underground System Contribution to Overall System Customer Hours Interrupted (CHI)

While historical investments improved underground reliability in the Horseshoe area over 2015-2019, performance has started to backslide more recently and Toronto Hydro must increase the pace of renewal to prevent further deterioration. A significant number of assets (e.g. cables) are already past their useful life as of 2022 and the population continues to age. This increases the risk of failure, requiring Toronto Hydro to reactively replace faulted underground equipment. In general, underground assets are more difficult to replace compared to those in the overhead system, mainly because they are installed below-grade and not readily visible or accessible for fault locating.

When an underground fault occurs, controllers first check SCADA devices to determine which section of the feeder is affected. Next, crews look at fault indicators installed on various points on a feeder to locate the component that has faulted, a process that can take hours. Fault locating of direct buried cable is particularly challenging, as crews first need to perform tests to identify the general location of a fault, then dig up that location to confirm and pinpoint the actual cable fault. In some cases, crews need to dig multiple pits to identify the exact location before they can make repairs, prolonging the outage and inconveniencing customers. Operational outages to repair these assets can also expand the outage to surrounding areas thus affecting more customers.

Additionally, the nature of the work leads to significant unplanned disruptions and inconveniences for the neighbourhood and community as a whole, and often requires last minute coordination with third parties under emergency situations and tight timelines. For underground assets, this is particularly difficult where customers own the assets (such as vaults), as coordination can delay the repair work and extend the outage. In contrast, proactive replacement allows Toronto Hydro to coordinate work with third parties well ahead of the scheduled repair work.

Through a combination of spot replacements and complete rebuilds of areas with poor reliability and large concentrations of high-risk assets, Toronto Hydro plans to replace approximately 340 circuit-kilometers of underground cable, 2,478 underground transformers, and 116 switches over the 2025-2029 period.

Outages on assets at 4.16 kV and 13.8 kV voltages continue to be responsible for a significant number of outages despite more than a decade of work converting to 27.6 kV. In 2013, areas fed by 4.16 kV and 13.8 kV feeders contributed to over 35 percent of the total outages on the underground system and this has increased to over 43 percent on average over the last five years (2018-2022). Any targeted underground areas that still utilize 4.16 kV or 13.8 kV systems will be converted to 27.6 kV. These are legacy assets which cannot be easily replaced and their configurations do not allow for expansion and provide limited options for system restoration during contingency. The overhead portion of these feeders are addressed by the Overhead Renewal program as well as the Area Conversions program.[8] Converting to 27.6 kV is expected to:

- enhance power quality with less voltage drop for customers at the end of distribution lines;
- reduce line losses, improving the efficiency of the distribution system;
- modernize the system in order to prepare for the demands of electrification, growth, and the proliferation of DERs that 4kV cannot accommodate; and,
- enable the eventual decommissioning of Municipal Stations, avoiding operating and maintenance expenditures that would otherwise be incurred.

There are approximately 170 4.16 kV and 13.8 kV feeders remaining to be converted throughout both the underground and overhead system in the Horseshoe. Toronto Hydro is planning to convert both the overhead portion and the underground portion of 29 of these feeders by 2029. At this pacing Toronto Hydro expects it could complete the underground voltage conversion portion of the entire system by 2055-2060.

[8] Exhibit 2B, Section E6.5; Exhibit 2B, Section E6.1.

E6.2.3.1 Replacement of Underground Cable

Toronto Hydro plans to replace underground cable that is past its useful life along with high-risk direct-buried cable that causes poor reliability in the Horseshoe area.

Generally, two types of cables exist in the Horseshoe underground distribution system: (i) XLPE; and (ii) tree-retardant cross-linked polyethylene ("TRXLPE"). These can be installed in three ways: (i) direct buried; (ii) in direct-buried Polyvinyl Chloride ("PVC") ducts; or (iii) in concrete-encased ducts. The majority of direct-buried XLPE cables in Toronto Hydro's system were installed before 1990 and were fabricated using manufacturing processes that are now considered inferior. These assets were installed using a legacy type of construction methodology where cables were laid directly in underground trenches without a protective barrier.

These cables are susceptible to outages due to direct exposure to environmental conditions. Moisture is the most destructive element that affects direct-buried XLPE cable. Water ingress into the cable insulation in the presence of an electrical field causes microscopic tears called "water treeing". Over time, continued moisture penetration and the presence of electrical stresses causes these water trees to become electrical trees (whereby the tears become carbonized and can conduct electricity). This causes the cable to internally short circuit and fail.[9] Additionally, direct-buried XLPE cables in PVC ducts can get clogged with dirt and get sheared by the movement of earth or other external factors, making it difficult to replace the cable inside the PVC duct as shown in Figure 4 below.

Based on Toronto Hydro's experience with direct buried cables, following an initial failure (which is typically a sign of deteriorated insulation and electrical and thermal stresses along the entire segment), subsequent failures in the cable segment occur with greater frequency. Additionally, voltage stress applied to the cable during the fault locating process further degrades the cable insulation.

[9] Exhibit 2B, Section D2 for more details

Figure 4: Clogged PVC Ducts

Underground cable system failures that include underground cables, terminations, and other cable accessories account for approximately 73 percent of the defective equipment-related outages in the underground Horseshoe system as shown in Figure 5 below. The ten-year reliability impact of the underground cable system discussed in this Program is shown in Figures 6 to 8. After reaching a low (improved reliability performance) in 2019, the reliability impact of underground cable systems has started to trend higher again and proactive replacement of underground cable systems is required from 2025-2029.

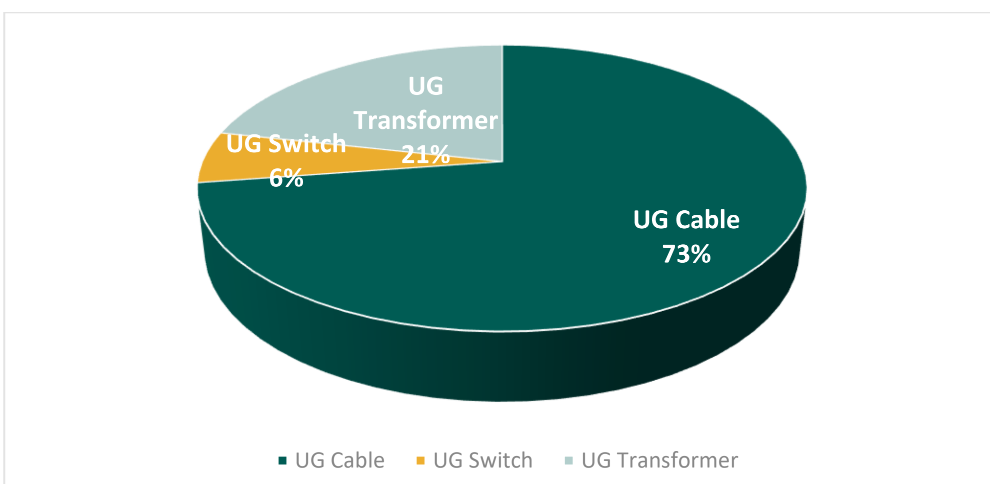


Figure 5: Underground ("UG") Equipment Failures in Underground Horseshoe System by Asset Type from 2013 to 2022

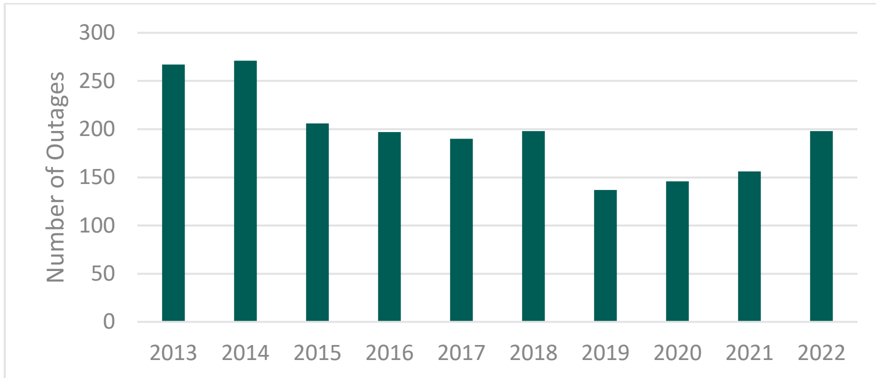


Figure 6: Ten-Year Trend of Outages due to Underground Cable Failure

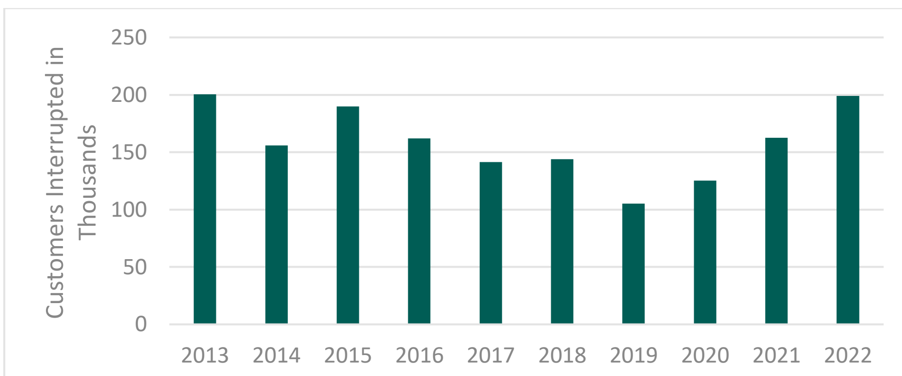


Figure 7: Ten-Year Trend of Total Customers Interrupted (CI) due to Underground Cable Failures

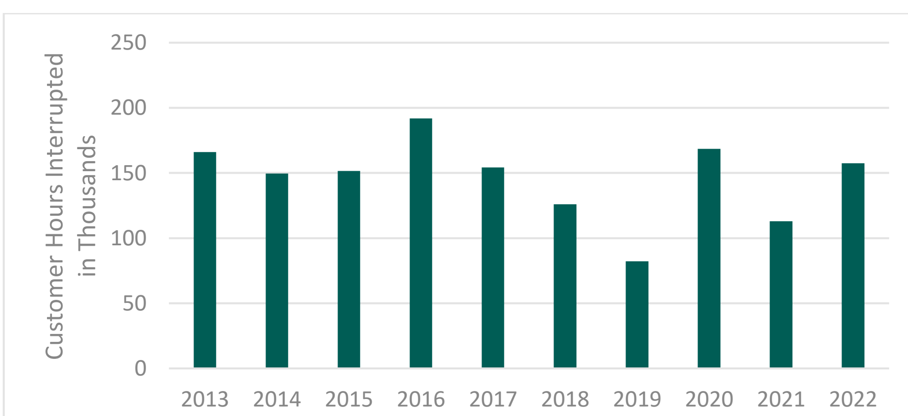


Figure 8: Ten-Year Trend of Total Customer Hours Interrupted (CHI) due to Underground Cable Failures

In addition to the type of cable, age is an important indicator of failure risk. Figures 9 depicts the age distribution of direct-buried XLPE cable (not in duct) in the Horseshoe in 2022 and 2029 (without investment). As of 2022, 73 percent of this direct-buried XLPE cable in Toronto Hydro's distribution system in the Horseshoe has reached or exceeded its useful life (i.e. 20 years). Without replacement, the length of this type of cable at or beyond useful life will reach 215 circuit-kilometres by 2029, which represents 75 percent of the direct-buried XLPE cable in Toronto Hydro's underground Horseshoe distribution system. This increased percentage of direct buried XLPE cable at or beyond useful life will heighten the risk of cable failure and further erode the reliability improvements made prior to 2020.

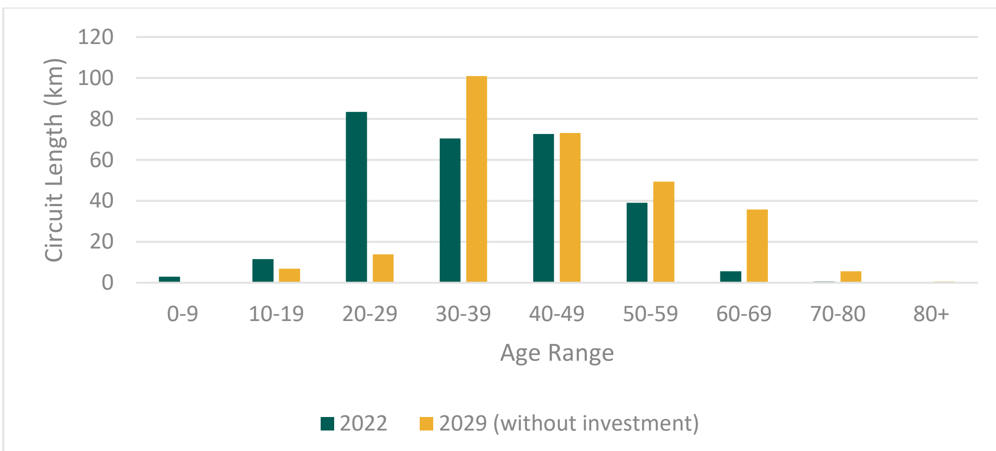


Figure 9: Age Demographics of Direct-Buried ("DB") Cable XLPE in Underground Horseshoe System as of 2022 and by 2029 (without Investment)

Figure 10 depicts the age distribution of the direct-buried cable in duct in the Horseshoe in 2022 and 2029 (without investment). As of 2022, 35 percent of this direct-buried cable in duct in Toronto Hydro's distribution system in the Horseshoe has reached or exceeded its useful life (i.e. 40 years). Without replacement, the length of this cable at or beyond useful life will reach 144 circuit-kilometres by 2029, which represents 38 percent of the direct-buried cable in duct in Toronto Hydro's underground Horseshoe distribution system. As with the direct-buried XLPE cable (not in duct), the increased percentage of direct buried XLPE cable at or beyond useful life will heighten the risk of cable failure

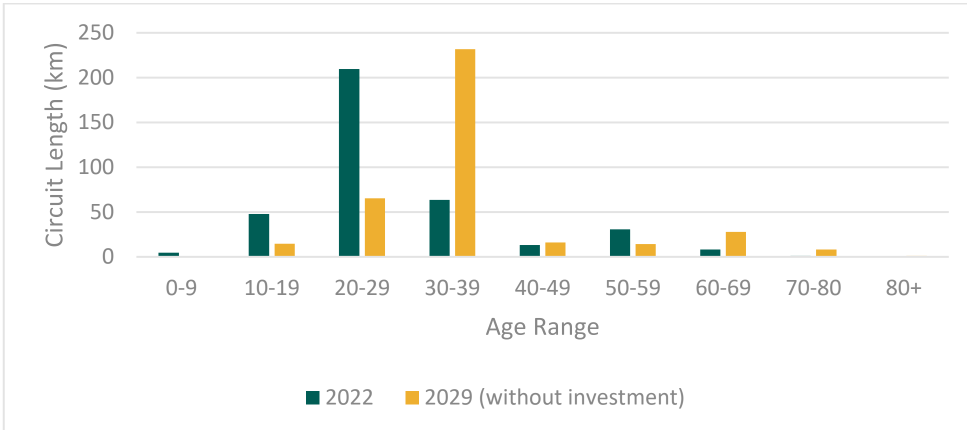


Figure 10: Age Demographics of Direct-Buried Cable in-Duct in Underground Horseshoe System as of 2022 and by 2029 (without Investment)

Although cables installed in concrete-encased ducts are more protected from environmental changes and mechanical damage, failures can still be caused by age and a variety of factors such as insulation breakdown, moisture ingress, and overload. Figure 11 shows the current age distribution of cable inside concrete-encased ducts in the Horseshoe in 2022 and in 2029 without investment. As of 2022, 9 percent of the cable inside concrete-encased ducts in the Horseshoe is at or beyond its useful life of 50 years. Without replacement, the length of cable at or beyond useful life will reach 357 circuit-kilometres by 2029, which represents 12 percent of cable installed in concrete-encased ducts. Proactive replacement of these cables is required to reduce failures and help maintain reliability on the underground system.

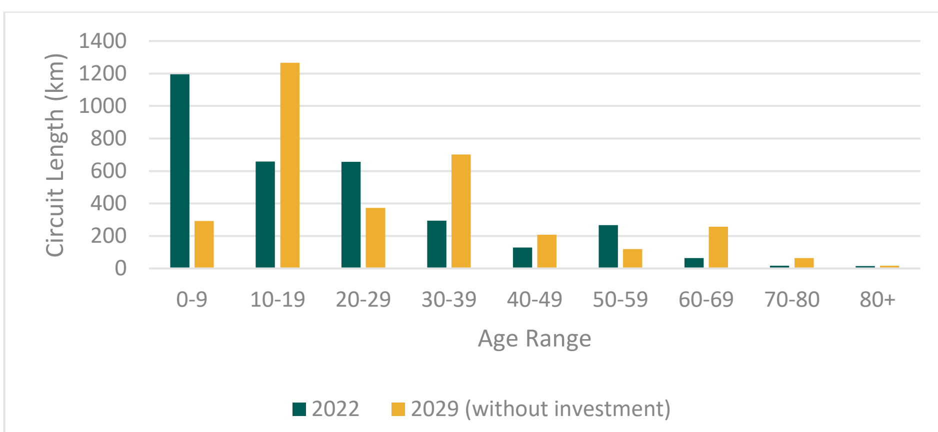


Figure 11: Age Demographic of Cable in in Concrete-Encased Ducts as of 2022 and by 2029 (without Investment)

Toronto Hydro is taking proactive measures to address the risks associated with deteriorating and legacy direct-buried cable as well as concrete-encased cable past useful life. The utility plans to replace approximately 340 circuit kilometres of underground cable, including 182 circuit kilometres of direct-buried cable (out of total of 666 circuit kilometres), through underground rebuild projects over the 2025-2029 period.

To improve reliability and public safety, Toronto Hydro plans to install new TRXLPE cable in concrete-encased ducts instead of burying cable directly into the soil or in PVC duct. This approach protects the cable from dig-ins, reducing the risk of damage and improving public safety. Additionally, installing cables in concrete-encased ducts significantly reduces the time needed to replace faulty cables, as new cables can be pulled into existing ducts. This approach will improve reliability and reduce outage times.

Toronto Hydro has also started performing cable diagnostic testing[10] on prioritized underground cables to provide a more accurate assessment of the condition of underground cables, splices, joints and terminations using a combination of very low frequency tan-delta ("VLF TD") and/or partial discharge testing on Horseshoe feeders/segments. This is executed in two phases:

- Phase 1 consists of visual inspections, Online Partial Discharge, and infrared ("IR") scanning of the end point locations to identify any immediate deficiencies.
- Phase 2 consists of monitored withstand cable testing (Time Domain Reflectometer or "TDR", as well as either online/offline Partial Discharge and/or VLF TD testing). In some cases, Phase 2 testing can only be performed after corrective actions from Phase 1 have been addressed.

In the past, factors such as age, historical failures, and number of joints were used to determine appropriate replacement strategies for these cables. However, under this program, select subdivisions in the Horseshoe area are chosen for testing to assist with making capital investment decisions using more condition-based data and to address areas with poor reliability. During 2021 and 2022, this program provided a more accurate assessment of the condition of underground cables, splices, joints, and terminations. As shown in Figure 12, this initiative has identified a number of deficiencies and generated corrective work that has helped the utility to mitigate cable failures and associated reliability risks. As this program continues to mature, the diagnostic data available on

[10] See Exhibit 4, Tab 2, Schedule 2.

cables will continue to grow and will help Toronto Hydro predict cables at risk of degradation and identify problematic locations in the system with a higher degree of accuracy. While Toronto Hydro is currently ramping up this program, it will require a significant amount of time to test the entire underground cable population and the utility will continue to lack this additional information for a large amount of cable.

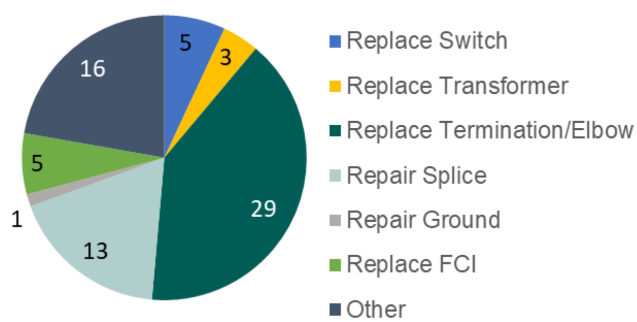


Figure 12: Type and Number of Deficiencies Identified from Cable Testing Program 2021-2022

E6.2.3.2 Replacement of Underground Transformers

Toronto Hydro plans to replace transformers that are at risk of failing and pose an environmental risk due to potential oil leaks (potentially containing PCBs). There are currently 25,753 underground transformers in Toronto Hydro's Horseshoe distribution system, with three main types: (i) submersible; (ii) padmount; and (iii) building vault. Toronto Hydro owns approximately 8,847 submersible transformers, 6,345 padmount transformers, and 10,561 vault transformers, all of which are vulnerable to deterioration from exposure to harsh environmental conditions.

Submersible transformers are located below-grade in small structures such as vaults and can be found on public road allowances or private properties. Padmounted transformers are metal-clad enclosures with lockable cabinet doors that are located on top of concrete pads, often within road allowances or on private properties. Vault transformers, on the other hand, are located above ground level in civil structures and, like padmounted transformers, supply residential areas or commercial buildings.

The harsh environmental conditions to which transformers are exposed cause them to deteriorate over time. Moisture, particularly groundwater and moisture ingress, is the most destructive element leading to the corrosion of the enclosures. Over time, precipitation and humidity can cause tank perforation, which can result in oil leakage into the environment. The oil leakage reduces transformer oil levels, causing the paper insulation to dry up. When this is combined with the heat generated due to loading, arcing can occur with the potential for a catastrophic failure of the unit. These failures pose significant risks to the public and Toronto Hydro employees as these transformers are located next to sidewalks and on private properties. A summary of the 10-year reliability of the underground transformers is shown in Figures 13 to 15. There has been an overall downward trend in the number of system outages since 2017, which is also reflected in the customer impact reliability indicators, Customers Interrupted and Customer Hours Interrupted. This improvement can be attributed to the recent focus on proactive replacement of underground transformers containing, or at risk of containing PCBs. However, in 2022 there was some worsening of transformer-related reliability and, without continuous investment in this segment, Toronto Hydro expects the reliability improvements made in recent years to be eroded and eventually reversed.

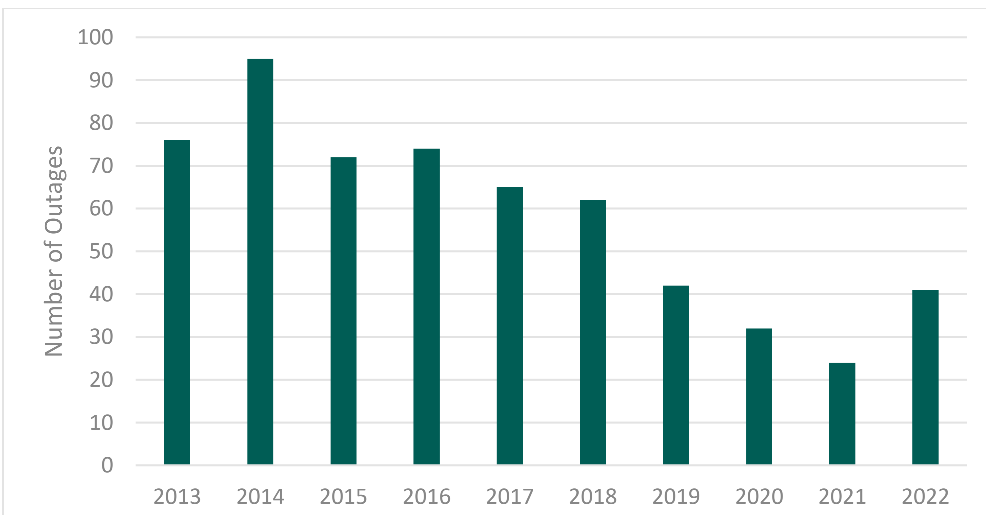


Figure 13: Ten-Year trend of Outages Due to Underground Transformer Failures

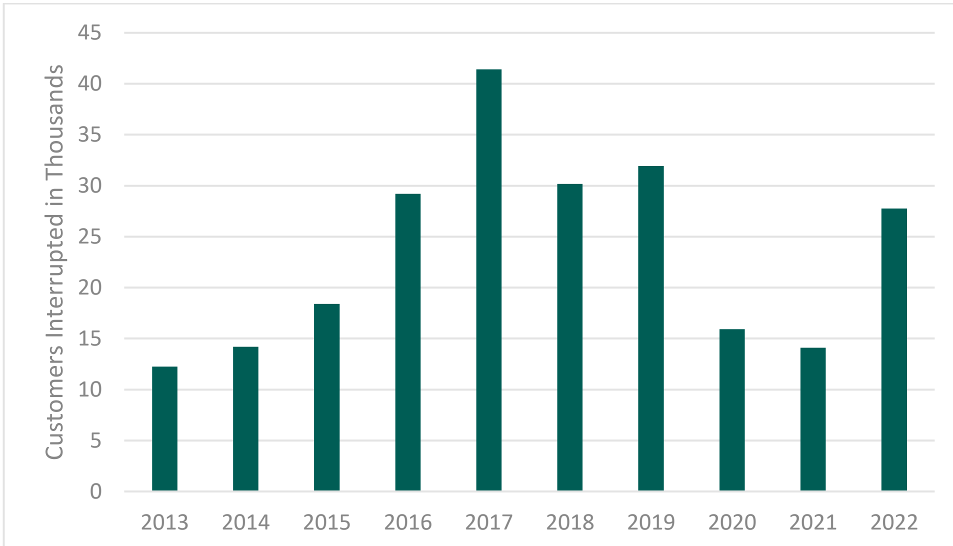


Figure 14: Ten-Year Trend of Total Customers Interrupted (CI) Due to Underground Transformer Failures

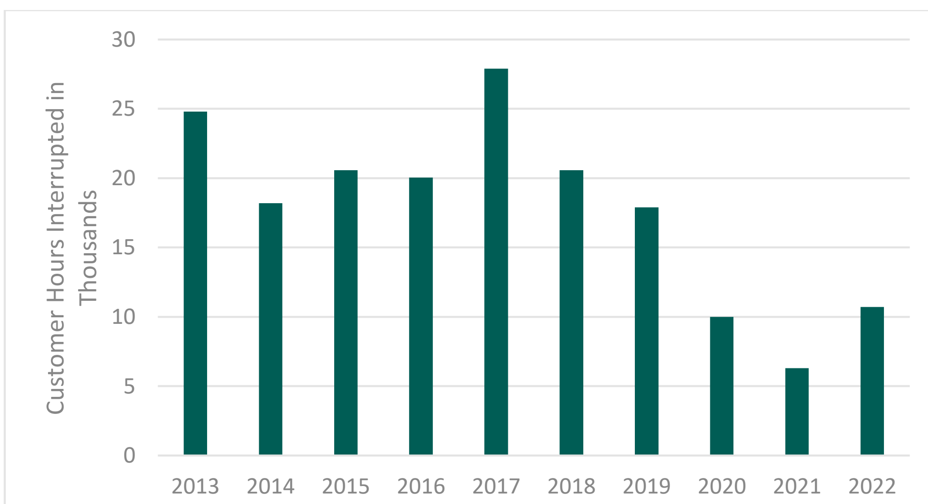


Figure 15: Ten-Year Trend of Customer Hours Interrupted (CHI) Due to Underground Transformer Failures

A number of underground transformer failures in the Horseshoe area have also resulted in oil leaks into the environment. The risk of oil leaks is particularly high for older transformers, which may contain oil with PCBs. Releasing oil, including oil containing PCBs into the environment may breach the City of Toronto's Sewer Use By-Law[11], Ontario's *Environmental Protection Act*[12] and, the federal *Canadian Environmental Protection Act*, *1999*[13] potentially resulting in penalties, or orders to perform remediation work or to otherwise address non-compliance. Toronto Hydro has been targeting underground transformers at risk of containing PCBs, which are all also past their useful life, and estimates that there will be 492 underground transformers that contain or are at-risk of containing PCBs remaining at the end of the current rate period. Toronto Hydro intends to replace all of these units by the end of 2025.

Figure 16 illustrates the number of externally-reported oil spill incidents from 2018 to 2022. The increase in reported spills from 2018-2020 is attributed to a modification of the inspection process in 2018 to improve the reporting of transformers with the potential to leak (i.e. are heavily corroded). During this time, the frequency of inspections for select submersible transformers was also increased based on the condition of the transformer from its most recent inspection. The additional inspections for the more at-risk transformers enabled Toronto Hydro to identify more oil spills, resulting in a higher number of incidents reported in accordance with Ontario's *Environmental Protection Act*[14] at Part X (Spills), and the City of Toronto's Sewer Bylaw, Chapter 681.[15]

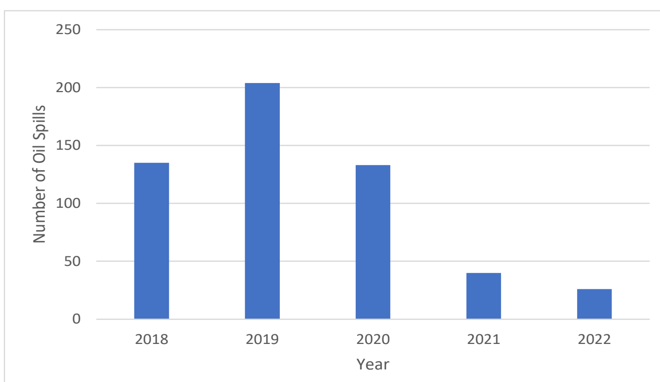


Figure 16: Number of Externally-Reported Oil Spills on Underground Transformers in Underground Horseshoe System

[11] City of Toronto, by-law No 681, Sewers, (May 15, 2023).
[12] RSO 1990, c. E.19
[13] SC 1999, c. 33
[14] RSO 1990, c. E.19
[15] City of Toronto, by-law No 681, Sewers, (May 15, 2023).

Toronto Hydro investigated 2,555 underground transformer failures that occurred between 2013 and 2022. The results of this analysis (see Figure 17 and Figure 18) show that 27 percent of the failed underground transformers failed at or beyond useful life and the number of failed units increases with transformer age. Therefore, if not proactively replaced, transformers on Toronto Hydro's distribution system, which are at or beyond their useful life of 30 years, are at an increased risk of failing.

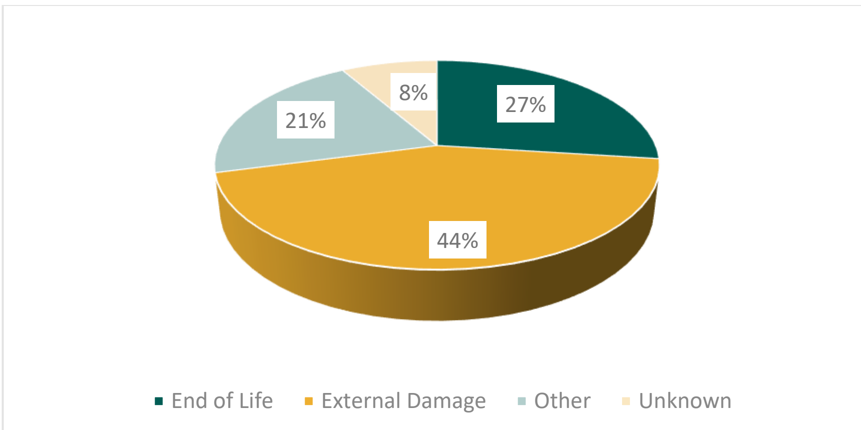


Figure 17: Root Cause Distribution for Failed Underground Transformers from 2013 to 2022[16]

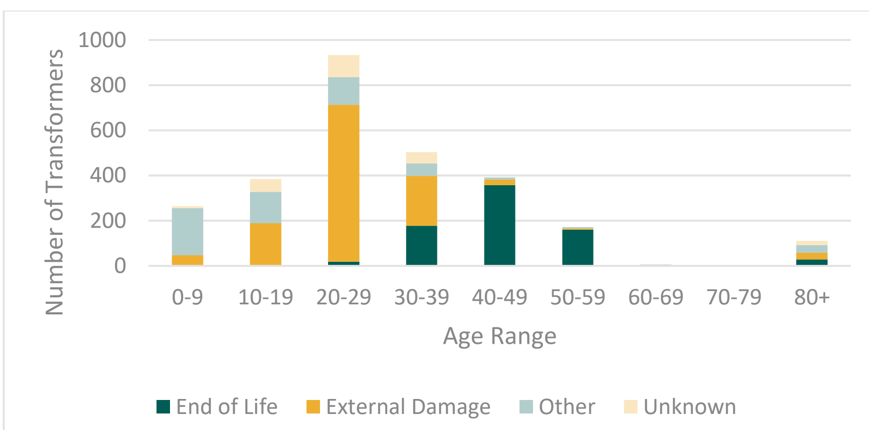


Figure 18: Age at the Time of Failure for Failed Underground Transformers from 2013 to 2022

[16] Others, represent 44 percent which include failures such as supplier quality, lighting strikes, corrosion, overvoltage, contamination etc.

Figure 19 shows the current age distribution of underground transformers in the Horseshoe area in 2022 compared to what it will be in 2029 without investment. As of 2022, 26 percent of underground transformers in the Horseshoe area (i.e. 6,727 units) were at or beyond useful life (i.e. 30 years for padmount, submersible, and vault transformers). Without any replacement, the percentage of transformers at or beyond their useful life will reach 39 percent (i.e. 10,001 units) by 2029. An increase in the number of transformers at or beyond their useful life will increase the risk of units failing, and will erode and eventually reverse the improvements in reliability made in recent years. Additionally, without sufficient replacement, Toronto Hydro will face a backlog of transformers requiring replacement beyond 2029.

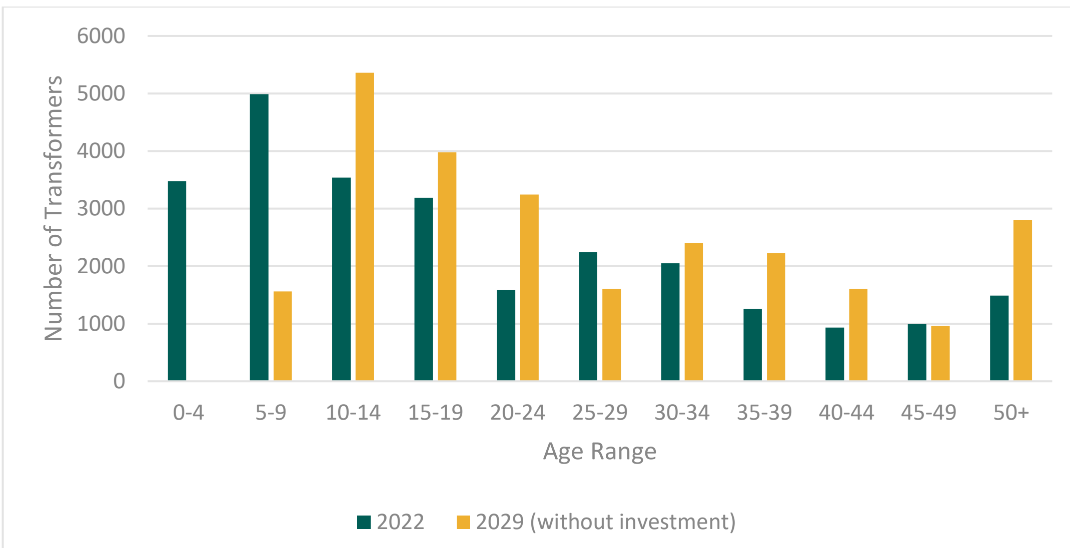


Figure 19: Age Distribution of All Transformers in Underground Horseshoe System as of 2022 and 2029 Without Investment

While age can be a good indicator of a population's current and future failure risk, asset condition assessment provides a more accurate indication of asset failure risk and the need to replace underground transformers (where PCBs are not a factor). As of the end of 2022, 639 transformers exhibit at least material deterioration (i.e. HI4 and HI5) as shown in **Error! Reference source not found.**Table 5 below. Without any capital investment, this number is expected to reach 2,400 by the end of 2029. Not investing in asset renewal will increase reliability risks on the distribution system and run the risk of negative environmental impacts from asset failure as the transformers continue to deteriorate. The asset condition profiles of the transformers as of 2022 and in 2029 (forecasted) without investment are shown in Table 5 and Figure 20.

Table 5: Asset Condition Assessment for Underground Transformers in Underground Horseshoe System in 2022 and 2029 without Investment

Condition	UG TX - Padmounted		UG TX - Submersible		UG TX - Vault		Total	Total
	2022	2029	2022	2029	2022	2029	2022	2029
HI1 – New or Good Condition	4521	3920	7666	6939	6108	4625	18295	15484
HI2 – Minor Deterioration	1009	469	548	585	3618	1533	5175	2587
HI3 – Moderate Deterioration	476	804	130	534	494	3400	1100	4738
HI4 – Material Deterioration	215	561	120	178	225	506	560	1245
HI5 – End-of-Serviceable Life	22	489	46	274	11	392	79	1155
Grand Total	**6243**	**6243**	**8510**	**8510**	**10456**	**10456**	**25209**	**25209**

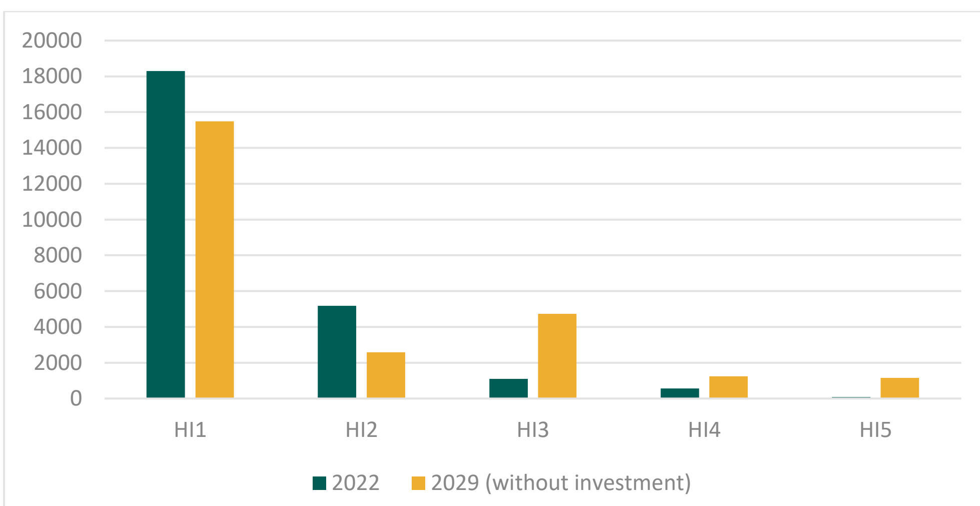


Figure 20: Asset Condition of Underground Transformers in 2022 and 2029 (without investment)

Toronto Hydro plans to replace approximately 2,500 underground transformers under this program over 2025-2029. This will be achieved through area rebuilds on 27.6 kV feeders and voltage conversions of 4.16 kV and 13.8 kV feeders, along with spot replacements of PCB transformers and transformers that are projected to be in HI4 and HI5 condition at the end of 2029 and which are not part of any rebuild project.

E6.2.3.3 Replacement of Underground Switches

Toronto Hydro also plans to replace switches as part of area rebuild projects. There are approximately 3,138 switches in service in the Horseshoe area.

Switches are critical components of Toronto Hydro's distribution system and are used for load switching, isolation, and emergency power restoration procedures. There are two types of switches used in the underground Horseshoe system: (1) padmounted switches (either air vented or sealed with SF_6 insulation) primarily installed next to boulevards for feeder switching; and (2) vault installed switches (either air vented or sealed with SF_6 insulation) used for switching and transformer isolation within a vault. The useful life of these switches is 40 years.

Switches in Toronto Hydro's underground system are exposed to harsh environmental conditions such as contamination and moisture, which can reduce their useful life. Air-vented padmounted switches, for instance, are designed to be vented naturally through louvers under the hood of the enclosure. However, this is also a route for dust and road salt to enter the switching compartments and accumulate within the switch. Although scheduled preventive maintenance, such as inspections followed by corrective CO_2 washing, can remove excessive buildup of contaminants for a limited time, repeated CO_2 washing can contribute to the degradation of the switch's insulation strength, eventually leading to failure.

As the ambient temperature changes, the trapped moisture in the enclosure condenses into water, dampening the dirt and other contaminants that are already present on the insulation surface. The surface then becomes conductive and may result in a flashover of the unit, potentially leading to failure.

A flashover in a padmounted switch can lead to a near simultaneous ignition of all combustible material within the compartment. This discharge of electrical energy can then spread to the other compartments of the switch, causing additional flashovers and combustion, ultimately resulting in the total failure of the unit. Figure 21 provides an illustration of how contaminants build up on a typical air-vented padmounted switch that could lead to a potential flashover.

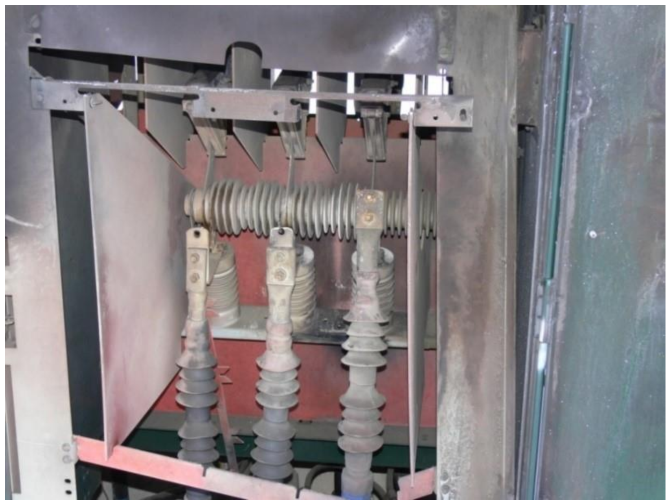
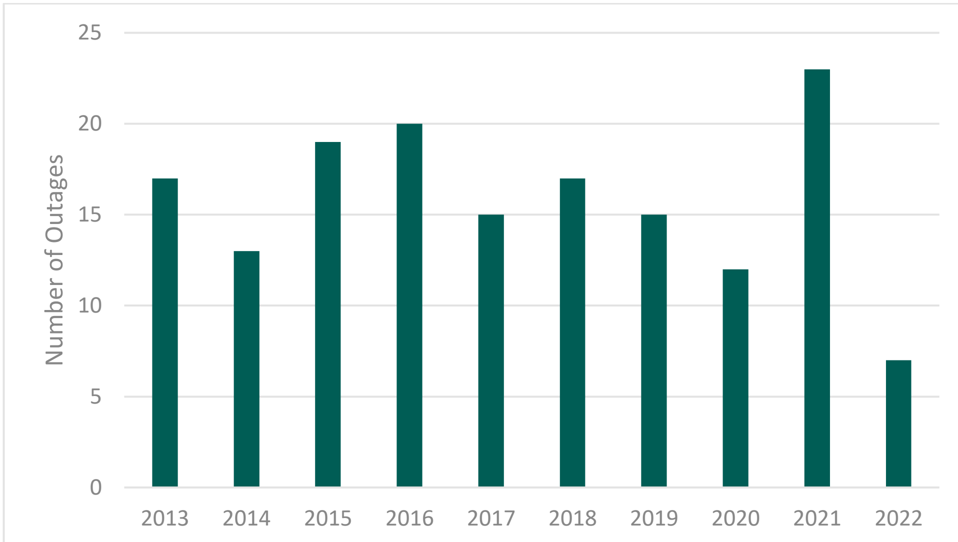


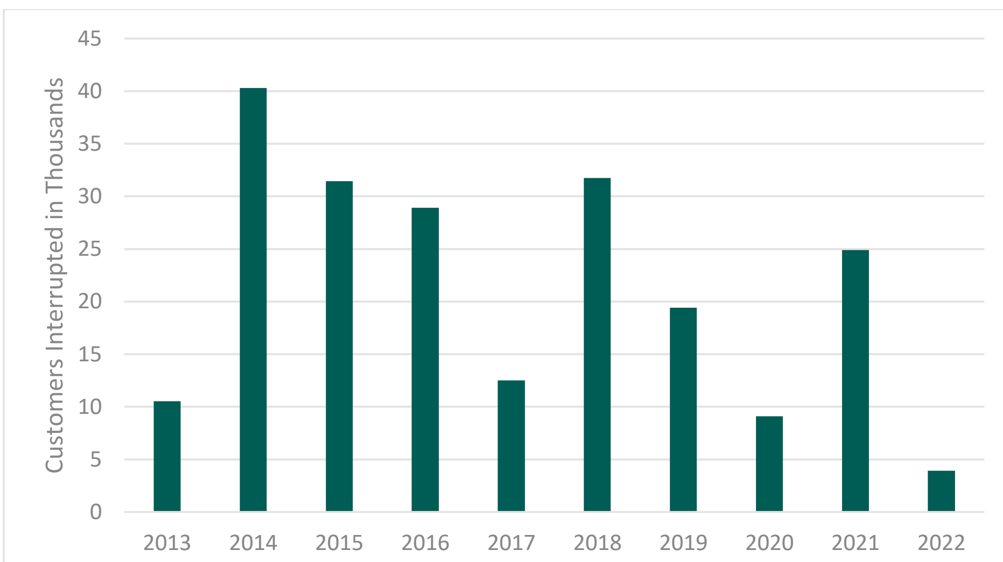
Figure 21: Padmounted switch with contaminant build-up

In Toronto Hydro's underground distribution system in the Horseshoe area, 5.8 percent of the underground outages between 2013 and 2022 were caused by switch failure. Depending upon the location of the switch, whether on the trunk or lateral portion of a feeder, a failure can lead to significant public safety risks and extensive disruption to service for an extended period of time. For example, padmounted switches are commonly connected to the trunk portion of a feeder for load distribution and switching and can lead to significant negative effect on system reliability by causing an outage, or extending a feeder outage to the bus level.

A summary of the ten-year reliability of the underground switches discussed in this Program is shown in Figures 22 to 24. Proactive replacement of switches has helped moderate the frequency of outages caused by switch failures. However, the population of switches in service is aging and if Toronto Hydro does not continue to renew them proactively, the utility expects that the current level of reliability performance will not be sustained as failure rates increase.



1 **Figure 22: Ten-Year Trend of Outages due to Underground Switch Failures**



2 **Figure 23: Ten-Year Trend of Total CI due to Underground Switch Failures**

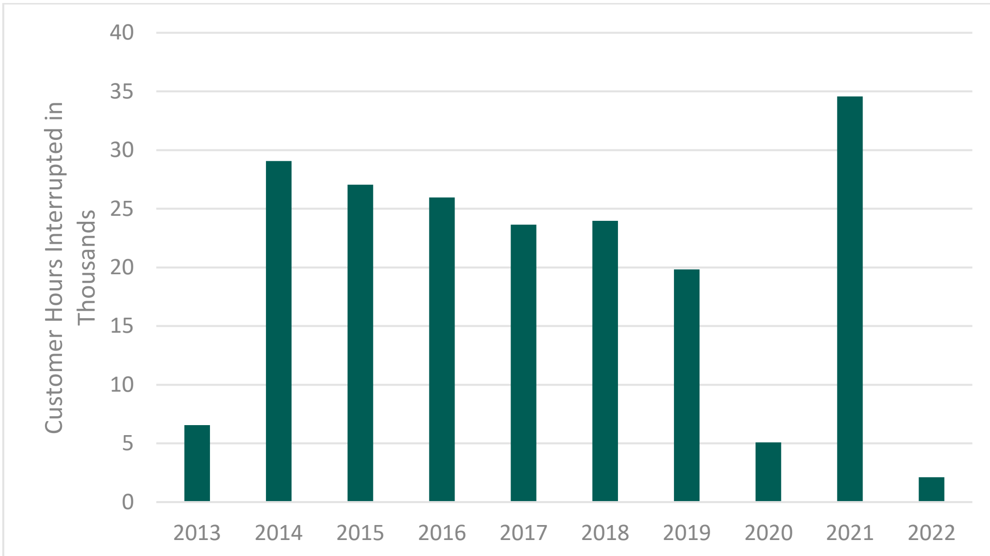


Figure 24: Ten-Year Trend of Total CHI due to Underground Switch Failure

Figure 25 and Figure 26 show the age demographics of all padmount and vault switches, which both have a useful life of 40 years. As of 2029, 86 padmount switches and 595 vault switches will be beyond useful life without investment.

Figure 25: Age Distribution of Padmount Switches in Underground Horseshoe System

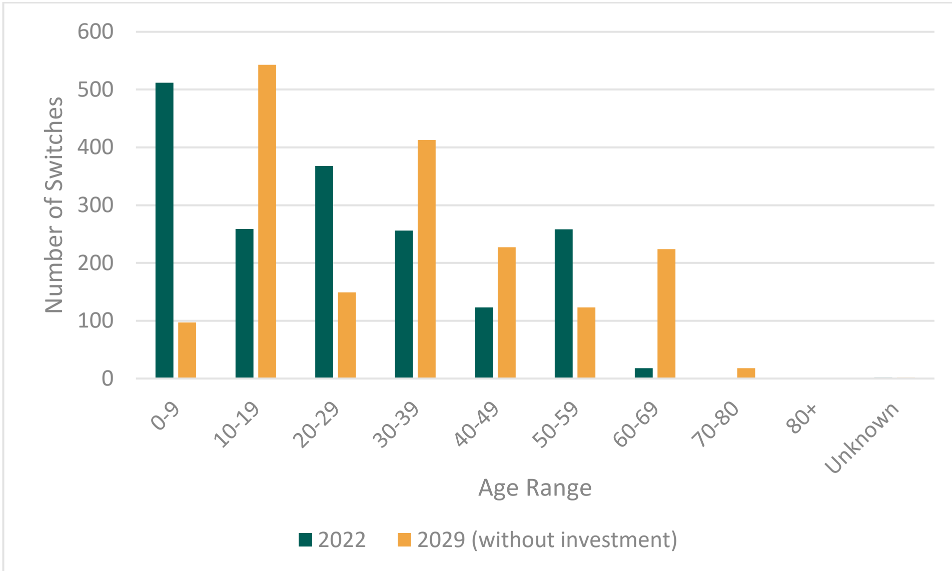


Figure 26: Age Distribution of Vault Switches in Underground Horseshoe System

Toronto Hydro's experience with padmount switches indicates that the majority of these units fail before their expected useful life. Toronto Hydro investigated 359 padmount switch failures that occurred between 2013 and 2022. The results of this analysis (see Figure 27) show that majority of padmount switches failed before the end useful life (40 years) and typical failures are attributed to external factors such as weather, contamination, and corrosion.

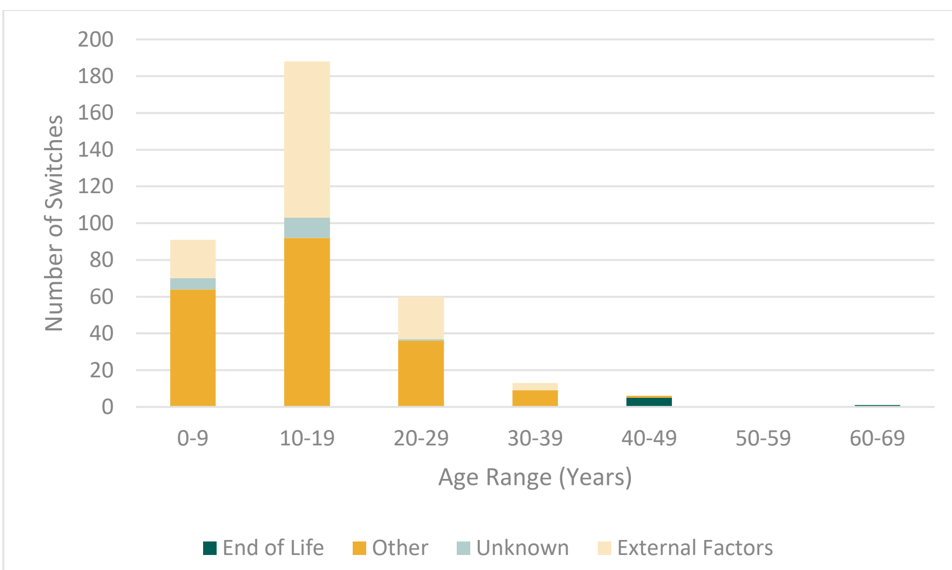


Figure 27: Age and Cause of Failure for Failed Padmount Switches from 2013 to 2022

Condition data for Air and SF6 type underground padmounted switches are shown in Table 6 and Figure 28. There are 70 padmounted switches in HI4 and HI5 as of the end of 2022 and, without investment, that number will almost double to 134 by 2029. An increased number of padmount switches with at least material deterioration will elevate the risks of units failing and therefore, without investment the recent improvements in switch-related reliability will likely erode and eventually reverse.

Table 6: Asset Conditioning for Underground Padmounted Switches – Air and SF_6 Type

Condition	UG Switch Padmounted Air		UG Switch Padmounted SF6		Total 2022	Total 2029
	2022	2029	2022	2029		
HI1 – New or Good Condition	355	346	635	635	**990**	**981**
HI2 – Minor Deterioration	4	11	0	0	**4**	**11**
HI3 – Moderate Deterioration	64	2	0	0	**64**	**2**
HI4 – Material Deterioration	24	13	1	0	**25**	**13**
HI5 – End-of-Serviceable Life	29	104	16	17	**45**	**121**
Grand Total	**476**	**476**	**652**	**652**	**1128**	**1128**

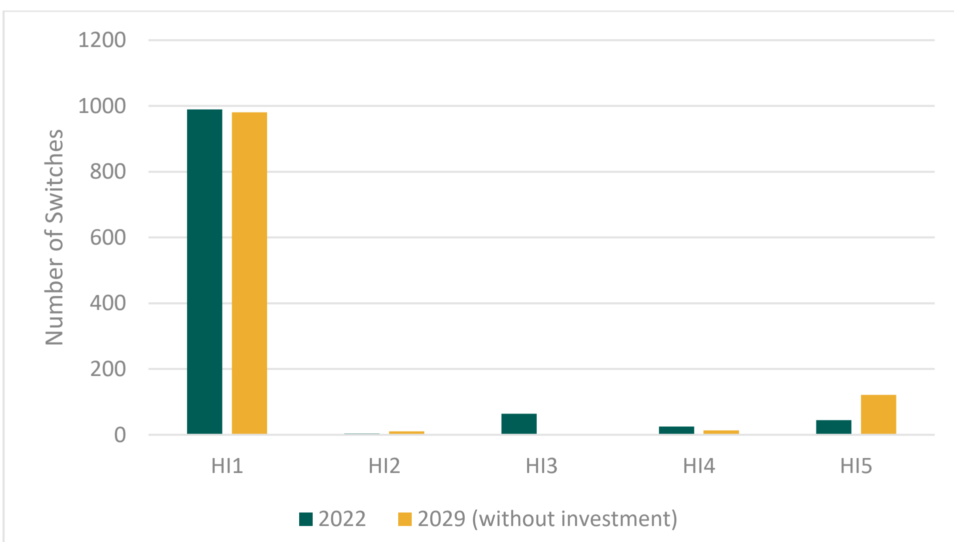


Figure 28: Asset Condition of Underground Switches in 2022 and 2029 (without investment)

To address the risks associated with air vented padmounted switches, Toronto Hydro plans to replace them with the new generation of SF_6-insulated switches. These new switches feature a stainless-steel enclosure to prevent premature rusting and degradation of the cabinet. The unit includes welded viewing windows that mitigate SF_6 gas leakage into the environment. Programmable relays are also used for downstream circuit protection, eliminating the need for on-site switch re-fusing after a fault on the branch circuit. The units have internal grounding provisions making grounding easier and safer for crews in comparison to the external grounding elbows on the existing switches.

The new SF_6 switches also enable SCADA capability for remote sensing, leading to increased system efficiency and improving restoration time in the event of a power failure, while avoiding costs associated with crews physically operating the switch on site. Another advantage of padmounted SF_6 insulated switches is that they have the same circuit configuration and footprint as the existing air insulated padmounted units, thereby avoiding unnecessary cable and civil construction work. Additionally, all external components of the SF_6 insulated switches are sealed and do not require routine CO_2 washing to remove accumulated contaminants.

To mitigate environmental risks related to SF6 insulated gear, Solid Dielectric (“SD”) switchgear is being trialed as an alternative. The SD gear shall have the same SCADA capability as the SF6 gear and shall maintain the same circuit configuration and foundation design to avoid unnecessary cable and civil construction work.

Toronto Hydro plans to replace approximately 116 padmount switches over 2025-2029 as part of area rebuild projects under this Program. The remaining padmounted switches and vault switches that have at-least material deterioration and are not part of the rebuild scope will be replaced through the Reactive and Corrective Capital program[17] upon failure as they do not present environmental risks.

E6.2.4 Expenditure Plan

Table 7: Historical & Forecast Program Cost ($ Millions)

	Actuals			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Underground System Renewal Horseshoe	73.5	50.9	64.4	92.3	78.7	92.6	82.3	93.8	101.1	105.9

[17] Exhibit 2B, Section E6.7.

E6.2.4.1 2020-2024 Variance Analysis

Over the 2020-2024 period, Toronto Hydro forecasts total spending of $351.8 million in the Underground System Renewal program, which is approximately $108 million lower than planned in the 2020-2024 Distribution System Plan. Toronto Hydro reduced the Program budget to support meeting the utility's capital funding limits while managing overall risk on the distribution system. In particular, this involved shifting away from direct-buried cable replacement, while still prioritizing underground transformers at risk of containing PCBs.

Over the 2020-2022 period, Toronto Hydro spent $188.8 million and installed 325 kilometres of underground cable in duct, 1,013 transformers, and 127 underground switches, as shown in Table below. Toronto Hydro plans to invest another $163 million in 2023-2024.

Table 8: 2020-2024 Volumes (Actual/Bridge) – Underground Circuit Renewal Horseshoe Program (Primary Electrical Assets)

Asset Class		Actuals			Bridge		Total
		2020	2021	2022	2023	2024	
Total Cable	*km*	114	83	128	175	63	563
Direct-Buried Cable[18]	*km*	29	32	18	13	13	105
Transformers	*Units*	307	425	281	406	361	1677
Switches	*Units*	55	20	52	18	17	162

As noted above, the utility has been prioritizing replacement of underground transformers with PCBs (i.e. through spot replacements) in order to eliminate them by 2025. However, challenges acquiring transformers has reduced Toronto Hydro's ability to ramp up the pace of replacements as intended, resulting in a notable decrease in units completed in 2022. The utility has been working diligently to mitigate the impacts of supply chain issues (see Exhibit 4, Tab 2, Schedule 15) and while the utility expects to increase the pacing in 2023, it is still on track to replace fewer transformers than originally planned. In addition, with the reduced budget and focus on PCB transformers, Toronto Hydro invested less in area rebuilds, resulting in less direct-buried cable and fewer switches replaced than proposed in the 2020-2024 DSP.

[18] Note that the Direct-Buried Cable amounts in this table are a subset of the Total Cable amounts in the row above.

More broadly, unit volume and cost variances can be attributed in part to changes in the scope of work as projects moved from high-level estimates to detailed designs. These changes are anticipated for complex construction projects and typically result from a more detailed review of the scope of work and execution needs during the design phase. For example, designers may identify additional or fewer assets that should be included in a project, interference with other utilities and a resultant need to adjust the scope, additional restoration costs, etc., that influence the final cost of a project.

E6.2.4.2 2025-2029 Forecasts

Toronto Hydro plans to spend $475.7 million in this Program over the 2025-2029 period. The 2025-2029 forecast expenditures are based on Toronto Hydro's historical unit costs trends and experience with executing this type of work over recent years. The estimated volumes for major underground asset replacements during the 2025-2029 period are shown in Table 9.

Table 9: 2025-2029 Estimated Volumes (Forecast) – Underground System Renewal (Primary Electrical Assets)

Asset Class		Forecast					
		2025	2026	2027	2028	2029	Total
Total Cable	*km*	30	72	84	79	75	**340**
Direct-Buried Cable	*km*	25	38	45	35	39	**182**
Transformers	*Units*	870	352	346	429	481	**2,478**
Switches	*Units*	12	22	28	26	28	**116**

The forecasted volumes are estimates based on a preliminary selection of areas targeted for complete rebuilds on 27.6 kV feeders, rebuilds with voltage conversion, and spot replacements.

- **Area Rebuilds on 27.6 kV Feeders:** Area rebuild projects involve the prioritization and replacement of major assets such as cable, switches, and transformers, in areas where historical failures and deteriorated asset conditions pose particularly high risk to reliability. Area rebuilds ensures Toronto Hydro is able to coordinate work in an area and efficiently mobilize crews to minimize customer outages. By replacing entire sections on the distribution system on the feeders selected for rebuild, Toronto Hydro can ensure that customers only undergo one planned outage as opposed to numerous outages resulting from reactive work or spot replacements.

- **Area Rebuilds with Voltage Conversion:** Where a feeder identified for renewal through area rebuilds is operating on 4.16 kV and 13.8 kV voltages, it will be converted to 27.6 kV. Similar to area rebuilds, Toronto Hydro plans to select 4.16 kV and 13.8 kV for conversion based on historical performance, the number of assets that are in deteriorated condition or at or beyond useful life, and potential impact on customers supplied by the feeder for area conversion.
- **Spot replacement:** Transformers that need replacement but are not part of area rebuild projects will be addressed on a case by case basis through spot replacement projects. These projects will focus on replacing assets that are identified as having at-least material deterioration or pose environmental risks due to oil leaks. Spot replacement projects aim to reduce the likelihood of failures and mitigate the risk of negative environment impacts from oil leaks.

Once Toronto Hydro has removed all underground transformers containing PCBs, it will shift back towards an approach that includes more rebuilds focused on direct-buried cable and limiting spot replacements to only the worst condition transformers not addressed elsewhere.

Whenever possible, work under this Program is combined or coordinated with projects from other programs (such as overhead renewal and rear lot conversion) in the same area. Underground renewal projects are broken into civil and electrical phases, and those with significant amounts of civil work are broken down further into sub-phases for better manageability and coordination of resources.

Equipment in the same area and fed from the same Toronto Hydro feeders is coordinated in terms of replacement schedule and sequencing. This approach reduces disruption of supply and requires less mobilization of resources to the same area. Reduced disruption to feeders translates into fewer outages for customers, and improves project efficiencies. In addition, any voltage conversion underground work is coordinated with stations maintenance and capital work. This allows Toronto Hydro to eventually decommission Municipal Stations prior to any major maintenance or renewal investments.

Once projects are scoped at a high level, they undergo a field inspection in order to validate the scope of work, identify third party conflicts, and refine estimates before design finalization. Through this process, projects identified for renewal may be subject to change, and poorly performing feeders that demonstrate higher risks may take priority.

E6.2.5 Options Analysis

Toronto Hydro considered the following options for the Underground System Renewal program. Under each of these options Toronto Hydro would seek to replace all remaining underground transformers containing, or at risk of containing, PCBs by the end of 2025 and will only replace switches proactively through area rebuilds (i.e. no spot replacement of underground switches).

E6.2.5.1 Option 1: Limited Area Rebuilds (15 feeders), Voltage Conversion (14 feeders) and Spot Replacements of PCB Transformers Only

Under this option, Toronto Hydro would rebuild 29 feeders, including the conversion of 14 feeders operating on 4.16 kV and 13.8 kV voltages to 27.6 kV. With this approach, Toronto Hydro would replace 140 km of cable, of which 98 km is direct-buried (15 percent of total direct-buried cable remaining as of 2022) and 42 km is cable in concrete-encased ducts beyond useful life. At this pace, it would take 30-35 years to eliminate all the direct-buried cable from the system, during which time customers would be exposed to increasing reliability risk as the cables continue to age. There would also be 237 km of cable in concrete-ducts beyond useful life remaining in the system by 2029 compared to 121 km under Option 2.

This option will lead to minimal improvement in cable failures wherein only limited sections of direct-buried cable and cables beyond useful life will be replaced. Given the significant contribution of cables to underground outages and the 542 km of direct-buried cable remaining and 7.6 percent of cables in concrete-encased ducts beyond useful life by 2029 under this option, the utility expects there would be higher costs and disruptions to the public and customers for reactive work.

This option also includes spot replacements of the remaining transformers containing PCBs. Although planned rebuilds will address some transformers past useful life and/or with at least material deterioration, there will continue to be a significant number remaining on the system, increasing the risks of failures and reversing recent improvements in transformer-related reliability and oil spills.

While this option’s pace of investment would reduce program costs significantly, the resulting increases to reliability risk and expected impact on customers is not aligned with customer preferences, which includes reliability as a top priority.

E6.2.5.2 Option 2 (Selected Option): Area rebuilds (29 feeders), Voltage Conversion (29 feeders), Spot Replacement of Both PCB and Materially Deteriorated Transformers

Under this option, Toronto Hydro plans to rebuild 58 feeders, including 29 feeders converted to 27.6 kV. With this approach, Toronto Hydro will replace 340 km of total underground cable in the Horseshoe, out of which 182 km will be direct-buried cable (21 percent of total direct buried cable as of 2022) and 158 km will be cable in concrete-encase ducts beyond useful life. At this pace, it will take 20-25 years to eliminate all of the direct-buried cable from the system and there will be an estimated 121 km of cable inside concrete-encased ducts that is beyond useful life by 2029.

Toronto Hydro projects that under this option there will be 458 km of direct-buried cable remaining on the system and 3.8 percent of cables in concrete encased ducts will beyond useful life by 2029. Although, this is still a significant amount of direct-buried cable and end-of-life cable left in the system, it is an improvement over Option 1 and would mitigate the expected reliability impacts of that option. Toronto Hydro finds this pace of cable renewal to be the most reasonable balance between outcomes such as reliability and costs.

Under this option, Toronto Hydro plans to replace approximately 2,500 underground transformers through area rebuilds and through spot replacements of transformers that are projected to be in HI4 and HI5 condition at the end of 2029 and are not part of any rebuild project. This will also include the remaining 492 underground transformers in the Horseshoe area that contain (or are at-risk of containing) PCBs. This option will mitigate the potential accumulation of a large backlog of transformers that are at a high risk of failure and in need of replacement beyond 2029 as well as mitigate the environmental risks associated with leaking oil.

E6.2.5.3 Option 3: Area rebuilds (30 feeders), Voltage Conversion (38 feeders), more DB cable replacement, spot replacement of remaining transformers containing PCB along with assets with at-least material deterioration at the end of 2029

Under this option, Toronto Hydro would fully rebuild a total of 68 feeders, 38 of which would be converted to 27.6 kV. With this approach, Toronto Hydro would replace 375 km of total cable, out of which 215 km is direct-buried cable (32 percent of total direct-buried cable remaining as of 2022) and 160 km is cable in concrete-encased ducts beyond useful life. At this pace Toronto Hydro would eliminate all direct-buried cable within 15-20 years and would reduce the cable inside concrete ducts beyond useful life to 119 km by 2029.

Under this option, the amount of direct-buried cable remaining in the system would be reduced to 425 km by 2029, improving expected reliability relative to the other options.

This option also includes the spot replacement of any remaining underground transformers containing PCBs along with any additional transformers remaining in the system that are projected to be HI4 or HI5 by 2029 without investment and that are not part of any rebuild project. The replacement of these remaining transformers not addressed through the rebuilds would help to reduce the risk of failures as well as to mitigate the environmental risks associated with leaking oil.

This option would ensure that Toronto Hydro would have substantially less backlog of deteriorated and end of life assets by 2029 and less areas in the underground system that are supplied by 4.16 kV and 13.8 kV. While this option is the best one for mitigating reliability and environmental risk, the cost is much higher and it does not represent a balanced trade-off between risk mitigation and price.

E6.2.6 Execution Risks & Mitigation

Project execution begins with the civil phase of the underground renewal project. Electrical construction commences upon completion of the civil work. The risks associated with the Underground System Renewal program include, but are not limited to:

- Unforeseen updates and changes to existing road moratoriums imposed by the City of Toronto in areas where Toronto Hydro intends to perform underground renewal work. To mitigate this risk, Toronto Hydro will coordinate closely with the City of Toronto and its representatives, i.e. Ward Councillor, Business Improvement Area delegates.

- Unforeseen weather conditions that may affect Toronto Hydro's ability to carry out planned outages. Extreme weather conditions such as heat restrictions during summer or harsh winter storms, can also impact construction schedules. Toronto Hydro addresses this risk by closely monitoring weather forecasts and making necessary adjustments to the construction schedule to minimize the impact of adverse weather conditions.

- Third-party conflicts may require Toronto Hydro to modify its trench route due to underground space limitations, resulting in higher than estimated project costs. Toronto Hydro mitigates this risk by engaging with third parties in the design phase to ensure close coordination and alignment. This involves participation in the Toronto Public Utility Coordinating Committee meetings to identify and avoid third party conflicts.

- Some projects require work within customer owned civil structures or consent on easements from customers to install distribution assets on private property. In the case of customer-owned civil structure, the customer may have to perform civil rebuild work prior to Toronto Hydro commencing its activities, causing project delays. Toronto Hydro mitigates this risk by inspecting customer owned assets during the design phase and communicating to the customer by issuing Customer Advice Form ("CAF") for any deficiency identified. This ensures that customers are given advanced notice and have an opportunity to raise their concerns and address the civil work in a timely manner. For permits and easements, Toronto Hydro will reach out and engage customers early in the design phase of the project to account for the possibility of delays. This gives customers the opportunity to meet with the utility to discuss the details of the project and any concerns. This proactive customer engagement approach has been successful in minimizing construction delays.

- All underground projects are designed and constructed in accordance with approved Toronto Hydro's standards and specifications. However, in certain cases, deviations or special considerations are needed during design. Toronto Hydro will follow its established process for all deviation requests so that they can be assessed and approved by the standards department in a timely manner during the design phase. This process helps to prevent delay or costly rework due to operational issues during the execution of the projects.

- Longer lead time for material, especially underground transformers, can seriously impact project execution, resulting in delays or deferrals into future years. This is mitigated through proactive internal engagement and coordination and Toronto Hydro's procurement strategy. For more details on this procurement strategy and what Toronto Hydro has been doing to address this issue please see Exhibit 4, Tab 2, Schedule 15 (Supply Chain).

E6.3 Underground System Renewal – Downtown

E6.3.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 80.6	**2025-2029 Cost ($M):** 165.1
Segments: Cable Chamber Renewal, Underground Cable Renewal, Underground Residential Distribution Renewal, Underground Switchgear Renewal	
Trigger Driver: Failure Risk	
Outcomes: Operational Effectiveness - Reliability, Environment, Operational Effectiveness - Safety	

The Underground System Renewal – Downtown program (the "Program") addresses aging, deteriorating and poor performing underground distribution assets in the downtown core area of pre-amalgamation City of Toronto.[1] This Program continues rebuild and replacement activities for deteriorating and functionally obsolete underground assets in the City's core. Starting in 2020, most of these assets have been managed through a combination of preventative maintenance, targeted refurbishment, planned system renewal and in the event of asset failure, reactive and corrective capital and maintenance programs.[2][3][4] The average condition of these assets (in addition to other pressures discussed below) necessitates a targeted renewal strategy; targeting worst performing and highest risk areas.

The Program is designed to maintain reliability, mitigate asset failure and public safety risks within the downtown core by: (1) replacing obsolete underground lead covered cables with standard tree retardant cross-linked polyethylene ("TRXLPE") cables, (2) reconstructing cable chambers (or components; e.g. roofs, duct banks) at risk of failure due to poor structural conditions, (3) proactively replacing end-of-life and obsolete underground residential distribution ("URD") assets, and (4) proactively replacing end-of-life and obsolete underground switchgear.

The Program is grouped into the four segments summarized below:

[1] This Program does not address network units or network vaults. Network equipment is addressed within the Network System Renewal program (Exhibit 2B, Section E6.4)
[2] See Exhibit 4, Tab 2, Schedules 1, 2, and 3 Preventative and Predictive Maintenance programs
[3] See Exhibit 2B, Section E6.7
[4] See Exhibit 4, Tab 2, Schedule 4 Corrective Maintenance

- **Underground Cable Renewal:** The Underground Cable Renewal segment is a continuation of the activities identified in Toronto Hydro's 2020-2024 Distribution System Plan ("DSP"). This segment replaces obsolete underground lead covered cables with standard tree retardant cross-linked polyethylene cables. Based on the age and condition of Toronto Hydro's population of lead cables, the utility anticipates a decline in reliability performance and an increase in operational and safety risks. Toronto Hydro recognizes the customer value stemming from the removal of these high risk, lead based cables, and plans to invest $61 million over the 2025-2029 period to replace approximately 3.5 percent of 985 km paper-insulated lead-covered ("PILC") cable and 5.3 percent of 176 km asbestos-insulated lead-covered ("AILC") cable. Replacement of legacy PILC and AILC cables will allow Toronto Hydro to maintain reliability performance by proactive replacement of high risk cables. This will also decrease the presence of designated substances (i.e. lead and asbestos) on the grid. These cables are a critical part of the distribution infrastructure serving large customers (e.g. major financial institutions) and other reliability-sensitive customers (e.g. multi-residential high-rises) in the downtown core. Toronto Hydro uses risk-based prioritization, which considers historical failures, age, feeder uniformity based on cable type, and the magnitude and criticality of the load served by each feeder, to direct expenditures to the projects with the greatest customer value. In addition to removing lead-based cable, Toronto Hydro plans to install approximately 5 km of fiber optic cable to enable on line cable monitoring. On line cable monitoring will provide real-time thermal profile of cables and loading data which could be used for cable risk assessment and replacement prioritization in the future.

- **Cable Chamber Renewal:** This segment involves the reconstruction of cable chambers or cable chamber components (e.g. roofs, duct banks) that are at risk of failure due to their poor structural condition. Prior to 2020, Toronto Hydro managed the reconstruction of cable chambers reactively. However, due to the growing number of failing chambers and the complexity of chamber reconstruction work, Toronto Hydro introduced a planned renewal segment in 2020. The vast majority of chambers in Health Index ("HI") band 4 (material deterioration) and HI5 (end of serviceable life) condition are located in the downtown core, where there is heavy vehicular and foot traffic and a high density of circuits running through each chamber.[5] These chambers can hold up to 29 circuits, supplying up to 3,500 customers

[5] For many of its major assets, Toronto Hydro performs asset condition assessment ("ACA"), in which the condition of each asset is assigned a health index ("HI") band from HI1 to HI5, where HI5 indicates the worst condition. For these

per chamber. Typically, these are chambers that supply large condominiums with many suite-metered residential customers. Chambers can also supply one or several large industrial or commercial customers. As of 2022, 592 cable chambers were in HI4 or HI5 condition and this is projected to grow to 1,113 by 2029 without investment. To mitigate this growing backlog and associated safety and reliability risk, Toronto Hydro plans to address 199 cable chambers or cable chamber components. Toronto Hydro also plans to replace 2,800 cable chamber lids to address the public safety risks in high traffic areas. The total forecast cost for this segment is $96.5 million.

- **Underground Residential Distribution ("URD") Renewal:** This segment is focused on the URD system – a unique looped distribution design serving primarily low-rise residential customers in limited areas of the pre-amalgamation City of Toronto. Prior to 2020, Toronto Hydro managed the replacement of URD assets on a reactive basis. However, due to the growing number of failing URD vault roofs, severe corrosion, deteriorating and obsolete equipment, Toronto Hydro introduced a planned renewal segment in 2020. The utility plans to invest approximately $4.8 million over 2025-2029 to proactively replace end-of-life and obsolete URD assets that contribute to the deterioration of URD system reliability, namely switching and non-switching vaults, switches, and transformers. In addition, Toronto Hydro plans to install new Faulted Circuit Indicators ("FCIs") on URD feeders that experience the most outages. Toronto Hydro's objective for 2025-2029 is to invest the amount needed to maintain average reliability performance for the customers served by this system. The utility aims to achieve this by targeting the worst condition, obsolete, and most critical URD assets.

- **Underground Switchgear Renewal:** This segment replaces underground switchgear in customer owned vaults that feed apartment buildings, educational facilities and community centres. To date, Toronto Hydro has managed the replacement of this type of assets on a reactive basis. However, due to the growing number of deficiencies of underground switchgear where repairs are not an option and require replacement due to obsolescence, Toronto Hydro is introducing a planned renewal segment starting in 2025. The utility plans to invest approximately $2.9 million over 2025-2029 to proactively replace end-of-life and obsolete underground switchgear. Toronto Hydro's objective for 2025-2029 is to invest the amount needed to maintain average reliability performance for the customers served by

same assets, the utility can then also project future condition (i.e. HI band) assuming no intervention. See Exhibit 2B, Section D, Appendix A for more details on Toronto Hydro's ACA methodology these assets. The utility aims to achieve this by targeting the worst condition and most critical assets.

The Underground System Renewal – Downtown program for the 2025-2029 rate period is also aligned with the objectives of addressing environmental and safety risks associated with distribution assets containing PCB, lead, or asbestos. The total proposed investment for the Program in 2025-2029 is $165.1 million.

E6.3.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Operational Effectiveness – Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) and reduces the risk of lengthy outages on feeders serving thousands of downtown customers, including large, critical customers in the core while improving long-term system health by: o Replacing an estimated 35 kilometres of PILC cable that is subject to a high risk of failure. o Rebuilding/repairing/abandoning 199 cable chambers known to be in HI4 and HI5 condition. o Reducing the average number of transition joints on downtown feeders. o Replacing FCIs at end of service life on select URD feeders, enabling crews to quickly find faults and reduce restoration time. o Replacing 20 end of life and obsolete underground switchgear
Environment	• Contributes to Toronto Hydro's environmental objectives and reducing the risk of toxic exposure to the environment by: o Eliminating PILC cable containing oil and potentially PCBs; o Eliminating AILC cable containing asbestos; o Eliminating PILC and AILC cable containing lead; and o Replacing URD transformers containing oil. • Contributes to the utility's commitment to reduce greenhouse gas emissions by replacing URD switches containing SF6 gas.
Operational Effectiveness - Safety	• Contributes to the utility's public and employee safety objectives and performance by: o Replacing 2,800 chamber lids to reduce the risk of injury or property damage from cable chambers lid ejections;

	○ Eliminating safety hazards such as poor structural integrity and cable congestion; ○ Reducing the safety hazards related to the structural failure of cable chambers and URD vaults roofs in high-traffic areas by replacing or abandoning HI4/HI5 condition chambers, and chambers / vaults roof rebuild; and ○ Reducing the potential exposure to lead and asbestos (which are classified as Designated Substances under the Occupational Health and Safety Act6 (Ontario Regulation 490/09 Sections 5 and 10). ○ Safely handle and dispose of asbestos (and lead) as prescribed in the Ontario Occupational Health and Safety Act 7(Reg. 8338) and the Canadian Environmental Protection Act. ○ Replacing an estimated 4,000 cable splices thus reducing the risk of cable chamber lid ejections ○ Reducing the safety hazards related to arc flash incidents due to maloperation of underground switches by replacing HI4/HI5 underground switchgear.

E6.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Functional Obsolescence, Safety, Environmental Risk

The Underground System Renewal – Downtown program is driven by the failure risk of key assets that negatively impact reliability and safe operation within the downtown core. Historically, these assets had shown high reliability but have now become obsolete or pose a risk to the public and the environment. Many of these assets are vital to supply critical customers in the downtown district. These are of particular concern for both residential and large commercial customers who identify reliability as one of their top needs and the majority support investments that reduces outages as demonstrated through the customer engagement surveys.[9]

[6] RSO 1990, c. O.1
[7] *Ibid.*
[8] Control of Exposure to Biological or Chemical Agents, RRO 1990, Reg 833
[9] Exhibit 1B, Tab 5, Schedule 1

E6.3.3.1 Underground Cable Renewal

The Underground Cable Renewal segment is a continuation of the activities identified in Toronto Hydro's 2020-2024 DSP. This segment will focus on replacing obsolete primary PILC and secondary AILC underground cables at a high risk of failure with primary TRXLPE and secondary XLPE cable. These cables are typically found in the pre-amalgamation City of Toronto, especially throughout the downtown core.

PILC and AILC cables were initially installed in the downtown system due to their high reliability and long-life span. However, they are obsolete across the industry due to environmental and health and safety concerns (which includes the challenge of safely and skillfully working with lead). Major utilities are proactively eliminating lead cable, and only one PILC supplier remains (there are no longer any suppliers of AILC cables). Approximately 58 percent of all PILC cables and 93 percent of all AILC cables in the system are more than 30 years old. Aged cables are showing signs of deterioration, including pin holes, cracks, and leaks.

Toronto Hydro is planning to remove approximately 3.5 percent of PILC cable (34.9 circuit kilometres of 985 kilometres) and 5.3 percent of AILC cable (9.3 circuit kilometres of 176 kilometres) between 2025 and 2029. The cables will be replaced based on the risk level associated with each feeder. A prioritization model has been developed by Toronto Hydro to rank primary feeder cable segments based on various factors, including historical failures, cable types, number of transition splices on feeders, age and customer base. In addition, as primary cables and cable segments are being tested or replaced, Toronto Hydro will re-prioritize at-risk feeders. Where at-risk primary cable sections are identified, this will drive the replacement of the legacy type AILC cable that is connected downstream of these cable sections.

PILC cable consists of a conductor surrounded by oil-impregnated paper insulation, lead sheath and an optional linear low-density polyethylene jacket. There are approximately 985 circuit-kilometres of 13.8 kV PILC underground cable on the system. These cables were used as the primary service cable in the downtown core, connecting transformer stations to customers or Toronto Hydro owned distribution transformers (these transformers step down voltage and supply residential customers). Approximately 51 percent of all primary cable in the downtown core is PILC cable and approximately 49 percent is XLPE cable.

Figure 1 shows the distribution of PILC cable in the City of Toronto and the level of risk associated with them based on the type of cable, age, number of splices and reliability record. The highest risk cable segments (15 percent of total PILC cable length) are found both within and around the downtown core, while the medium risk cable segments (41 percent of total) are heavily concentrated within the core, and the Financial District in particular.

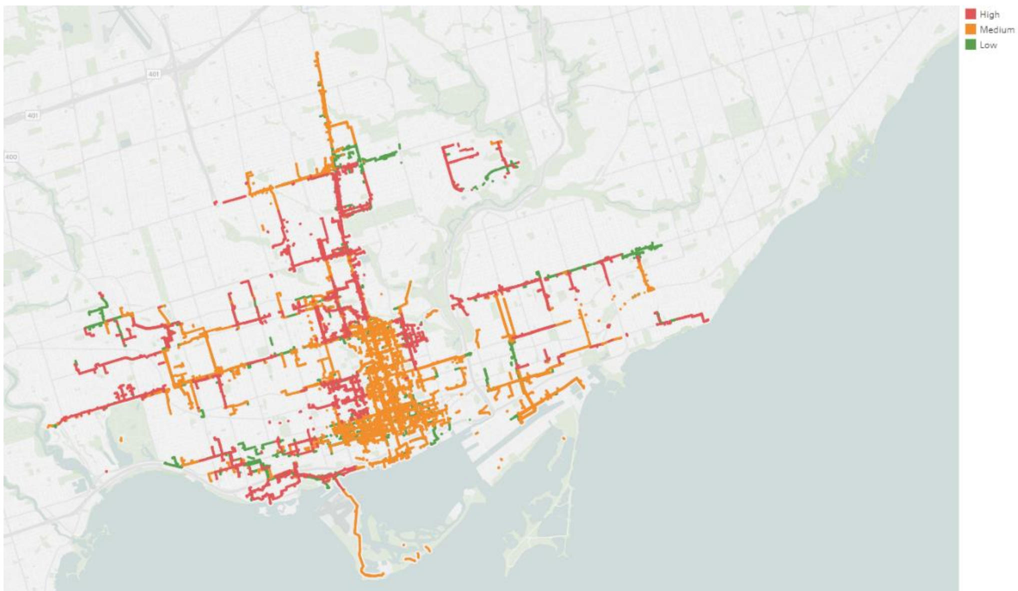


Figure 1: PILC Cable Distribution

AILC cables are found downstream of these PILC cables. They consist of a conductor (typically copper) surrounded by asbestos-based insulation and covered in a ductile lead sheath. These cables account for 40 percent of the secondary voltage connections within the secondary network system.[10]

Figure 2 represents the general distribution of all AILC cables in the city of Toronto and their level of risk based on the associated age and condition of primary assets. The majority of the AILC cable population is located in the core, whereas a small proportion is located north of the core.

[10] For more information on the Secondary Network System, please refer to Exhibit 2B, Section D2.2.3 of the Distribution System Plan.

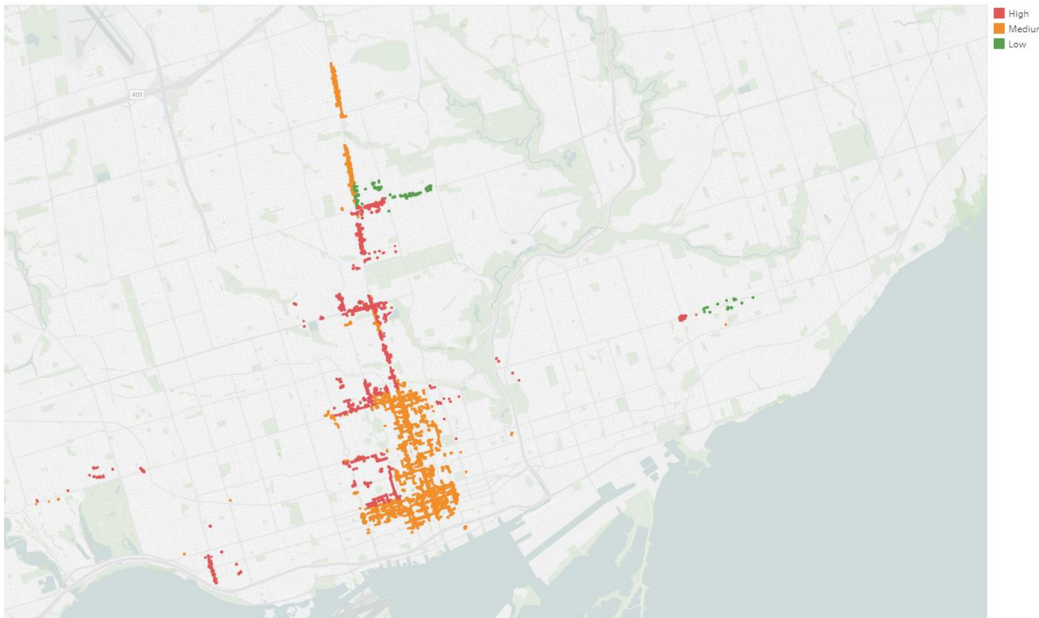


Figure 2: AILC Cable Distribution

Historically, PILC cable was used as it has good reliability record with a typical useful life of 65 years. However, the risk of failure for PILC cable increases if the PILC cable is modified. Due to the obsolescence of PILC and AILC cables, the necessary interventions and modifications to downtown feeders have unavoidably resulted in the splicing of XLPE cable into sections of PILC and AILC cable. Splicing is the process used to maintain the connectivity between two cable sections using joints for similar cable types and transition joints for different cable types. It is typically carried out when a longer cable is required, a branch is required, or part of an old cable is replaced with a new cable. This introduces non-uniformity of cable types and thus increases the risk of failure on the system as the majority of Toronto Hydro feeders with PILC and AILC cables do not consist of 100 percent PILC or AILC; instead, a mixture of cable types is common (e.g. PILC and XLPE, or AILC and XLPE).

Table 4 summarizes the programs and types of work that lead to a mix of cable types on Toronto Hydro feeders.

Table 4: Work conducted on Toronto Hydro feeders that lead to mixed cable types

Programs	Description of Work
Customer Connections (Exhibit 2B, Section E5.1)	• Customers are connected with new XLPE type cable spliced to existing PILC cable. • This also includes the addition of XLPE cable for secondary network type connections (replacement of AILC cable).
Reactive Capital (Exhibit 2B, Section E6.7)	• Cable faults or leaking cables are repaired by cutting or piecing-out faulty sections, and replaced with new XLPE cable, using splices.
Load Demand (Exhibit 2B, Section E5.3)	• Cable sections that require upgrades due to capacity limitations are replaced with new XLPE cable.
Network System Renewal (Exhibit 2B, Section E6.4)	• Circuit reconfigurations, required to achieve network stability and improved reliability, involve splicing new secondary and primary XLPE cable into existing AILC and PILC cables. • Network unit replacements include the replacement of critical AILC or PILC type cables that are connected to these units. • Cables to the most upstream cable chamber are replaced resulting in the introduction of splices.

As a result of the work noted in Table 4, lead cables become more brittle and prone to cracking, and the number of transition joints or splices increases over time. These splices create and add weak points along the cable and introduce additional failure risk to already aging cables serving many large and critical loads. Consequently, feeder life expectancy and probability of failure worsen. As the weakest point on a feeder, a cable joint may fail primarily due to mechanical stress or water ingress.[11] A fault in the joints may also impact the conductor, insulation, or sheath. For instance, the sheath of the joints can develop corrosion due to thermal stresses of the feeder, which increases the chance for moisture to seep into the joint and consequently cause a failure.

The introduction of mixed insulation types also introduces different dielectric strengths or inconsistent magnetic fields at the joints which would result in higher losses or insulation breakdown. These transition joints (splices) are critical to the continuity of the dielectric properties and magnetic field across cable sections. They require a lead sleeve for the cable section to maintain the insulation

[11] Nemati, H.M., Sant'Anna, A., & Nowaczyk, S. (2015). Reliability Evaluation of Underground Power Cables with Probabilistic Models, *The 2015 International Conference on Data Mining,* p. 37-43.

properties of PILC cable. This is to hold the oil from oil-impregnated paper and protect insulation as much as possible. If these sleeves are compromised, this can result in drying out of the impregnated paper and compromise the insulation properties. Furthermore, as cable sections age, they begin to experience thermal, environmental, or mechanical stresses. Since XLPE and lead cables have different properties, the transition joint on any given feeder experiences the most stress. For example, the Windsor TS feeder A-81-WR supplies seven large customers, and includes five transition splices and 25 lead joints, as shown in Figure 3 below. Failure at any of these splices or joints will result in an outage while crews switch customers to backup supply, which typically takes 2 to 4 hours and subsequently about 8 to 10 hours until full power is restored.

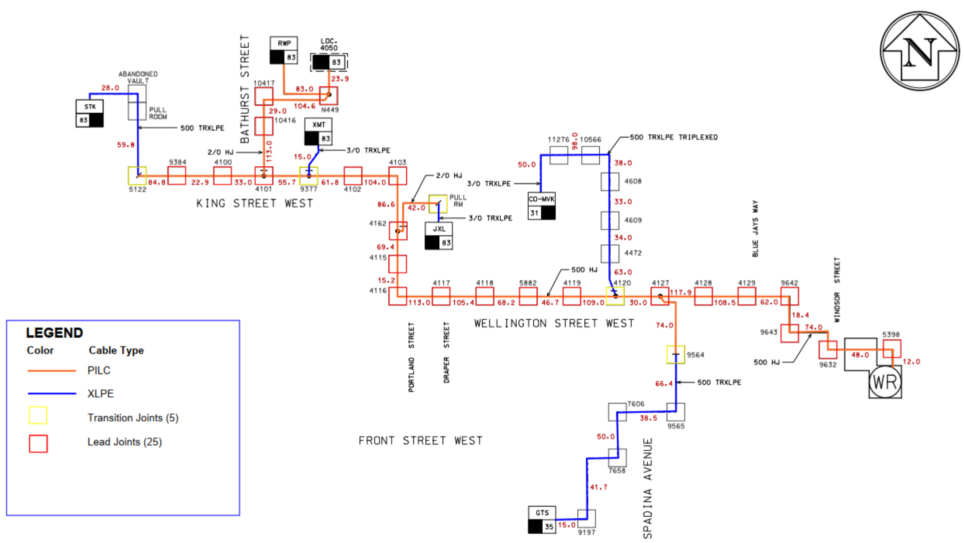


Figure 3: Schematic Feeder A-81-WR that depicts Transitional and Joint Splices

Figure 4 below illustrates examples of splices with deficiencies.

Figure 4: Sample PILC Joint with a Split Sleeve, i.e. Leaker (Left) and Collapsed Cable Splice (Right)

In addition to increased failure risk due to cable splicing, there is the risk of oil leakage from the insulation on PILC cables. Over time, due to load fluctuations and physical stresses on feeder cables, the outer covers of lead cables develop cracks, causing oil from the paper insulation to leak from the cable and pool on the cable chamber floor. On average, Toronto Hydro had to repair 30 such leaks per year between 2019 to 2022, a significant increase from the average of eight per year reported in the 2020-2024 DSP.

As shown in Figure 5 below, the failure rate of lead splices and transition joints per kilometre increases with the age of the feeder sections, i.e. the older the feeder cable and its splices, the higher the number of outages. The majority of these failures are due to moisture ingress, reduction in dielectric strength due to oil leaking from cracks and pinholes, as well as thermal stress.

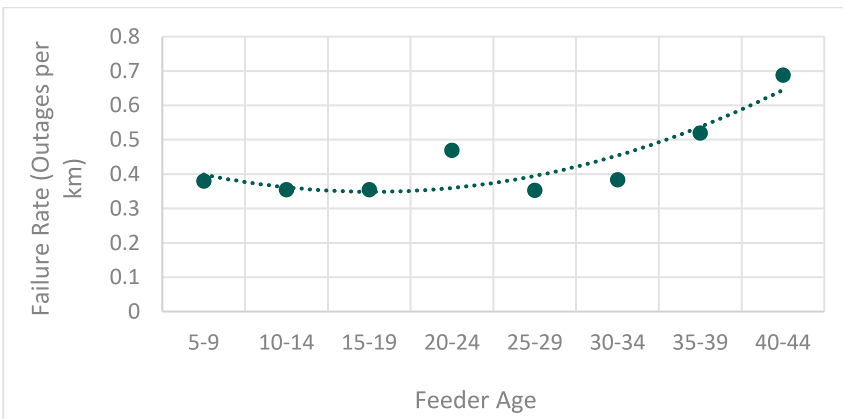


Figure 5: Failure rate of cable splices with PILC[12]

On average, there are 4 transition joints and 27 lead joints per primary feeder in downtown Toronto. By the end of 2029, given the PILC cable planned for replacement, Toronto Hydro expects to maintain the average number of transition joints at 4 and reduce the average number of lead joints to 24. Figure 6 and Figure 7 illustrate the current state of transition joints and lead joints in the system on feeders (though not all feeders are labelled therein). Figure 8 shows the comparison in number of transition splices per feeder between 2017 and 2023 for select feeders targeted for renewal over 2020-2024. The number of transition splices decreased for the four feeders already completed, while

[12] It is important to note that Toronto Hydro keeps a limited quantity of PILC cables on hand for extreme circumstances where reactive repair is required.

the fifth feeder, which has not yet been renewed, saw an increase due to work such as that listed in Table 4.

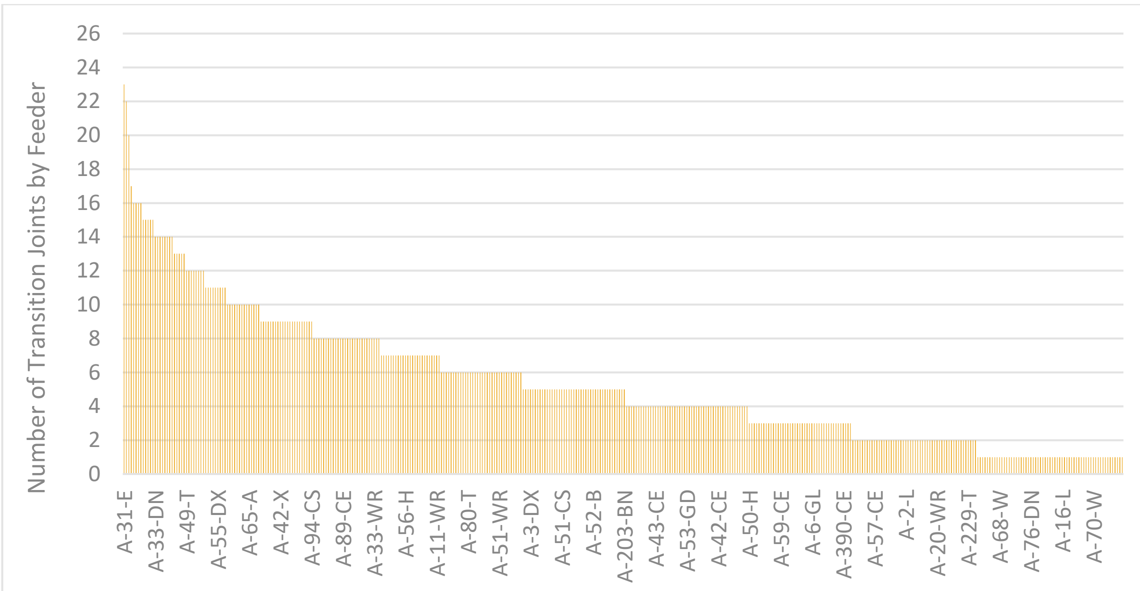


Figure 6: Transition Joints by Feeder

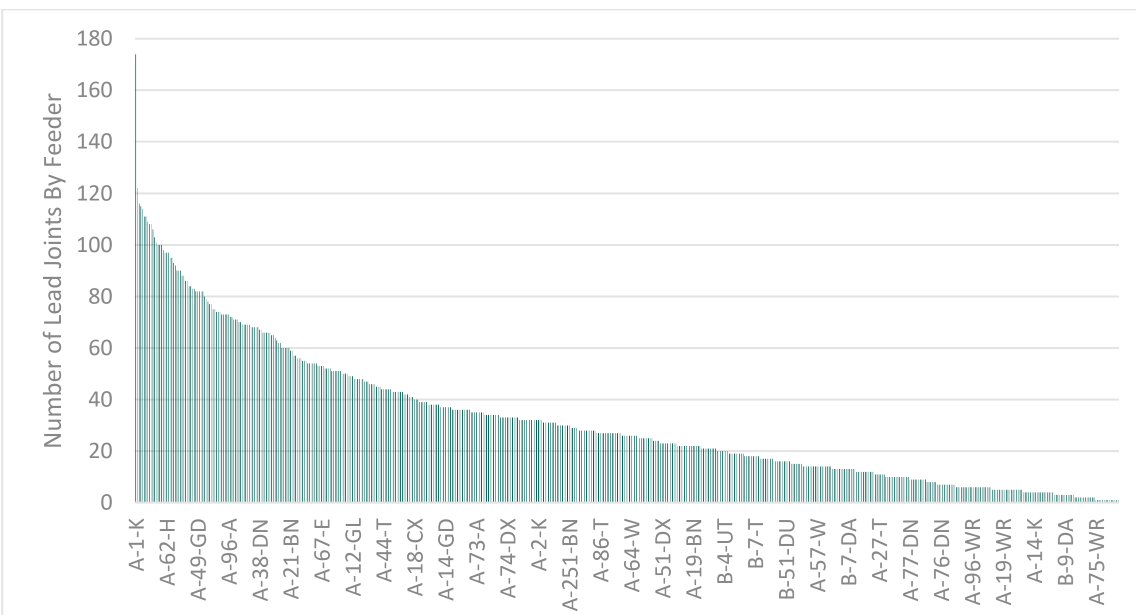


Figure 7: Lead Joints by Feeder

Figure 8: 2017 vs. 2023 Comparison of Transition Splices on feeders targeted for renewal over 2020-2024, with all except A33E now completed (A33E planned for 2024).

As shown in Figure 9, there are on average 44 reported cable or splice related failures per year, including on average 22 failures per year related to splices.

Figure 9: Number of PILC Cable/Splice Failures per Year

There were a total of 312 cable and splice failure incidents reported between 2016 to 2022 with an increasing trend of 55 incidents per year in years 2018 and 2019. The number of incidents per year has gradually reduced between 2019 and 2022 to 40 incidents per year. As per Figure 5, the number of failures per km rises with cable age. Quantitatively, this trend aligns with the qualitative observation by field personnel of the rise of failures as more splices are introduced while cable sections age.

Cable failures affect a wide range of customers, whose configuration of connection to the system depends on the feeder and the supply location and not necessarily customer type. Figure 10 below illustrates this using seven sample feeders. This segment aims to target feeders with large loads, such as A-81-WR, and introduce uniformity of cable by proactively replacing a large section of cable especially in the downtown core. This aligns with the customer engagement results where customers (especially large customers) prioritize reliability. Large multi-residential buildings are considered as large commercial customers here since minimal cable renewal investments will impact many end use customers.

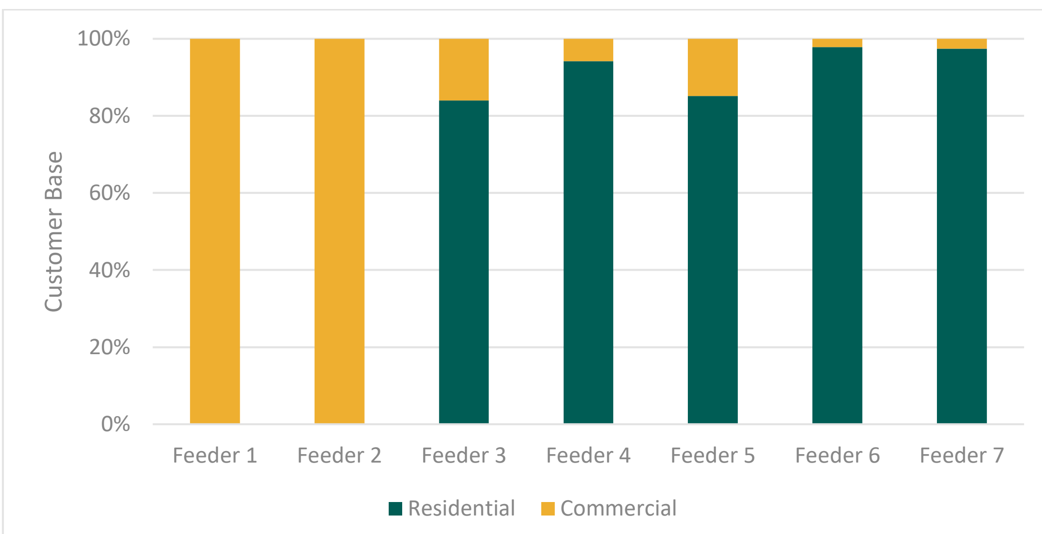


Figure 10: Composition of Customer Type of Circuits with PILC Cable

Lead-based cables (e.g. AILC and PILC) also need to be removed from the system due to a large functional obsolescence factor. Lead splicing typically requires highly qualified and trained individuals. Many utilities are facing a challenge training personnel with respect to lead splicing techniques. The skillset in the workforce is diminishing as lead cable is not actively introduced into the system. Furthermore, PILC cable is only supplied by one North American manufacturer at this time and a procurement problem may arise in the near future, while AILC cables are currently obsolete and are no longer supported by any manufacturers. Although Toronto Hydro stocks minimal PILC cable, it is not actively introduced into the system and primarily used for reactive replacements. There is also a risk in maintaining a large population of PILC cable in the long term if PILC cable becomes unavailable. This is because some segments of PILC cable cannot be replaced reactively with XLPE and TRXLPE cable due to duct or cable chamber size limitations or the condition of the underlying civil infrastructure. In recent years, due to lack of manufacturers it has been challenging to source splicing materials required for PILC joints and transition joints and as such, construction standards has been revised to limit PILC cable installation and use polymeric XLPE and TRXLPE cables where feasible. As noted above, this increases failure risk if these non-homogenous feeder types are not minimized.

These cables present both safety and environmental risks. Lead is a designated substance as per Ontario Regulation 490/09 (see section 10) and exposure should be minimized to mitigate the health risks. The risks of working with this substance alone is a potential safety hazard as lead needs to be exposed to high temperatures to complete a lead splice. This can create airborne fumes increasing the occupational and environmental exposure. Further, PILC cables manufactured prior to 1986 may contain PCBs within the oil. Toronto Hydro is committed to mitigating the risks of oil leaks containing PCBs. Leaking PILC cables also present risks to crew and public safety as the likelihood of arc flashes due to the deterioration of the insulation is high. Arc flashes are dangerous to crews and pose a safety risk to the public if leaking oil becomes ignited. Leaking oil is a sign of pending cable failure.

In addition to removing obsolete, lead-based cable, Toronto Hydro plans to install fiber optic cables in support of an online cable monitoring program. The program will utilize distributed temperature sensing technology (“DTS”) to obtain a continuous temperature profile of the fiber optic cables that are placed alongside underground cables. It will also provide partial discharge information of underground cables. Partial discharge is a common sign of insulation breakdown on underground cables and connections or weak spots in cables which eventually result in cost-intensive repairs and prolonged outages. The benefits of this technology are the following:

1. Increased observability on feeders by providing real time thermal loading of cable segments and thus allow operations and planners to assess feeder loading and available capacity for enhanced optimization of in-service assets.
2. Improved reliability as it would allow for proactive measures to be taken on cables such as identifying and replacement of at-risk cables before failure.

3. Reduce operating costs and planned outage times as it could defer offline cable testing activities.

The online cable monitoring technology depends on the presence of fiber optic cables along the cable route for monitoring and currently not all feeder routes have fiber optic cable. Through this segment, Toronto Hydro proposes installing 5 km of fiber optic cable over the 2025-2029 period in addition to the PILC cable replacement in routes where there is no existing fiber optic cable present. This would expand the fiber optic cable network and enable deployment of online cable monitoring to additional sections of the distribution system. The information provided by online cable monitoring technology could be used to enhance cable risk assessment and replacement prioritization processes in the future.

E6.3.3.2 Cable Chamber Renewal

The Cable Chamber Renewal segment will invest in the structural integrity of Toronto Hydro's high risk, poor condition (HI4 and HI5), and aging population of cable chambers by rebuilding the whole chamber or roof, or abandoning the chamber. Cable chambers house, protect, and provide access to underground electrical equipment across the city. There are approximately 10,657 cable chambers in Toronto Hydro's underground distribution system, of which approximately 74 percent are in the downtown area. These chambers hold up to 29 circuits each, supplying anywhere from 3,500 customers of different types and sizes, down to a few large industrial or commercial customers (e.g. financial institutions, hospitals).

Cable chambers have a useful life of 65 years, while chamber roofs have a useful life of 25 years, meaning that the roof will require a rebuild at least once during the useful life of the chamber as cable chambers are impacted by deterioration drivers such as road salts and vehicle loading. Figure 11 shows the cable chambers age demographic, as of 2022, for all cable chambers and roofs. Approximately 2,208 cable chambers are past their useful life and 6,643 cable chamber roofs are past their useful life.

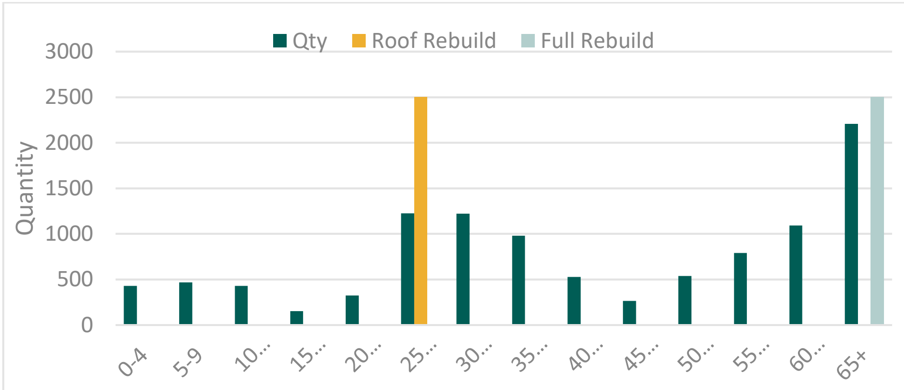


Figure 11: Cable Chambers Age Demographic

Toronto Hydro inspects cable chambers and cable chambers roofs on a planned 10-year cycle. The growing backlog of aging cable chambers is reflected in the observed condition of the assets. For many of its major assets, including cable chambers, Toronto Hydro performs asset condition assessment ("ACA"), in which the condition of each asset is assigned a health index ("HI") band from HI1 to HI5, where HI5 indicates the worst condition. For these same assets, the utility can then also project future condition (i.e. HI band) assuming no intervention.[13] Figure 12 below shows the asset condition of the 10,657 cable chambers in Toronto Hydro's distribution system as of 2022 and the projection for 2029. The data indicates that 592 cable chambers have condition classified as HI4 or HI5 and will require rebuild in the near-term. Furthermore, Toronto Hydro projects that there will be 1,113 cable chambers in HI4/HI5 band by end of 2029 without investment.

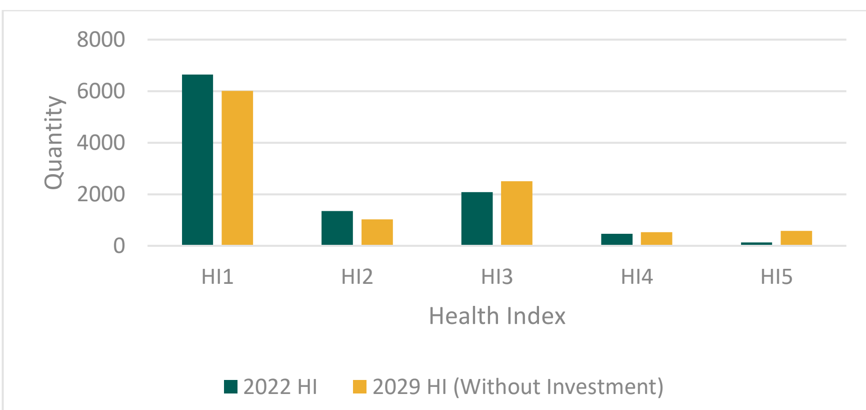


Figure 12: Cable Chamber HI Distribution (Actual and 2029 Forecast)

[13] See Exhibit 2B, Section D3, Appendix A for more details on Toronto Hydro's ACA methodology.

Depending on the severity of issues, Toronto Hydro ensures the time of rebuild is determined based on a holistic review of the structural condition of the chamber (even if it is classified as HI5). This means a cable chamber may require a reactive rebuild or temporary repairs to mitigate safety risks which would allow for a planned rebuild in the future.

Figure 13 below shows the high concentration of HI4 and HI5 condition chambers in the downtown core, where, as mentioned above, the chambers tend to carry a high concentration of circuits serving thousands of customers, or large customer loads. Should a chamber or chamber roof collapse to any extent, the equipment in the chamber could be damaged, leading to a potentially lengthy outage for the aforementioned customers.

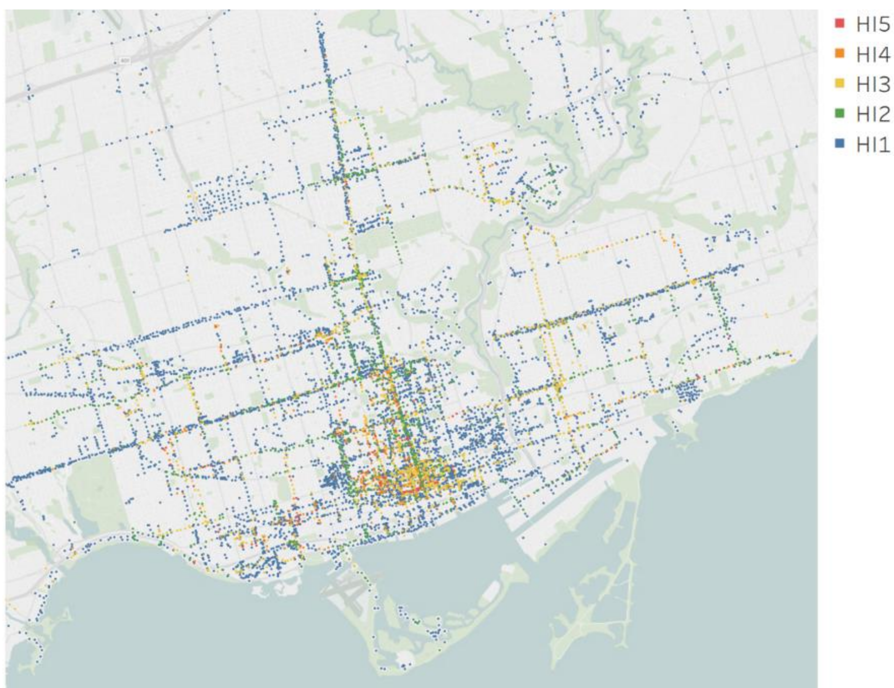


Figure 13: Cable Chamber Locations and Conditions

Of equal or greater concern is the risk to crew and public safety posed by a failing cable chamber. In areas of high vehicular or foot-traffic especially, a structurally unsound chamber or roof can create hazards to the public. The collapse of a chamber or chamber roof could have more severe consequences for the public or for crews working in the chamber. Figure 14 below shows an example of a severely deteriorated cable chamber roof.

Figure 14: Cable Chamber Roof in HI5 Condition (Left), and Roof Inside View (Right)

The images shown in Figure 14 are an example of a cable chamber with a reduced neck which is common when the City rebuilds or regrades roads. In this situation, when the asphalt was removed, a hole was discovered. This is very dangerous especially if the hole or deteriorated structure is covered by newly paved road.

Depending on the specific site, addressing a HI4 or HI5 condition chamber will include:

- **Full rebuild:** rebuilding the cable chamber civil structure, including its roof and duct banks, and involves some cable replacement; or
- **Roof rebuild:** rebuilding only the roof.
- **Cable Chamber Abandonment:** if the cable chamber is in a condition such that it cannot be brought to the current standard, it will be abandoned and a new chamber will be rebuilt beside it.

In addition to rebuilds, Toronto Hydro also plans to continue proactively replacing potentially hazardous cable chamber lids. Deteriorated cables running through cable chambers can fail, potentially causing arcing and igniting gases, which then can create a powerful shock wave. These shock waves can dislodge a chamber lid in a violent manner, ejecting it into the air and creating a serious public safety hazard. Since 2018, Toronto Hydro has recorded 26 incidents related to cable chamber lids, as shown in Figure 15. The utility is proactively replacing lids on cable chambers with an energy mitigating lid design to mitigate this ejection risk. Since 2020, Toronto Hydro has replaced 470 cable chamber lids with energy mitigating lids and plans to replace another 2,800 cable chamber lids over 2025-2029. The increased pace is required to address the safety hazard associated with the higher risk locations in a timely manner.

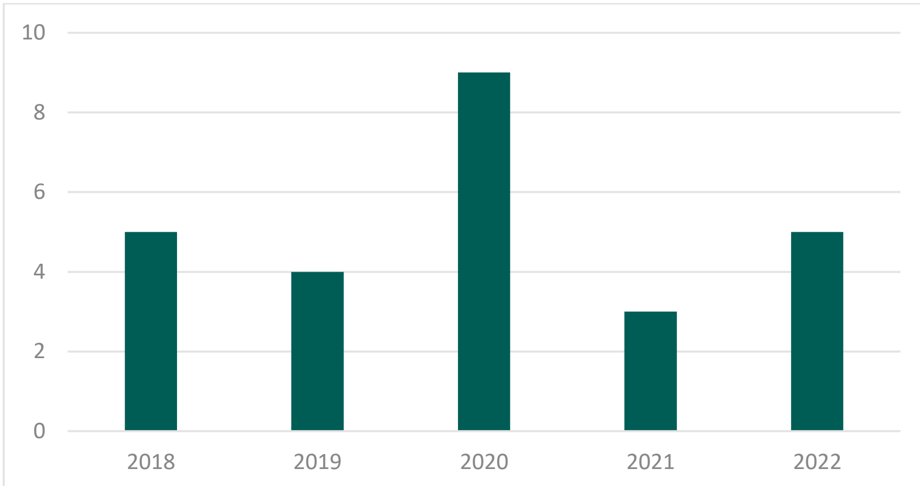


Figure 15: Number of Lid incidents

E6.3.3.3 Underground Residential Distribution ("URD") Renewal

This segment aims to replace deteriorating and obsolete URD assets that could negatively impact system reliability. These assets include: vaults, switches (including FCIs), and transformers that form part of the URD system. As per Toronto Hydro's customer engagement results, residential customers indicated that reliability is a top priority.[14] As such, specific areas of the URD system will be targeted for renewal in this segment to support maintaining the reliability performance of the URD system.

Introduced in the 1990s, the URD system was intended to replace the 4 kV overhead system supplying residential customers in the downtown area. The URD system is comprised of redundancies via main loops and sub-loops to add a level of robustness by isolating sections of the feeder.

The main underground system configurations are either radial or looped. However, system types and configurations are sometimes mixed to provide improved reliability or flexibility when repairs are required, as is the case with URD. In the URD system, primary cables, switches, and distribution transformers are placed underground while most secondary voltage connections remain overhead. This system only appears in limited areas throughout the pre-amalgamation City of Toronto, as seen in Figure 16 below.

[14] *Supra* note 9

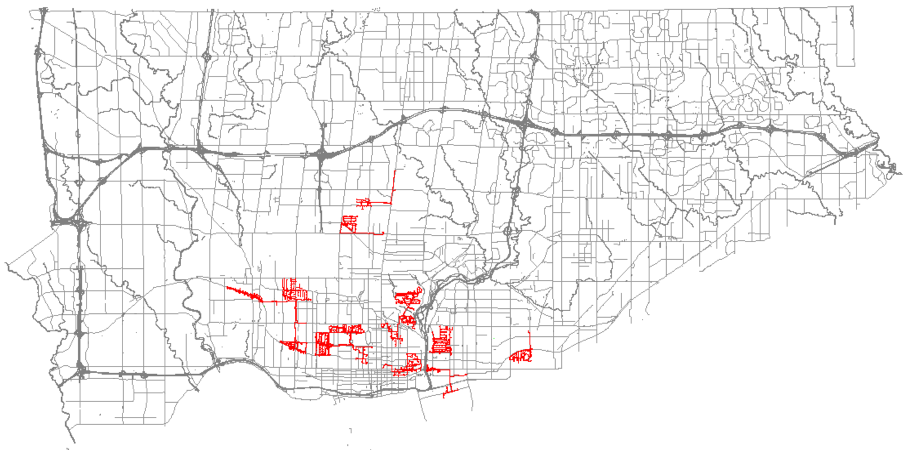


Figure 16: Map of Toronto with URD Feeders

The URD has three distinct feeder sections: (i) a main-loop; (ii) sub-loops; and (iii) branch circuits (or sub-sub-loops). Figure 17 below provides a simplified example of the configuration of a downtown URD feeder. The main loop is fed by the main feeder or standby feeder from the stations and interconnects the 600A switching vaults supplying an area, allowing for the isolation of the sub-loops and branch circuits in the event of a fault. The sub-loops start at the 600A switching vaults on the load side and end at the 200A switching vaults, where the branch circuits split off in multiple directions. URD transformers are connected to the primary feeder sub-loops or branch circuits, which feed individual or groups of customers.

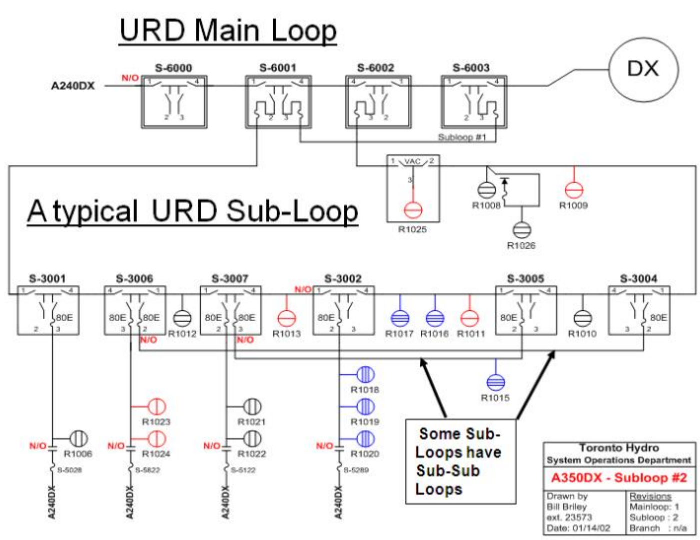


Figure 17: Typical URD Feeder Configuration

The reliability performance of URD system have been relatively stable over the last 5 years as shown in Figure 18 and Figure 19. Defective equipment was the largest contributor to annual customer reliability representing about 70 percent and 80 percent of CI and CHI, respectively. Targeted renewal of URD assets is required to support a stable reliability trend (i.e. maintain reliability performance).

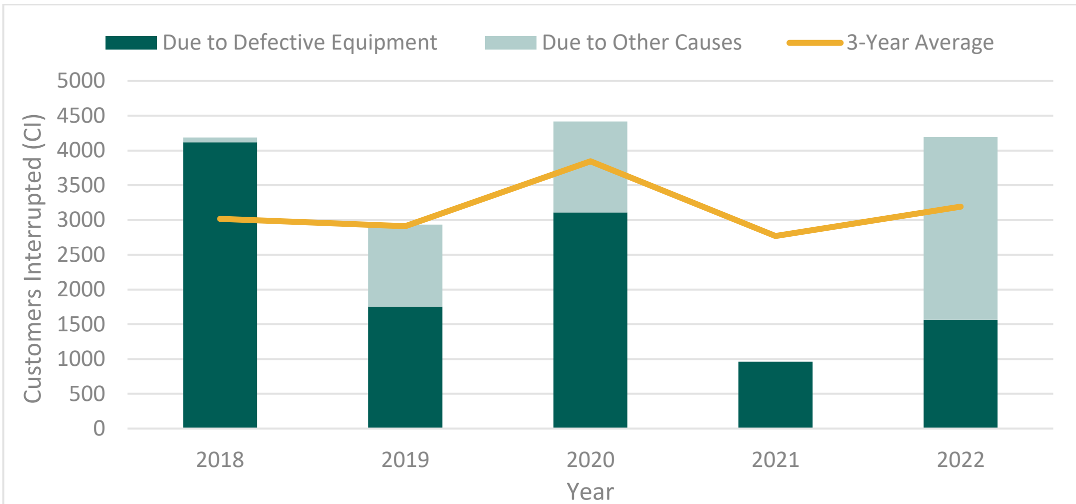


Figure 18: Customers Interrupted — URD System

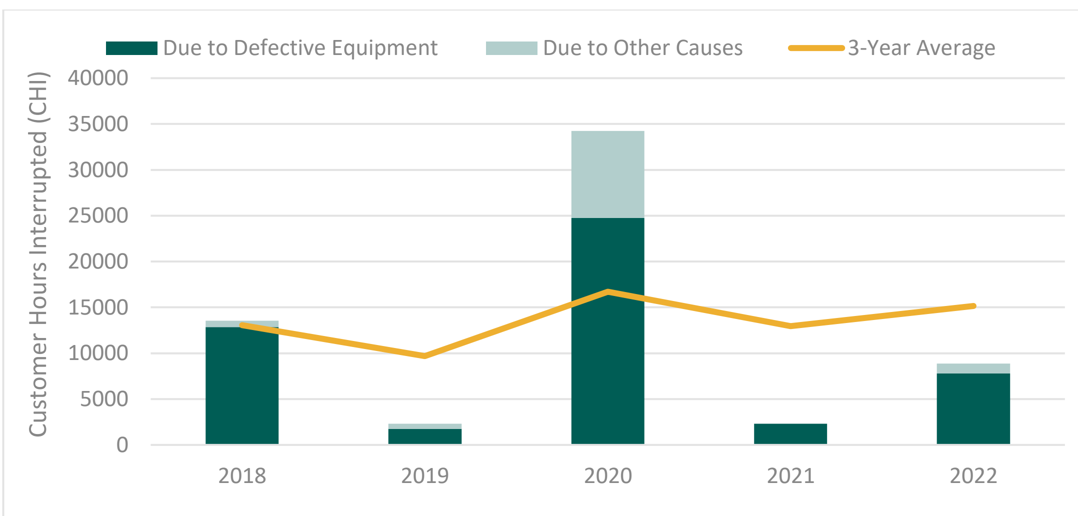


Figure 19: Customer Hours Interrupted — URD System

Figure 20 below compares the average CAIDI of URD system with 13.8 kV underground radial system over the last 5 years.[15] As can be seen from the figure, the average time to restore service in URD is

[15] Customer Average Interruption Duration Index

higher than underground radial system. This is mainly due to the fact that determining the source of an outage in the URD system can be time consuming due to the complex set-up of loops. The design of the URD includes FCIs, which help find the locations of faults in this complicated configuration so that customers can be restored in a timely manner. Of note, the average outage duration in URD system are on slightly increasing trend over the last five years. This is due to the corrosive environment in the switching vaults, where most of these FCIs are located leading to mechanical failure, and associated incorrect readings from the FCIs while fault locating.

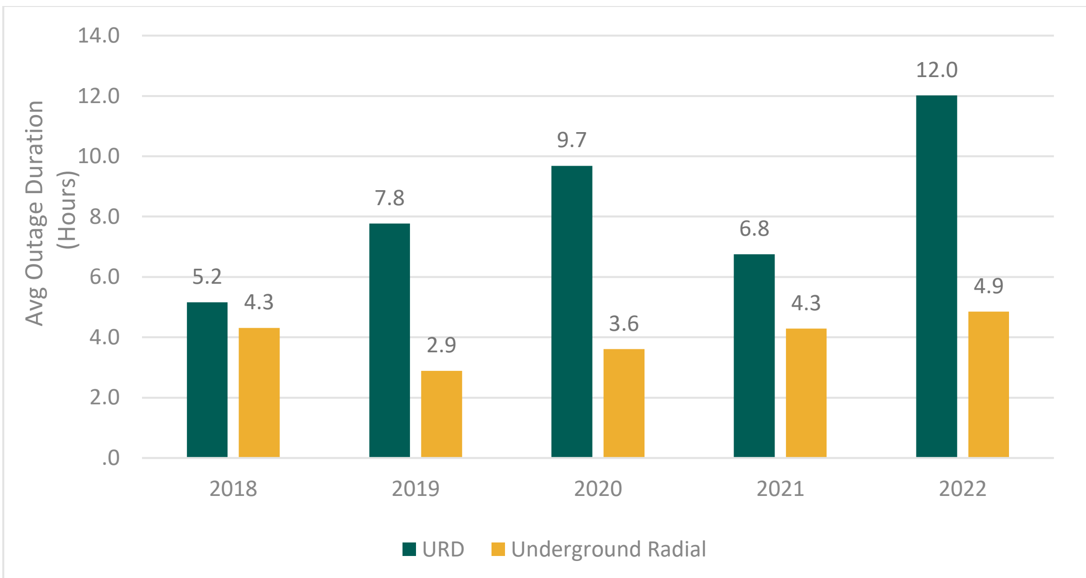


Figure 20: Average Outage Duration – URD vs Underground Radial System

Maintenance and inspection of the URD vaults are performed twice a year, one inspection for the civil condition and the other for the electrical condition. As part of this work, the vaults are inspected to ensure the integrity of the electrical equipment, structure, and security. This includes a thermograph of all electrical assets, cleaning the entire vault and reporting any vaults that require follow-up repairs. The results of the inspections show that URD switching vault equipment tends to be in poor condition due to rust on the cabinet and corrosion on the connectors. Figures 21 and 22 below provide the URD electrical and civil inspections results, highlighting the most common types of deficiencies identified and found over the past three years (i.e. 2020 to 2022).

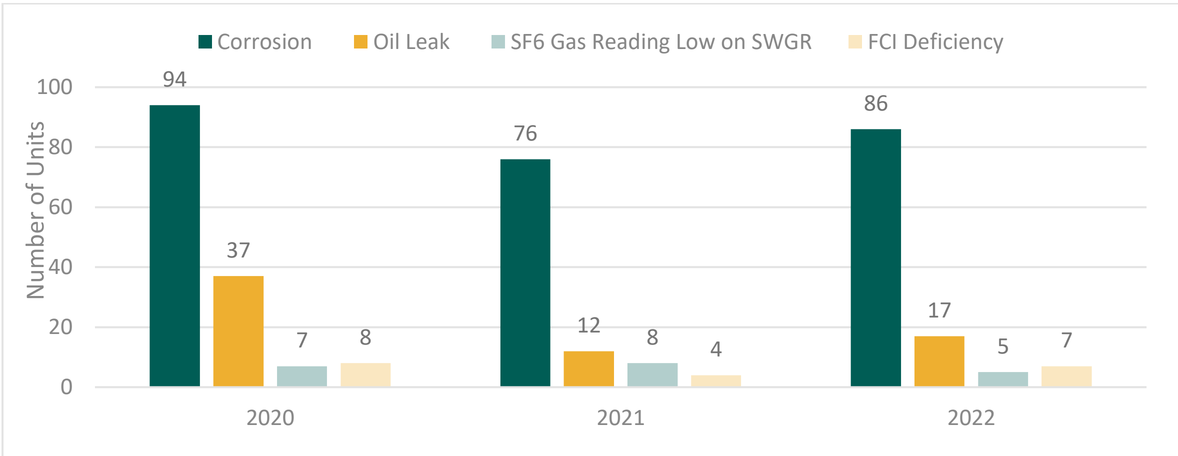


Figure 21: URD Electrical Deficiencies

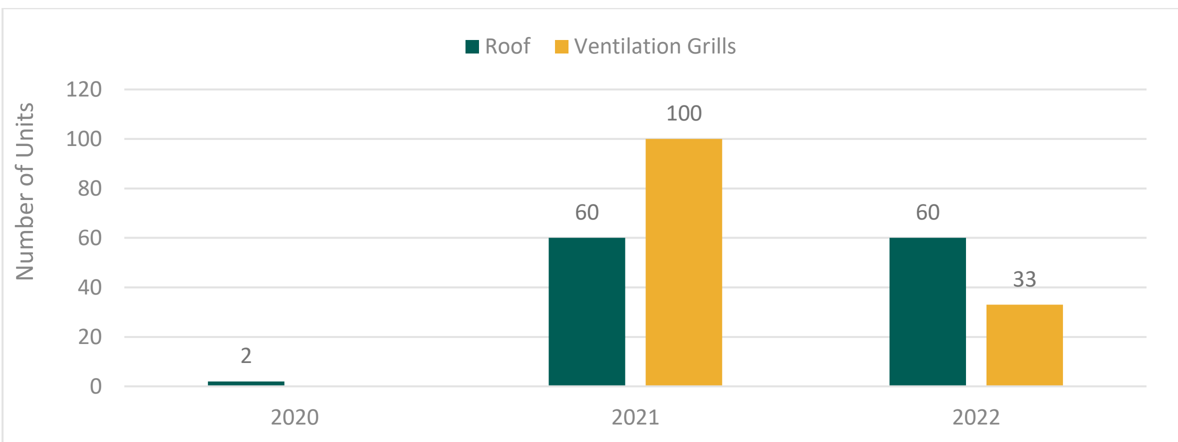


Figure 22: URD Civil Deficiencies

As per the URD electrical inspection data in Figure 21, the main issues are the recent rising number of deficient switchgears with low SF6 readings and malfunctioning FCIs, as well as corrosion of electrical equipment. As per the civil inspection data in Figure 22, URD civil deficiencies have been steadily increasing. These deficiencies increase the risk of failure of URD assets and as a result, the renewal process is driven by failure risk. The following sections describe the state of three main assets of the URD system: URD vault roofs, URD switches (including FCIs), and URD transformers while considering the above-mentioned deficiencies.

1. URD Vault Roof

Civil conditions of URD vaults deteriorate over time due to exposure to harsh environments as a result of severe weather, salt, or road construction. Some commonly found structural deficiencies caused by asset aging and environmental factors are exposed roof and wall rebar, corroded I-beams and cracked roof and walls. Such deterioration includes corrosion, spalling of concrete, and cover rusting which pose a potential safety hazard for the public and field crews. Compounding this situation, the ventilation design and equipment layout inside the vault have allowed dirt to accumulate on top of switching equipment, causing corrosion of components such as elbow terminations. This degradation of the URD vaults increases the failure risk of the assets within it. Illustrative examples of the aforementioned types of roof cracks are shown in Figure 23 and Figure 24 below.

Figure 23: URD Vault with Deficient Roof

Figure 24: URD Vault Deficient Roof Temporarily Repaired with Asphalt

The useful life of a URD vault is 60 years while the roof is 25 years. Therefore, the roof is typically rebuilt at least once during the life of the vault. Figure 25 below shows the age distribution of URD vaults. The majority of vault roofs of the URD vaults have reached or passed their useful life, and as such are considered for rebuild.

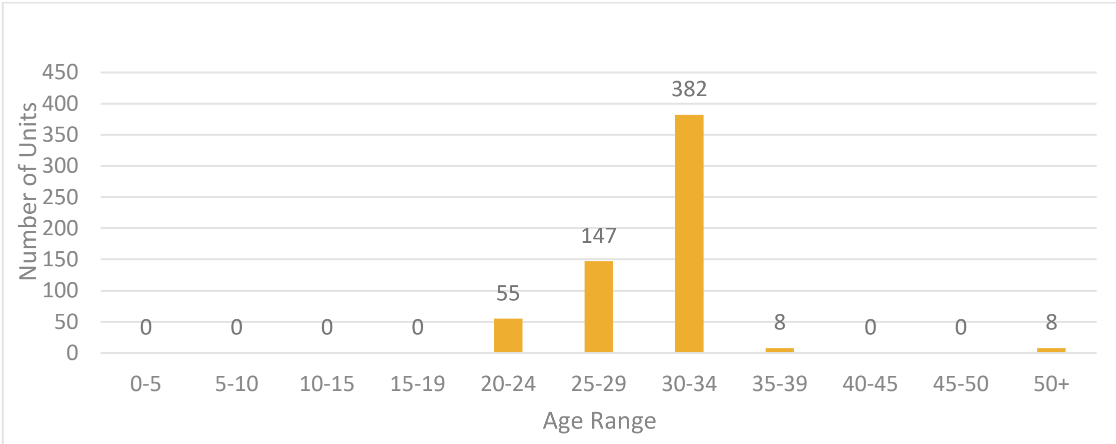


Figure 25: URD Vaults Age Distribution

Figure 26 presents the HI distribution (current and 2029 forecast) of the URD vaults. At the end of 2022, 8 of the URD vaults exhibit at least material deterioration (HI4/HI5 condition). The HI4/HI5 volume is forecasted to grow to 13 in 2029 without investment. It is important to note that the ACA model is a measure of the health of the entire vault asset, and that even vaults in HI1 or HI2 condition may have roof deterioration that needs to be addressed. To alleviate the risks posed by deteriorated vault roofs, Toronto Hydro plans to address 4 URD vault roofs between 2025 and 2029.

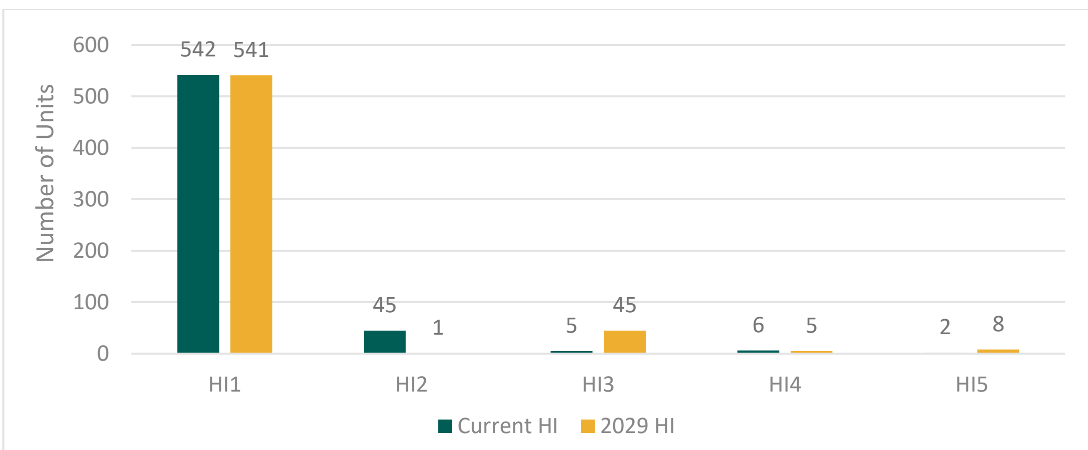


Figure 26: URD Vaults HI Distribution (Actual and 2029 Forecast)

Given the deficiencies being identified, Toronto Hydro is developing a new roof design that minimizes the amount of dirt, debris, and water that accumulate directly on electrical equipment. The new design will be similar to the compact radial distribution ("CRD") underground vault, which typically supply small retail, apartment, and commercial office buildings. In addition, the new design will improve safety by reducing the potential of tripping incidents, and create a larger opening for the replacement of electrical equipment. When rebuilding a vault roof, the electrical equipment will be assessed and upgraded to the latest standards if existing equipment is in poor condition or obsolete.

2. URD Switches

Switches used in URD are submersible, 200A and 600A, SF6-insulated switches which are operable from above grade. SF6 load break switches are designed and constructed to provide safe and reliable switching. Using SF6 for insulation and arc interruption eliminates space, weight and maintenance costs. The switch provides improved interrupting and open gap performance, while at the same time eliminating most hazards associated with vacuum or oil filled equipment. In the URD system, the switches are mounted on stands close to the vault wall for ease of operation, cabling, and space utilization.

As of the end of 2022, these switches are deteriorating in condition. A large portion do not have stainless steel enclosures and are experiencing gas leakage inherent to the former design of the bolted viewing window, as shown in Figure 27 below.

Figure 27: Example of a SF6 Switch with a "Low SF6" Reading

Due to the design and equipment specification of URD 200A and 600A switching vaults, they do not contain an available heat source, such as a transformer, that would promote air circulation. As a result, non-stainless steel switching equipment installed in those vaults are experiencing accelerated corrosion due to exposure to stagnant moisture. Compounding this situation, the ventilation design and equipment layout inside the vault have allowed dirt to accumulate on top of switching equipment, causing corrosion of components such as elbow terminations and supports or support beams. An example of a corroded support beam can be seen in Figure 28.

Figure 28: Example of Switch Supports that have rusted

The 200A SF6 switches are used to switch load as part of the sub-loop system. They also support 80E SF6 power fuses, which are used for the protection of branch circuits in the URD and are no longer manufactured. As such, there are limited 80E power fuses in Toronto Hydro inventory. A picture of the 80E power fuse is provided in Figure 29. In this regard, the switches are functionally obsolete, as they are no longer supported by the original manufacturer and no spare parts are manufactured or available. Replacement of both the fuse and switchgear is required to provide the adequate protection for branch circuits.

Figure 29: 80E Power Fuse

Figure 30 presents the HI distribution (current and 2029 forecast) of the URD submersible switches. At the end of 2022, five of the URD submersible switches were exhibiting at least material deterioration (HI4/HI5 condition) and this is forecasted to grow to eight in 2029 without investment. To reduce the risks posed by deteriorated and obsolete submersible switches, Toronto Hydro plans to address four units between 2025 and 2029.

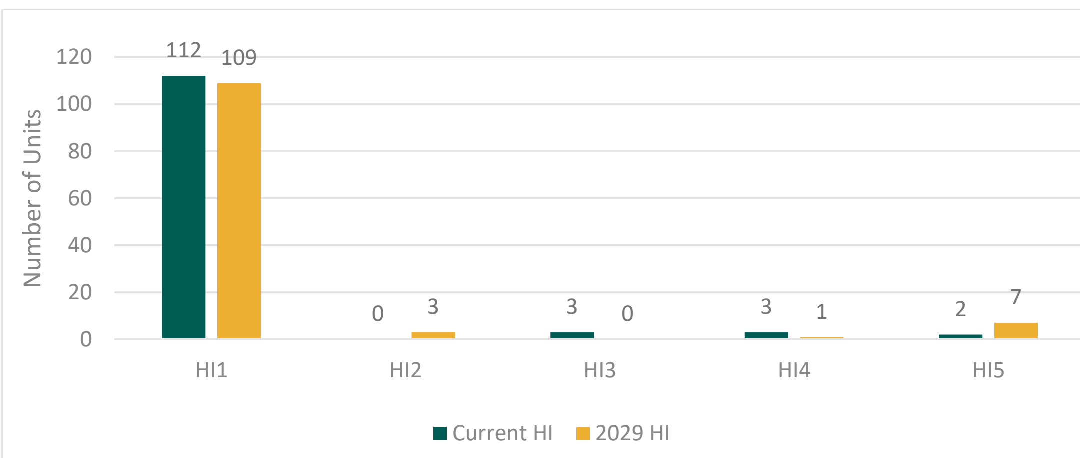


Figure 30: URD Submersible Switches HI distribution (Actual and 2029 Forecast)

In addition, several FCIs used in the URD system and manufactured as recently as 2017 are showing severe signs of corrosion. Some of the units failed to reset upon normal current restoration, giving misleading indications. Recent investigation showed broken internal wiring caused by corrosion and corroded current transformer (“CT”) laminations due to water ingress (See Figure 31 below)

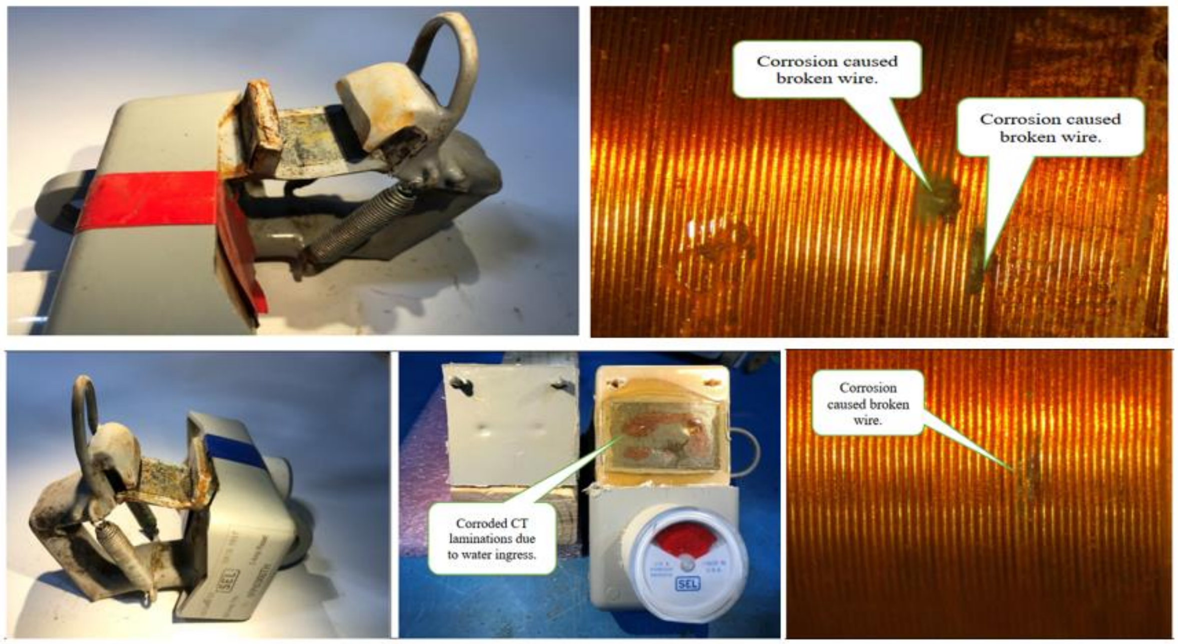


Figure 31: Teardown of the FCI units revealed water ingress caused corrosion in the CT resulting in broken wires

Given malfunctioning FCI is a contributing factor to long duration outages on the URD system, over 2025-2029 Toronto Hydro plans to replace 375 deteriorating and obsolete FCIs with the latest standards, targeting URD feeders with poor reliability performance.

3. URD Transformers

The main type of transformers used in the URD system are submersible transformers in URD vaults. The standard rating for a single phase URD transformer is 167 kVA while the three phase URD transformers range from 150 kVA to 750 kVA. URD transformers are connected to primary feeder sub-loops or branch circuits, which feed individual or groups of customers.

URD transformers are exposed to harsh environments causing deterioration, with moisture being the most destructive element as it can lead to corrosion (see Figure 32). Corrosion of the transformer tank can lead to oil leaks into the environment and low transformer oil levels, which can lead to catastrophic failure. This presents a safety risk to the public and Toronto Hydro employees, in addition to reliability and environmental impacts.

Figure 32: Examples of URD Transformers Exhibiting Corrosion on Lids and Oil Leaks

Figure 33 shows the current and forecast (without investment) HI distribution of Toronto Hydro's URD transformers. As of the end of 2022, 12 URD transformers exhibit at least material deterioration (i.e. HI4 and HI5) and, without investment, this number is expected to increase to 92 by the end of 2029. In order to mitigate the expected increase in environmental, safety, and reliability risk of this asset population, Toronto Hydro plans to replace 17 URD transformers over 2025-2029.

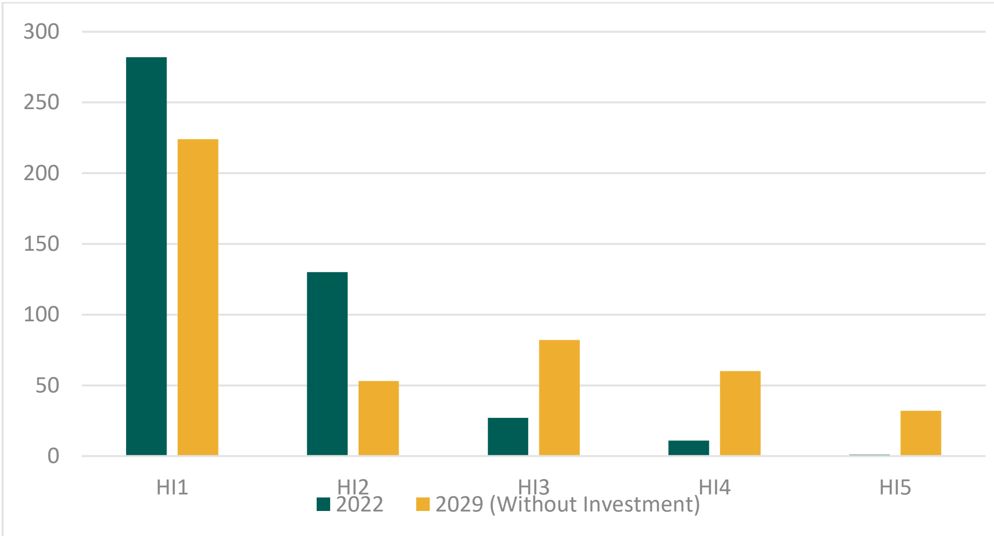


Figure 33: URD Transformer Asset Condition as of 2022 and 2029 (without investment)

As the URD vaults, transformers, and switches approach the end of their useful life, related equipment and civil infrastructure need to be updated to mitigate failure risk. Toronto Hydro will replace the roof vaults with a newer design that reduces the dirt, debris, and water entering the vaults, improves safety by reducing tripping incidents and creates a larger opening for replacing old switches. Along with roof rebuilds, the utility will replace electrical equipment such as transformers or switches within the vault with the equivalent latest standard. Toronto Hydro will also replace submersible with the new generation of SF6-insulated switches which have stainless steel enclosure to prevent premature rusting and degradation of the cabinet. Finally, the utility will replace FCIs prone to malfunctioning with new FCIs to speed up the outage restoration process.

E6.3.3.4 Underground Switchgear Renewal

The Underground Switchgear segment is driven by the failure risk of key assets that negatively impact reliability and safe operation within the downtown core. Historically, these assets have shown high reliability but have now become obsolete or pose a risk to the public. This segment aims to reduce failure and safety risks associated with legacy underground switchgear (see Figure 33) that are obsolete, past their useful life, in poor condition, and prone to failure. Failure can occur due to various factors such as age or repeated use over time, which results in breakage or failure to operate.

Figure 34: Example of Legacy Switchgear

In the 1960s and 1970s Toronto Hydro installed large transformers with underground switchgear in customer-owned vaults. Toronto Hydro owns this equipment, which feeds apartment buildings, educational facilities, and community centres. This underground switchgear is air insulated and used to provide primary supply to transformer vaults from two incoming primary feeders (one normal and one standby). Toronto Hydro has stopped installing this type of switchgear and considers them to be functionally obsolete equipment designs as they are no longer produced or supported by the manufacturer. The existing switchgear population is aging and becoming harder to maintain as spare parts for equipment repairs are not available, making it a challenge for Toronto Hydro to achieve alignment with current maintenance and inspection practices. Going forward, the lack of spare parts precludes long term maintenance as a viable option to extend the service life of these assets.

As of 2023, there are 484 underground switchgear installed in the system. Figure 35 shows the current (2022) and forecast (2029, without investment) ACA for this asset group. The data indicates that six underground switchgear are categorized as having HI4/HI5 conditions and will require replacement in the near-term. While this is a relatively small number of assets (about one percent of these switchgear) with at least material deterioration, this is expected to grow significantly to 89 units (18 percent) by the end of 2029 without investment.

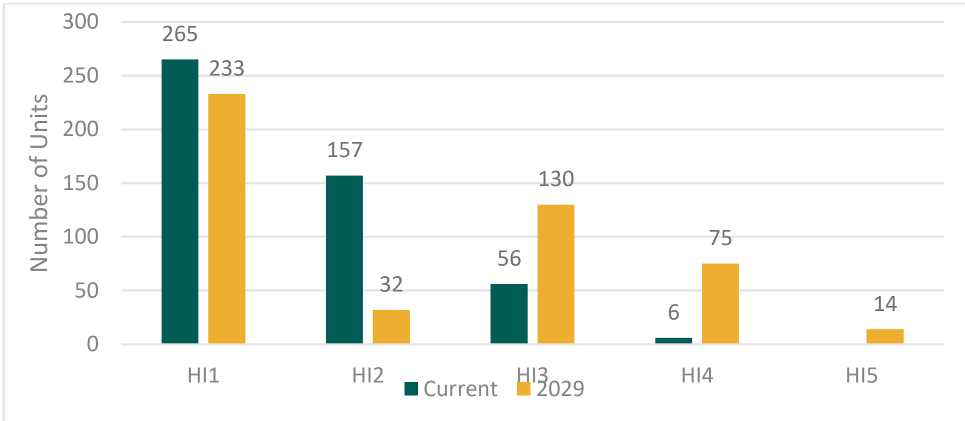


Figure 35: Underground Switchgear ACA distribution

Over the past five years from 2018-2022 work requests related to legacy switchgear have risen from 75 in 2018 to 257 in 2022. While much of this increase is due to the lowest priority work requests (P4), which require monitoring to ensure the issue does not worsen, higher priority work requests (PI and P2) have also been higher in recent years, as shown in Figure 36 below.

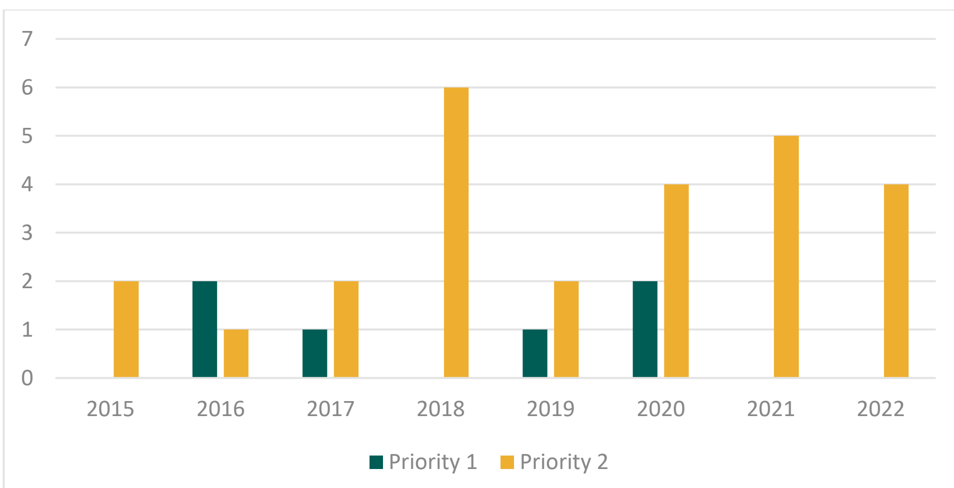


Figure 36: Underground Switchgear related Work Requests (High priority requests)

In the event where switching is required to isolate a customer or move the customer from one feeder to its standby, failed or defective legacy switchgear units may not operate as intended. This failure will result in either the delay of planned work until the switchgear is repaired or, in the event of a failure of the normal feeder, the customer will be without power for a prolonged duration as the switches are not useable. Customers supplied from the transformer vault with underground switchgear will be affected with the longest outage, but other customers on the feeder will be impacted as well due to the additional time required to isolate the faulted switchgear.

Failing legacy switchgear assets can potentially put the safety of customers and Toronto Hydro employees at risk. The inherent safety risk of switches not properly opening or failing to close entirely create an arc safety risk. Although no arc safety incidents have yet to be reported, as these switchgear age and further work request desk issues are recorded, the likelihood of having an arc safety incident will increase. Some of these legacy underground switchgears are non-submersible and could be damaged by water ingress into the vault as recorded by two incidents in 2018 and 2019. Since 2017, there have been three incidents related to underground switchgear failure, with the worst incident resulting in over 10 hours of interruption on average per customer. Even though the frequency of these events is low, the impact can be long duration outages for all customers on the feeder. Toronto Hydro plans to replace 20 of these switchgear over 2025-2029 to mitigate these risks.

E6.3.4 Expenditure Plan

To address the needs of the underground assets in downtown Toronto, Toronto Hydro plans to invest $165.1 million over the 2025-2029 period. Each segment entails a unique investment strategy as discussed in the following subsections.

Table 5: Forecast Program Costs ($ Millions)[16]

Segments	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Underground Cable Renewal	3.1	5.2	10.2	10.7	7.8	8.6	10.8	11.7	13.4	16.5
Cable Chamber Renewal	4.0	2.9	9.4	18.3	5.4	10.4	13.6	19.1	26.3	27.1
URD Renewal	-	0.4	0.6	0.4	2.1	1.0	1.0	0.9	1.0	0.8
Underground Switchgear Renewal	-	-	-	-	0.1	0.5	0.6	0.6	0.6	0.7
Total	**7.1**	**8.5**	**20.2**	**29.4**	**15.3**	**20.5**	**26.0**	**32.3**	**41.3**	**45.0**

[16] Note that costs associated with former streetlighting assets are embedded in the costs of the segments.

E6.3.4.1 Underground Cable Renewal Expenditure Plan

Over the 2020-2024 period, Toronto Hydro forecasts total spending of $36.9 million in the Underground Cable Renewal segment as shown is Table 6, which is approximately $52.8 million lower than planned in the 2020-2024 DSP. Over the 2025-2029 period, Toronto Hydro plans to spend $61.0 million to replace legacy PILC and AILC cable, an increase of 65 percent over the 2020-2024 period.

Table 6: Underground Cable Renewal 2020-2029 Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Underground Cable Renewal	3.1	5.2	10.2	10.7	7.8	8.6	10.8	11.7	13.4	16.5

Over 2020-2022, Toronto Hydro spent $18.5 million and installed 14 circuit-km of primary TRXLPE cable in duct and approximately 6 circuit-km of secondary cable in duct, as shown in Table 7. Toronto Hydro plans to invest another $18.4 million in 2023-2024 to install 16 circuit-km of primary TRXLPE cable in duct and 1.4 circuit-km of secondary XLPE cable in duct. The expected total PILC cable replacement for the 2020-2024 period exceeds the 2020-2024 DSP planned volume of 27 circuit-km by 3 km, while the expected AILC cable replacement is 44 circuit-km less than the planned volume of 53 circuit-km.

The variance in AILC cable is attributed to the prioritization of PILC over AILC cable replacement and a lack of colocation between the two. Toronto Hydro plans projects according to the priority of primary PILC feeder cables and any AILC cable along the route are identified for replacement at the same time for efficiency. This segment was a new segment for the 2020-2024 period and as project areas were selected, the utility discovered that there was lower than expected colocation between AILC cable and high priority primary PILC cables. AILC cable is mainly present in the secondary network system and some segments of AILC cable are being replaced through the Network System Renewal program.[17] Toronto Hydro has adjusted the forecast AILC volume for 2025-2029 based on this experience it has gained over the 2020-2024 period.

[17] See Exhibit 2B, Section E6.4.

The total expected 2020-2024 spending for this segment of $36.9 million is less than half of the $89.7 million forecast in the 2020-2024 DSP. Toronto Hydro reduced the segment budget significantly to support meeting the utility's capital funding limits,[18] but was still able to meet and slightly exceed the planned PILC cable replacement volume. The unit cost for PILC cable replacement over 2020-2022 was lower than the estimated unit cost in the 2020-2024 DSP due to the following:

- Civil work is costly and challenging to execute due to congested underground infrastructure, the City of Toronto's own infrastructure renewal plans, and other development projects. Therefore, as projects are developed from high level scoping to project development to detailed design, Toronto Hydro evaluates alternate options such as utilizing available civil infrastructure on the other side of the road or another parallel road to defer costly civil work and ensure the executability of projects. Over 2020-2022, Toronto Hydro successfully leveraged these alternatives to limit the amount of civil work needed and keep the average unit costs below the original estimates from the 2020-2024 DSP.
- Projects requiring more civil work require longer lead-up time due to additional design and permitting requirements. Since this was a new segment in 2020, the majority of the projects that the utility has been able to execute so far have not had significant civil work as they could move more quickly to the execution stage. Therefore, the historical unit costs for from 2020-2022 are not expected to be fully representative of future costs as they include mostly electrical costs only. As more projects are executed in future years, the average unit cost is expected to be closer to the estimated unit cost in the 2020-2024 DSP.

Toronto Hydro plans to invest $61 million in 2025-2029 to replace 35 circuit-km of primary PILC cable in duct, 9.3 circuit-km of secondary AILC cable in duct and 5 kilometers of fiber optic cable.

Table 7: 2020-2029 Volumes (Actual/Bridge/Forecast) – Underground Cable Renewal

Asset Class	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PILC Cable (km)	0.8	2.9	10.4	12.4	3.8	5.2	6.4	6.8	7.5	9.0
AILC Cable (km)	0.0	1.6	4.3	1.4	0.0	1.4	1.7	1.8	2.0	2.4
Fiber Optic Cable (km)	0.0	0.0	0.0	0.0	0.0	5.0[1]				

[18] See Exhibit 2B, Section E4 for more details.

Note 1: Toronto Hydro plans to install a total of 5 km of fiber optic cable units over the 5 year period and will determine the yearly allocation during project scoping based on infrastructure criticality and accessibility, feeder loading, and the feasibility of connecting to the existing fiber network.

The Underground System Renewal – Downtown program prioritizes at-risk cable segments based on historical failures, the number of splices on feeders, age, and customer base. Toronto Hydro will use this in conjunction with complementary cable testing data to validate the volume of cable replacement required. This is considered to be a best practice in the industry and is used by utilities such as Consolidated Edison (ConEd) in New York City for their PILC cable replacement program.[19] For cables where inspection and maintenance information is limited, studies have shown that this method is condition driven and a reliable alternative to traditional methods for asset ranking based on asset age, failure history, or asset 'health indices' .[20]

Toronto Hydro has determined that approximately 4.6 percent of the PILC population is in a critical state and should be addressed through proactive replacement during the 2025-2029 period. This 4.6 percent amounts to 44 circuit-km of PILC, and will trigger replacement of approximately 5.3 percent of the existing AILC population (9.3 circuit-km) connected downstream of PILC cable.

Toronto Hydro plans to install 5 km of fiber optic cables to enable on line cable monitoring in locations where no fiber optic cables currently exist. It should be noted that fiber optic cable network already exists on some sections of the downtown core and could be used to deploy online cable monitoring where applicable. Toronto Hydro will select locations to expand this fiber optic cable network based on the existing fiber optic network, the criticality of the route (e.g. number of feeders and key account customers served by the feeders), the difficulty in accessing or maintaining cables on those sections (e.g. rail crossings or under water tunnels), and colocation with a feeder identified for underground cable renewal work in the 2025-2029 plan.

Based on actual and forecast costs for 2020-2024 projects, Toronto Hydro estimates that PILC cable replacement projects will cost, on average, approximately $1.2 million per circuit-km, while AILC replacement will cost approximately $0.5 million per circuit-km. Toronto Hydro has applied these volumetric costs to the forecast population of critical cables to develop the 2025-2029 segment cost of $61 million.

[19] M. Olearczyk et. al., *Notes from Underground – Cable Fleet Management*, "online", http://www.neetrac.gatech.edu/publications/Note_from_Underground_Nov2010.pdf

[20] M. Buhari, V. Levi and S. K. E. Awadallah, "Modelling of Ageing Distribution Cable for Replacement Planning," in *IEEE Transactions on Power Systems*, vol. 31, no. 5, pp. 3996-4004, Sept. 2016.

E6.3.4.2 Cable Chamber Renewal Expenditure Plan

Over the 2020-2024 period, Toronto Hydro expects to invest a total of $40.1 million in the Cable Chamber Renewal segment as shown is Table 8 below, which is approximately $11 million higher than forecast in the 2020-2024 DSP. The higher spending is primarily due to a higher volume of lid replacement and higher than estimated unit costs.

Over 2025-2029, Toronto Hydro plans to increase spending in this segment to $96.5 million to address 199 cable chambers at risk of failure and 2,800 potentially hazardous cable chamber lids, as shown in Tables 8 and 9 below.

Table 8: Cable Chamber Renewal 2020-2029 Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Cable Chamber Renewal	4.0	2.9	9.4	18.3	5.4	10.4	13.6	19.1	26.3	27.1

Over the 2020-2022 period, Toronto Hydro spent $16.4 million to rebuild 10 cable chambers, complete 15 roof rebuilds, and replace 459 cable chamber lids with energy mitigation lids. Toronto Hydro plans to invest $23.7 million in 2023-2024 to replace 830 cable chamber lids, rebuild 22 roofs and 17 cable chambers, and complete 2 cable chamber abandonments. The total number of cable chambers addressed (excluding lids) is less than the proposed volumes in the 2020-2024 DSP as the average cost for cable chamber rebuilds, lid replacements and roof rebuilds has significantly increased compared to what was originally estimated in 2018.

When Toronto Hydro originally estimated the costs in this segment for 2020-2024, it had no actual costs or experience executing this work proactively to base its estimates on, as it was a new segment starting in 2020. Therefore, the estimates did not fully account for certain factors such as the need to replace obsolete PILC and AILC cables, the requirement to take outages to do full rebuilds in certain circumstances, and the full impact of working in congested areas downtow and requirements from the City that some of this work be performed only during weekends and at night. These factors were further exacerbated by the COVID-19 pandemic and unusually high escalation in labour and material costs over this period.

Table 9: Cable Chamber Planned Replacement Volume — Historical and Bridge Period

Asset Class	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Cable Chamber	4	1	5	9	8	3	4	9	15	15
Cable Chamber Roof	7	3	5	19	3	14	26	28	30	30
Cable Chamber Abandonment	0	0	0	1	1	3	5	5	6	6
Cable Chamber Lid	105	162	192	650	180	400	450	550	700	700

Toronto Hydro's spending plan for this segment for the 2025-2029 period includes the following breakdown:

- 2,800 cable chamber lid replacement (approximately $14,350 per unit)
- 46 cable chamber rebuilds (approximately $450,000 a unit)
- 128 cable chamber roof rebuilds (approximately $80,000 each unit)
- 25 cable chamber abandonments (approximately $25,000 each unit).

Toronto Hydro has applied these unit costs to planned unit volumes to develop the 2025-2029 segment cost of $96.5 million. Unit costs are based on recent experience planning and executing cable chamber renewal projects.

Reconstructing a cable chamber requires breaking into or reconstructing portions of duct bank. As such, the cable chamber renewal segment includes the cost of reconstructing a portion of a duct bank along with cable replacement within the cable chamber. Required electrical work within a cable chamber, road or sidewalk repair, and road restoration are also incorporated into the cost. In developing the cable chamber renewal segment costs for 2025-2029, Toronto Hydro now assumes that outages are not required for cable chamber roof rebuilds, but are required for full rebuilds of cable chamber when there are non-standard cables in the chamber which needs to be changed. If the cable chamber does not meet standard requirements, the civil structure will be rebuilt to meet current standards.

Based on inspection records, 592 cable chambers have been identified to be in HI4 and HI5 condition and another 521 are projected to become HI4 or HI5 by 2029 without investment. Toronto Hydro is increasing its investment in this segment to address 199 cable chambers and mitigate this increasing backlog and the associated safety and reliability risk. Cable chamber rebuilds are highly complex projects, as they require not only civil resources but also electrical resources, permits from the City to dig into streets, management of the high volume of downtown vehicular and pedestrian traffic, and extensive coordination between various stakeholders. The new chamber has to conform to current standards and the size may have to be enlarged to minimize congestion of the cables inside and to accommodate more cables for future needs. In light of these needs, a cable chamber rebuild requires a detailed design. The proposed pace is moderate and accounts for the above challenges and resourcing considerations, as well as the length of time civil deficiencies can be managed before renewal is required

Toronto Hydro mainly prioritizes cable chambers based on the condition of the civil infrastructure as well as the types of customers and thermal loading of feeders. As Toronto Hydro has gained experience planning and executing these projects and has a better understanding of the required costs, it expects to be able to ramp up the pace of investment over 2025-2029. Also based on recent project experience, when planning a cable chamber, the utility will also inspect adjacent chambers in the area and consider any intervention in tandem such that all required work can be completed together. Toronto Hydro will also review the location for possible challenges, such as interference with TTC or other utility infrastructure.

E6.3.4.3 URD Renewal

The URD Renewal segment aims to replace end-of-life and obsolete URD assets that contribute to the deterioration of system reliability. These assets include: vaults, switches, and transformers that form part of the URD system. In addition, THESL plans to install FCIs on select URD feeders that will be prioritized based on reliability performance in order to mitigate the risk of long duration outages.

Table 10 below provides the year over year breakdown of URD Renewal investment including the actuals (2020-2022), bridge (2023-2024), and forecast (2025-2029).

Table 10: URD Renewal 2025-2029 Segment Costs ($ Millions) — URD Renewal

Actual			Bridge		Forecast				
2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
-	0.4	0.6	0.4	2.1	1.0	1.0	0.9	1.0	0.8

The total (actual and bridge) 2020-2024 expenditure of $3.5 million is slightly higher than the 2020-2024 DSP forecast of $3.3 million. Over the 2020-2022 period, Toronto Hydro spent approximately

$1 million and completed three roofs rebuilds and replaced two submersible switches and one URD transformer. Toronto Hydro plans to spend approximately $2.6 million over 2023-2024 to renew seven submersible switches, five transformers, and seven vault roofs.

Table 11: URD Assets Planned Replacement Volume — Historical and Bridge Period

Asset Class	Actual			Bridge		Total
	2020	2021	2022	2023	2024	
URD Submersible Switches	0	0	2	1	6	9
URD Transformers	0	0	1	0	5	6
URD Vault Roof	0	1	2	1	6	10

Toronto Hydro spent slightly more than planned, while completing fewer roof rebuilds and switch replacements (but additional transformer replacements) due to the following reasons:

- Installation of new 200A switch was a pilot initiative, which also required a new vault roof design. As such, there was a significant learning curve in completing designs and obtaining approvals. Pilot projects related to new technologies are susceptible to risk due to uncertainties. The COVID-19 pandemic added another layer of complexity, for example increasing the lead time of the new 200A submersible switches, which affected project execution and timing.
- The unit cost of URD assets was higher than the originally estimated cost, which were estimated using comparable standards as Toronto Hydro had no previous experience with this work and the actual standards had yet to be developed at the time. This was further exacerbated by externally-driven escalations of labour and material costs over the 2020-2022 period. The higher units costs contributed to fewer units completed in order to limit overspending.

Toronto Hydro plans to invest $4.8 million over 2025-2029 to support maintaining URD system reliability and long-term asset risk levels. With this level of funding, the utility estimates that it can renew four submersible switches, 17 transformers, and four vault roofs, and replace 375 old and obsolete FCIs with the latest standard, as shown in Table 12. However, the number and mix of assets addressed are subject to change as Toronto Hydro prioritizes projects and develops detailed scopes. For example, the utility will prioritize projects based on the condition of civil roofs, as deficient roofs pose an immediate risk to the public and employees. Assets such as URD switches and transformers within these vaults will be replaced on an as-needed basis according to the latest available inspection records.

Table 12: URD Renewal 2025-2029 Volume Forecast

Asset Class	2025	2026	2027	2028	2029	Total
URD Submersible Switches	1	1	1	1	0	**4**
URD Transformers	3	3	3	3	5	**17**
URD Vaults (Roof Rebuild)	2	1	1	0	0	**4**
FCIs	0	100	100	100	75	**375**

E6.3.4.4 Underground Switchgear Renewal Expenditure Plan

The underground switchgear renewal segment aims to replace end-of-life and obsolete underground switchgear assets that contribute to the deterioration of system reliability and pose safety risks. Table 13 below provides Toronto Hydro's annual forecast 2025-2029 expenditures to address the critical underlying issues of the underground switchgear assets in Toronto downtown.

Table 13: Underground Switchgear Renewal 2020-2029 Segment Costs ($ Millions)

	Actual		Bridge			Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Legacy Switchgear	-	-	-	-	0.1	0.5	0.6	0.6	0.6	0.7

There are no historical expenditures associated with this program. Toronto Hydro plans to spend $0.1 million in 2024 for design work related to projects to be executed starting in 2025. Over 2025-2029, the utility proposes investing $2.9 million to replace four switchgears per year. The forecast costs are based on bottom-up estimates (i.e. labour and material requirements) to install a compact radial design standard, which is used in new building vaults.

Switchgear replacement projects may also include replacing transformers depending on the condition of the existing transformer and the feasibility of connecting it to the new standard switchgear. The planned pacing is the practical rate that Toronto Hydro is realistically able to achieve given available resources, while benefiting customers through reduced interruptions and safety risks. The utility will prioritize switchgear based on the condition (current and future HI), inspection and maintenance history, and historical reliability.

Table 14: Underground Switchgear Renewal 2025-2029 Volume Forecast

Asset Class	2025	2026	2027	2028	2029	Total
Underground Switches	4	4	4	4	4	**20**

E6.3.5 Options Analysis

E6.3.5.1 Underground Cable Renewal

1. Option 1: Reduced Pace

Under this option, Toronto Hydro would replace 3.2 percent of PILC cable (31.7 circuit km of 985 km) and 1.7 percent of AILC cable (3 km of 176 km) cables. This reduced pace is aligned with a 35-year timeline for removal of all remaining PILC and AILC cable (when considering cable replacement work done in other programs).

As mentioned in section 3.1, PILC and AILC cables are becoming obsolete across the industry due to environmental, health, and safety concerns. The longer it takes to remove these legacy cables from the distribution system, the greater the risk that Toronto Hydro will not be able to properly maintain the remaining population due to a lack of manufacturer support. In addition, approximately 58 percent of all PILC cables and 93 percent of all AILC cables in the system are more than 30 years old and these aged cables are showing signs of deterioration. Cable splices as a result of reactive replacement of failed PILC and AILC cable, which also increase failure risk, will also increase if these cables are not proactively replaced. This will negatively impact reliability for customers in the downtown area and drive up reactive spending.

Under this option, Toronto Hydro would also not invest in any installation of fiber optic cable, limiting the implementation of on line cable monitoring in the downtown area and the associated benefits described in section E6.3.3.1.

2. Option 2 (Selected Option): Sustainment pacing of PILC and AILC Cables

Under this option, Toronto Hydro is planning to remove approximately 3.5 percent of PILC cable (34.9 circuit kilometres of 985 kilometres) and 5 percent of AILC cable (9.3 circuit kilometres of 176 kilometres) and install 5 km of fiber optic cable over 2025-2029. This option will replace PILC cable at a pace aligned with a 30-year timeline to remove all PILC cable when considering the cable replacement work done in other programs.

Under this option, Toronto Hydro would mitigate the failure risk on the downtown distribution system and maintain reliability. As mentioned above, non-uniformity (i.e. cable splicing) increases the risk of failure. Therefore, by replacing the highest risk cables, the utility will increase the uniformity of cable types in the system (i.e. by replacing the non-uniform cable with XLPE cable), which will help maintain reliability on the system. The installation of fiber optic cable would enable Toronto Hydro to extend the reliability and asset optimization benefits from online cable monitoring.

In addition to maintaining reliability, this option will reduce the risk of oil leakage from the insulation on PILC cables and therefore reduce the need for service interruptions on customers to address these leaks.

3. Option 3: Accelerated Replacement of all PILC and AILC cable over 25 years

Under this option, Toronto Hydro would replace PILC and AILC cables in its distribution system at a pace aligned with a 25-year timeline for full removal when considering the cable replacement work done in other programs.

This would allow the utility to more proactively address the environmental and safety issues associated with the continued use of PILC and AILC cables. It would also mitigate the risks associated with a single supplier (i.e. procurement risk). Furthermore, it would address reliability risks and provide downtown customers with improved reliability.

However, this option is estimated to cost approximately 1.5 times the cost of the proposed plan and does not represent a reasonable balance between price and other outcomes such as reliability. It would also require that additional resources be allocated to this segment, which may be a challenge given other priorities.

E6.3.5.2 Cable Chamber Renewal

1. Option 1: Reduced Pace (Lid Replacements)

Under this option, Toronto Hydro would proactively address 199 cable chambers that represent approximately 35 percent of the projected HI4 and HI5 population by 2029 (without investment), which is consistent with Option 2. Toronto Hydro considers this to be the lowest reasonable number of cable chambers that should be addressed over 2025-2029 to address safety and reliability risks. It is also a pace that realistically accounts for the challenges in planning and executing this work and the required resources.

However, under this option Toronto Hydro would only replace 1,400 chamber lids at risk of ejection (approximately 12 percent of the population) with energy mitigation lids. Toronto Hydro finds that the safety risk due to the significant number of potentially hazardous cable chamber lids that would remain in the system is too high and therefore this option is not recommended.

2. Option 2 (Selected Option): Sustainment Pace

Similar to Option 1, under this option Toronto Hydro plans to proactively address 199 cable chambers that represents approximately 35 percent of projected HI4 and HI5 population by 2029 (without investment). The utility considers this to be the minimum number of cable chambers that should be addressed to sustainably manage the asset population and mitigate the growing backlog of deteriorated structures and associated safety and reliability risk. The proposed pace is moderate and accounts for the challenges and resourcing considerations associated with this work as well as the length of time civil deficiencies can be managed before renewal is required.

However, compared to Option 1, the proposed plan also includes the replacement of twice as many (2,800) potentially hazardous cable chamber lids (approximately 25 percent of the population) with energy mitigation lids. This would address all of the high risk locations and most of those considered a medium risk for lid ejection, mitigating the safety risk to a much more acceptable level.

3. Option 3: Accelerated Pace

Under this option, Toronto Hydro would address all at-risk (i.e. HI4/HI5) cable chambers and replace 5,000 cable chamber lids with energy mitigating lids. Although, this would significantly reduce safety and reliability risks associated with deteriorated cable chambers, this pace would require significantly more spending and resources and could pose execution challenges. Road moratoriums within Toronto's downtown core may further challenge Toronto Hydro's ability to execute the work at an accelerated pace in the short- to medium-term. Toronto Hydro finds that this is not an appropriate balance of benefits and costs and would potentially be infeasible to execute and therefore this option is not recommended.

E6.3.5.3 URD Renewal

1. Option 1: Reduced Pace

Under this option, Toronto Hydro would address select deteriorating URD assets at a reduced pace to manage deterioration. The investments would target the following:

- Replace approximately 25 percent of URD switches and 15 percent of URD transformers projected to be HI4/HI5 by 2029 (without investment);
- Rebuild vault roofs on approximately 25 percent of URD vaults projected to be HI4/HI5 by 2029 (without investment); and
- Install 150 FCIs on the URD feeders with the most outages.

Although this option would be cheaper and mitigate asset failure risk to some extent, it could still negatively impact URD reliability performance and increase safety [and environmental] risk and the deterioration of asset health. Reactive replacement and rebuild of URD assets would likely increase. Deteriorated civil condition of URD vault roofs can potentially compromise the electrical equipment within the vault and also increase the safety risk for Toronto Hydro employees when they enter the vault. Failing or deteriorated switches and transformers can release harmful environmental contaminants such as oil and SF6 gas and pose safety risks, in addition to impacting reliability performance. Finally, faulty FCIs can lead to prolonged outages, which customers have indicated a are a priority.

2. Option 2: (Selected Option) Sustainment Pace

Under this option, Toronto Hydro plans to proactively rebuild URD vault roofs and replace deteriorating and obsolete submersible switches and poor condition transformer at a modest pace. The investments would target the following (subject to detailed prioritization and planning of projects):

- Replace approximately 50 percent of URD switches and 40 percent of URD transformers projected to be HI4/HI5 by 2029 (without investment);
- Rebuild vault roofs on approximately 30 percent of URD vaults projected to be HI4/HI5 by 2029 (without investment); and
- Install 375 FCIs on the URD feeders with the most outages.

As URD vaults, transformers, and switches deteriorate, they need to be addressed proactively to reduce failure risk and mitigate the associated. Under this option, Toronto Hydro would invest a moderate incremental amount over Option 1 that better supports maintaining the reliability, environmental, and safety risks and longer-term sustainability of the URD system. This option is recommended because it provides the best balance between risk and cost compared to the other options.

3. Option 3: Accelerated Replacement of URD Assets

Under this option, Toronto Hydro would replace a larger population of the obsolete 200A switches and install FCIs across all URD feeders. Toronto Hydro anticipates that while this pacing option would better address reliability risk in the URD system, this strategy would also require significantly higher spending and does not represent an appropriate balance of price and reliability aligned with customer priorities. Therefore, this option is not recommended.

E6.3.5.4 Underground Switchgear Renewal

1. Option 1: Reactive Replacement Approach

This option entails continuing to operate the legacy underground switchgear units as is and replacing them only reactively upon failure. Failure rates have slowly increased in recent years and would likely continue to increase, which poses a challenge as there is no longer manufacturer support and spare parts are not available. Accordingly, maintaining the status quo will negatively affect system reliability and will pose potential safety risks to customers as well as Toronto Hydro personnel. As such, this option is not recommended.

2. Option 2 (Selected Option): Replacement of Underground Switchgear at Proposed Pace

Toronto Hydro's plan addresses safety risks associated with deteriorating legacy switchgear units and would improve reliability and safety of the system. The utility expects the replacement of legacy switchgear units to avoid some of the customer impacts and costs associated with in-service asset failures, such as customer interruptions and emergency repairs and replacement. At the proposed pace of 4 units per year, 20 of the 89 units forecast to have at least material deterioration by 2029 would be replaced and their associated safety and reliability risks addressed. Those remaining units not replaced by 2029 or ones not replaced in a timely manner will continue to pose a higher risk of failure until they are replaced. However, this is the recommended option as it is expected to result in an acceptable, but not ideal, reduction in the number of at-risk units at a reasonable level of spending.

3. Option 2: Replacement of Underground Switchgear at Accelerated Pace

Under this option Toronto Hydro would replace legacy switchgear units at an accelerated rate of 8 units per year to achieve faster reduction of safety and reliability risks associated with deteriorating legacy switchgear units. At this pace, Toronto Hydro would replace almost half of the 85 units projected to have at least material deterioration by 2029. This would reduce the number of legacy switchgear units operating at elevated risk of failure, however, it would also cost twice as much as Option 2 and is therefore not the recommended option.

E6.3.6 Execution Risks & Mitigation

A key execution risk affecting the Underground System Renewal – Downtown program is external dependencies. In the downtown area, coordination with third parties (e.g. City of Toronto, TTC) has been an on-going requirement. Toronto Hydro invests substantial efforts to ensure effective inter-agency coordination.

Toronto Hydro ensures that optimal routes are chosen based on criteria, such as the avoidance of busy intersections and paths where utilities reside. Often, projects require construction of new civil assets such as duct banks or cable chambers. It is expected that these projects may be delayed without effective coordination. To mitigate risks, these projects will be planned well in advance.

Additionally, road moratoriums have the potential to delay projects in the downtown core. To mitigate this risk, Toronto Hydro will plan and schedule work accordingly.

Underground Cable Renewal will prioritize at-risk cables dynamically as testing data, and cable replacement data become available. This means cables that are deemed low-risk one year, may be high risk in another year. As such, dynamic planning will be required, targeting the highest risk assets based on the best available information, i.e. feeders that are statistically more likely to fail. However, this approach may result in disruptions to project scheduling and planning. Efforts will be made well in advance to coordinate multiple projects at the same time so projects are deferred or advanced accordingly.

The successful roll out of new URD assets, including URD submersible switches will depend on the results of a field trial that is currently underway. The plan is to incorporate lesson learned and make any changes before standardizing the product. In addition, since all URD assets are located in residential neighbourhoods in the downtown core, coordination with the relevant customers is critical. Toronto Hydro will abide by residential community by-laws such as noise levels placed by the City of Toronto and coordinate with all stakeholders as necessary.

There may be unforeseen conditions or access problems with some customer-owned civil structures. In these situations, the customer may have to perform civil rebuild work before Toronto Hydro's work can commence, thereby causing project delays. This risk can be mitigated by fully inspecting all civil plant prior to finalizing project design, and introducing sufficient lead times for customer civil design and construction activities in the project schedule.

Finally, as has become evident over recent years, supply chain pressures and disruptions can drive up material costs and impact timelines. This is mitigated through proactive internal engagement and coordination and Toronto Hydro's procurement strategy. For more details on what Toronto Hydro has been doing to address this issue please see Exhibit 4, Tab 2, Schedule 15 (Supply Chain).

E6.4 Network System Renewal

E6.4.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 116.1	**2025-2029 Cost ($M):** 123.4
Segments: Network Unit Renewal; Network Vault Renewal; Network Circuit Reconfiguration	
Trigger Driver: Failure Risk	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Environment, Financial Performance	

The Network System Renewal program (the "Program") addresses deteriorating and functionally obsolete underground network system assets serving primarily small to medium-sized customers in the pre-amalgamation City of Toronto. These customers reside in the City's core and are often sensitive to outages.[1] For example, sensitive customers that are served by this part of the system include commercial businesses, GO Transit, and hospitals. The Program is designed to maintain reliability and mitigate public safety risks by: (1) replacing non-submersible and deteriorated network units, (2) replacing network vaults in deteriorated condition, and (3) reconfiguring and re-cabling sub-optimal grid networks.

The Program is grouped into the three (3) segments summarized below and is a continuation of the network renewal activities described in Toronto Hydro's 2020-2024 Distribution System Plan, with the exception of Legacy Network Equipment Renewal which was completed in the current rate period.[2]

- **Network Unit Renewal:** This is a continuation of planned replacement of network units at risk of failure. As network unit condition deteriorates, the risk of failure increases, and with it the likelihood of consequences such as lengthy customer outages and vault fires. This segment will target deteriorated units, predominantly non-submersible units. The non-submersible units are susceptible to water ingress and elevated failure risks even when in

[1] As discussed in Exhibit 2B Section D2.2.2, the underground network system is the most reliable configuration available among Toronto Hydro's distribution schemes, and is therefore an ideal option for customers who are sensitive to outages and concerned about reliability.

[2] EB-2018-0165, Exhibit 2B, Section E6.4. Over 2020-2024 Toronto Hydro successfully completed the Legacy Network Equipment Renewal segment by replacing all of the remaining Automatic Transfer Switches ("ATS") and Reverse Power Breakers ("RPB").

good condition. Toronto Hydro will prioritize the replacement of high failure risk units as indicated by condition inspections and health index scores. Without intervention, the utility projects that 149 units will be materially deteriorated ("HI4") or at end-of-serviceable life ("HI5") by 2029 and that 50 percent of its network units will be at or beyond useful life by 2034. The utility plans to replace 130 network units between 2025 and 2029. This rate of replacement is expected to reduce failure risk on the network system by improving condition-related asset risk across the network unit population. Toronto Hydro plans to install new network units that are submersible and equipped with sensors to monitor transformer, protector, and vault conditions, resulting in the cost-effective reduction of reliability, environmental, and safety risks associated with network assets.

- **Network Vault Renewal:** This is a continuation of Toronto Hydro's efforts to rebuild or decommission poor condition network vaults. These civil structures were generally built in the 1950s and 1960s, mainly beneath the sidewalks in the busy downtown core. Toronto Hydro must proactively address structurally deficient vaults in order to mitigate risks to public safety, employee safety, and system reliability, and to maintain the long-term viability of the distribution system. If the proposed work is not completed, the number of network vaults in HI4/HI5 condition is forecasted to increase from 91 to 137, or approximately 29 percent of the vault population, by 2029. During the 2025-2029 period, Toronto Hydro plans to eliminate immediate structural deficiencies of 38 high-risk vaults identified through the Asset Condition Assessment ("ACA") process as having at least material deterioration ("HI4"). Due to the complexity of this mostly downtown work, the rate of planned replacement is less than optimal. However, at the pace of renewal, Toronto Hydro will see a slight increase in the assets in material deterioration or end-of-serviceable-life (HI4 or HI5 condition by the end of 2029, relative to 2022.

- **Network Circuit Reconfiguration:** This is a continuation of Toronto Hydro's plan to mitigate the impact of multiple contingency failures on the network system. This segment involves reconfiguring and re-cabling secondary grid networks into more robust spot vaults and enhanced grids. The result will be minimized customer interruptions, improved planning, modeling, and operational flexibility, and enhanced ability of the network system to operate under extreme events (e.g. multiple contingency outages). Toronto Hydro plans to reconfigure the parts of three secondary networks over the 2025-2029 rate period, an investment that is expected to deliver long-term reliability and resiliency benefits for network customers in the downtown area.

Toronto Hydro plans to invest $123.4 million in the Network System Renewal program over the 2025-2029 rate period, which is approximately a 6 percent increase over projected 2020-2024 spending on this Program (including forecasted inflation). This level of investment is necessary to maintain public and Toronto Hydro employee safety, and the service levels that downtown customers rely on and expect from the network system.

E6.4.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's Network Units Modernization measure and system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Replacing 130 network units at highest risk of failure due to poor condition or vulnerability to flooding; ○ Eliminating structural deficiencies of 38 high-risk vaults that are placing enclosed equipment at risk; ○ Replacing older non-submersible or submersible network units with those equipped with sensors to monitor vault conditions and enable quicker response to adverse network conditions; ○ Reducing average restoration time during a full network outage by reconfiguring networks to support all or most of the load; ○ Reducing customer interruptions by a third during second contingency events, by reconfiguring networks to improve operability under multiple contingency events.
Environment	• Contributes to Toronto Hydro's environmental objectives by eliminating network units at high risk of failure and vulnerable to vault fires or oil spills.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's modernization and safety objectives by: ○ Minimizing the risk of catastrophic transformer failures by replacing network units most at risk due to deteriorated condition or exposure to higher-risk environmental factors; ○ Eliminating potential trip and falling debris hazards at 38 vaults with significant civil deterioration.

Financial Performance	• Contributes to Toronto Hydro's financial objectives by: ○ Reducing the need to dispatch crews in multiple contingency scenarios by reconfiguring the network to support all or most of the network load; and ○ Supporting reduction in summer peak reading inspections by enabling monitoring and control of network units (see Network Condition Monitoring and Control program).[3]

E6.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Safety, Environmental Risk, Reliability, System Efficiency

Toronto Hydro's network system plays an important strategic role in meeting the reliability expectations of interruption-sensitive downtown customers. The Network System Renewal program aims to replace network assets at risk of failure due to deteriorating conditions. The failure of these assets negatively impacts reliability and the effective operation of the network system and potentially increases the risk to public safety and Toronto Hydro's crews.

Toronto Hydro's low voltage secondary network distribution system includes the following assets:

- Network Units that consist of primary switches, network transformers, and secondary network protectors, which are assembled into a single unit;
- Network Vaults, which contain the aforementioned equipment; and
- Secondary Cables, which connect the aforementioned equipment and provide service connections to customers.

The Network System Renewal program is needed to replace those assets that are at risk of failure in order to mitigate the associated safety, environmental, and reliability risks and to maintain the service levels that downtown customers rely on and expect from the network system.

[3] Exhibit 2B, Section E7.3

E6.4.3.1 Network Unit Renewal

The Network Unit Renewal segment is a continuation of the activities identified in Toronto Hydro's 2020-2024 rate application. This segment aims to reduce failure risks associated with network units that are obsolete, in poor condition, and prone to failure. The goal of the segment is to replace the most at-risk units, as indicated by the above criteria, before they fail and potentially cause safety or environmental incidents such as fires or oil leaks.

Although replacements are prioritized based on condition, the network units that are replaced are typically legacy "non-submersible" designs characterized by "ventilated" (see Figure 1) or "semi-dust-tight" protectors. These units are susceptible to water ingress and elevated failure risks even when in good condition. These units also typically contain electro-mechanical relays that are not capable of remote condition monitoring or control. They are replaced with units that are of a submersible design (see Figure 1), containing microprocessor relays, and are capable of meeting the requirements for Toronto Hydro's Network Condition Monitoring and Control program.

Figure 1: Snapshot of a Ventilated Network Unit (L) and Submersible Network Unit (R). The black protector is of a submersible design, which prevents water ingress.

1. Failure Risk and System Efficiency

Two main failure modes can impact a network unit. The first is flooding of the network vault that may damage the protector mechanism causing the unit to short, or fail to operate. The second is an internal transformer failure that is typically caused by low oil, moisture ingress, or age-related insulation deterioration. To maintain network system reliability, network units need to be both routinely maintained and proactively replaced when they are at an increased risk of failing. Maintenance of network units is summarized in Exhibit 4, Tab 2, Schedule 2. Not replacing deteriorated network units in a timely manner can lead to equipment failures, and in turn cause interruptions to customers, oil leaks of 1,000 litres and more, and potential vault fires that may impact (including by expelling smoke) busy arterial roads in the downtown core of Toronto.

Replacing deteriorated or non-submersible units located in areas prone to flooding with submersible protectors that feature watertight cases can help address failure risks. Toronto Hydro will prioritize the replacement of high failure risk units as indicated by condition inspections and health index information. Toronto Hydro has over 1,900 network units of which roughly 30 percent have non-submersible protectors, which are legacy designs used prior to the installation of the first submersible units in 2003. As a result, virtually all units older than 20 years are ventilated or semi-dust-tight.

Figure 2 shows the current age distribution of submersible and non-submersible network units. With a useful life 35 years, as of the end of 2022, approximately 22 percent of the network unit population is at or beyond useful life. Without any capital investment, this number is projected to increase to 27 percent by 2029 and to 56 percent by the end of 2034. Not investing at a steady pace of asset renewal will not only increase reliability risks on the distribution system but also increase the need to ramp investments in the future and associated complexity involved in replacing a large number of units over a short period. This could result in more outages and higher safety risks due to failure.

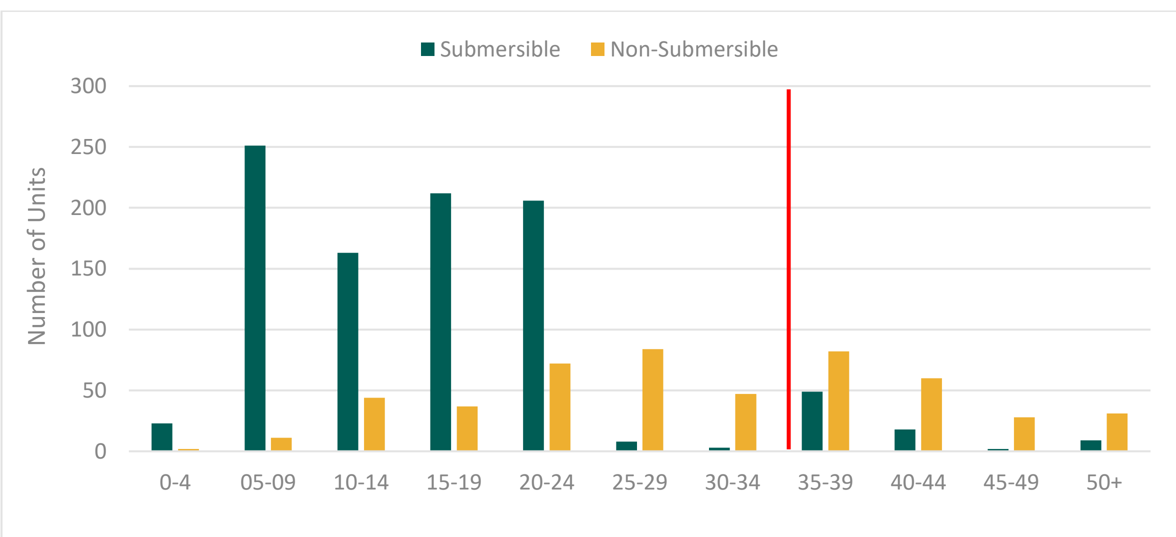


Figure 2: Network Unit Age Demographics

Based on 2022 ACA data, the current and estimated 2029 health index distribution (without proposed work) for network units is shown in Figure 3. HI4 means “material deterioration” and HI5 means “end of serviceable life”. It is expected that HI4/HI5 numbers will increase from 43 units (in 2022) to 149 units in 2029. The network unit renewal segment plans to replace 130 units at an average rate of about 26 per year over the 2025-2029 rate period to address deteriorating and high failure risk units.

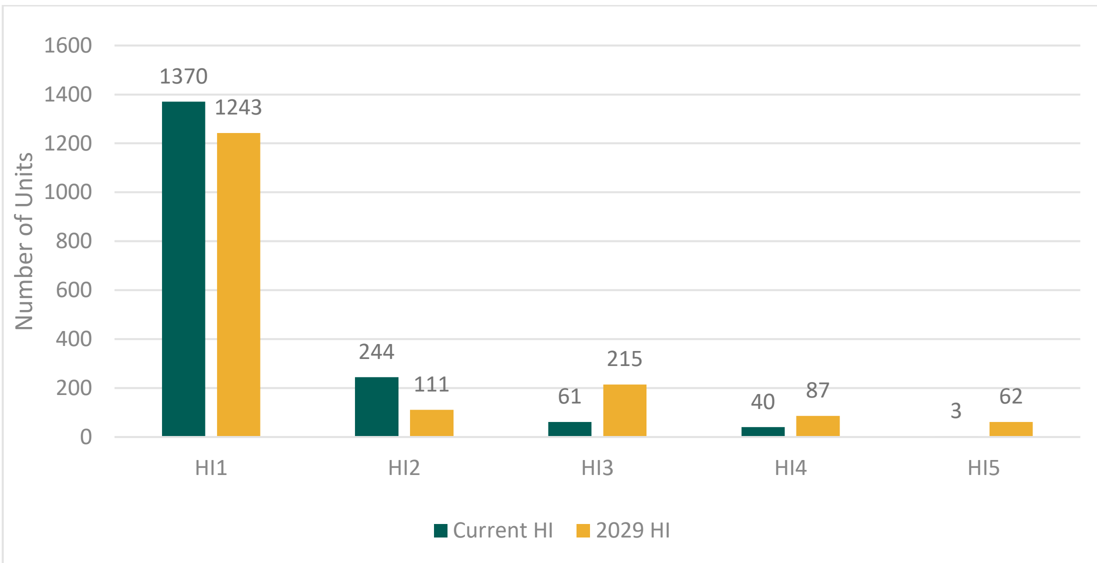


Figure 3: Network Transformers Condition Demographics – Current and Forecasted HI (without Renewal)

2. Safety and Environment

Failure of deteriorated network units can result in both safety and environmental incidents. From a safety perspective, catastrophic failures may cause damage to surrounding property and put the public at risk of injury, especially given that network vaults are typically installed under sidewalks with significant pedestrian traffic. From an environmental perspective, corroded and deteriorated network units may result in oil leaking within a vault, and the possibility of oil escaping through vault drainage systems into the environment. Between 2020 and 2022, Toronto Hydro has experienced 82 oil leaks from network transformers. As network transformers typically contain more than 1,000 litres of oil, oil leaks have the potential to lead to serious environmental consequences. Figure 4 shows the distribution of the 82 network transformer oil leaks experienced by volume of oil leaked.

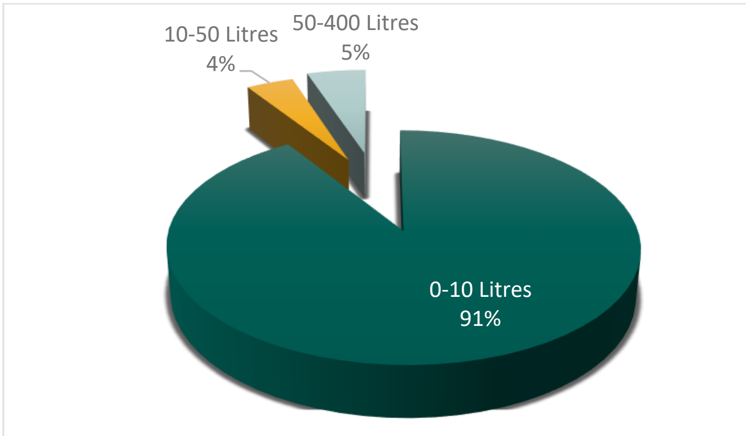


Figure 4: Network Transformer Oil Leaks (2020-2022)

Oil leaks are mitigated by replacing deteriorated units and units operating in environments which place them at elevated risk.

E6.4.3.2 Network Vault Renewal

The Network Vault Renewal segment is a continuation of the network vault rebuild and decommissioning activities detailed in Toronto Hydro's 2020-2024 rate application. Many network vaults associated with the secondary network system were constructed in the 1950s and 1960s, mainly beneath the sidewalks in Toronto's busy downtown core. Today, these assets have many critical structural issues and Toronto Hydro plans to address the worst of them based on condition data. The aim of this segment is to reduce failure risks resulting from vault structural deficiencies that can negatively impact the reliability and effective operation of the utility's distribution system as well as safety risks to the public and Toronto Hydro crews.

3. Failure Risk

Vault structural deficiencies are mainly caused by old age and exposure to adverse environmental factors. Currently, Toronto Hydro has about 470 network vaults, predominantly in the downtown core, supplying the network system. Figure 5 shows the age distribution of all network vaults with reference to the useful life of both the overall vault (60 years) and the roof (25 years).

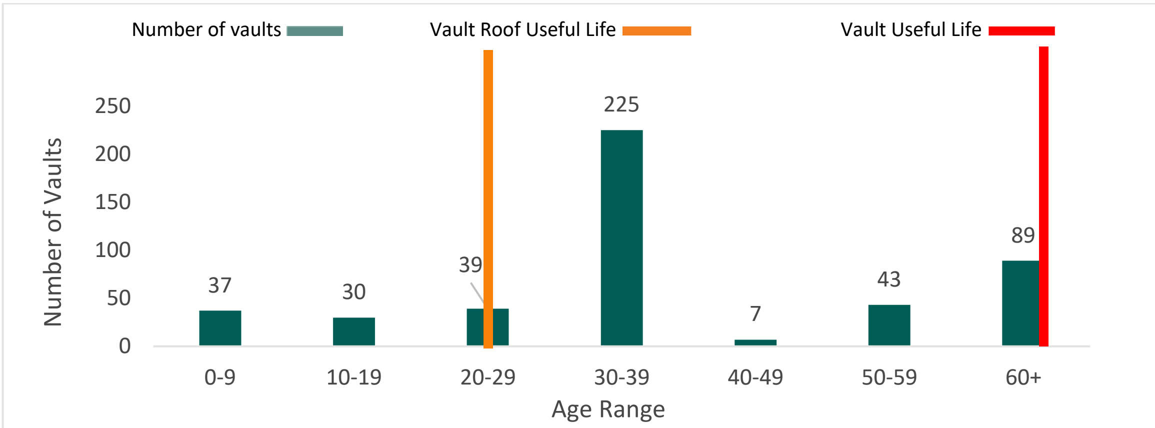


Figure 5: Age Distribution of Network Vaults

The vast majority of vault roofs have reached the end of their expected useful life of 25 years. Additionally, over 28 percent of the vault civil structures will reach the end of their expected useful lifespan (of 60 years) within 10 years. ACA results show that some vaults are deteriorating at an accelerated pace and require repairs even though they have yet to reach their expected lifespan. The increased use of de-icing salts in recent years is contributing to this accelerated aging. Figure 6 shows that as at the end of 2022, 91 (19 percent) of Toronto Hydro-owned network vaults exhibit at least material deterioration (HI4/HI5) and are clear candidates for work under this renewal segment. This number is forecasted to grow to 137 (29 percent) in 2029 if the proposed work is not completed. In addition to the 23 network vaults planned for renewal in 2023-2024, Toronto Hydro plans to address 38 network vaults between 2025 and 2029 to alleviate the risks posed by deteriorating vaults.

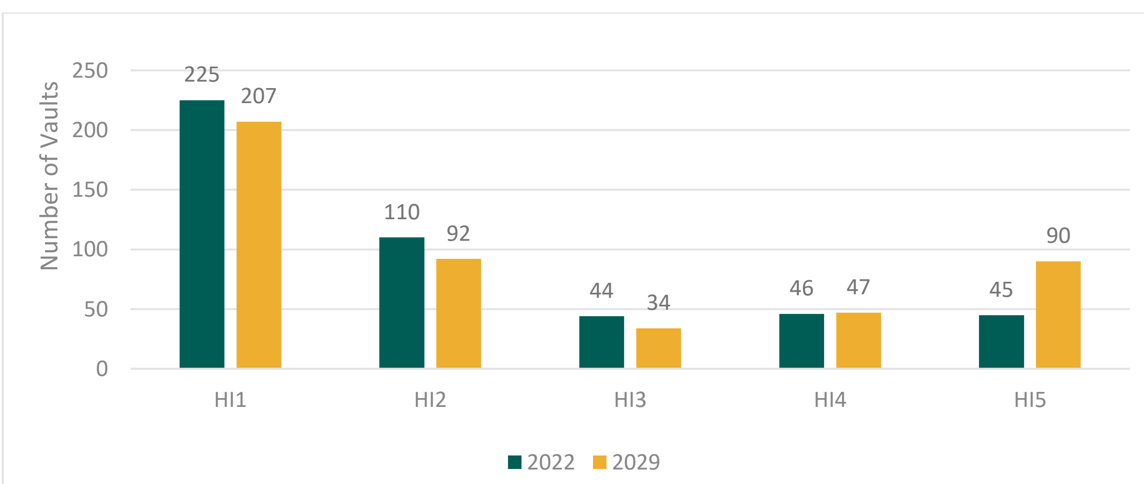


Figure 6: Current, 2025 and 2029 Health Scores for TH-owned Network Vaults

Some commonly found structural deficiencies caused by asset aging and environmental factors are described in Table 4.

Table 4: Vault Structural Deficiencies and Impacts

Deficiency	Impact
Exposed Roof Rebar	Failure risk that can lead to roof collapse, damage to equipment and safety hazard to the public and Toronto Hydro crews.
Exposed Wall Rebar	Failure risk may result in collapse of the vault walls, potentially leading to damaged equipment, costly repairs, safety hazards, and power outages.
Corroded I-Beams	Failure risk due to age and environmental factors can lead to collapse of the roof structure.
Cracked Roof	Exposes electrical equipment to leaking water and accelerated corrosion which may result in catastrophic failure.
Cracked Walls and Floor	Increases risk of failure causing flooding and damage to equipment which may result in large outage.

Examples of these deficiencies are shown in Figure 7, Figure 8, Figure 9, and Figure 10 below.

Figure 7: Roof and Wall with Exposed Rebar

Figure 8: Corroded I-beams

Figure 9: Cracked Roof and Wall

Figure 10: Deteriorated Vault Floor

4. Reliability and System Efficiency

As discussed above, there are several failure modes and deficiencies that may lead to structural failure within a vault. Such damage to the network vaults is likely to negatively affect the performance of the electrical equipment contained inside, potentially contributing to a catastrophic failure of the network assets within the vaults, thereby causing a power outage in the downtown core. Such a power outage could impact between 500 customers (5 MVA) for smaller network grids and up to 3,000 customers (50 MVA) for the large network grids in the downtown core. The outage can last from several hours to a few days, depending on the location, the severity of the fault and, the network distribution system being impacted.

If a vault roof is not replaced on time, removing it later to replace faulty equipment can cause it to collapse, making it more dangerous and challenging for the crew to replace the equipment. In this scenario, the feeder providing power supply to the failed equipment will be turned off for longer periods of time, which will increase the risk of an outage to the customers fed by that feeder. To maintain reliable service to interruption-sensitive downtown customers, it is imperative that these assets be renewed before they fail.

5. Safety

Table 5 highlights different safety risks to the public and Toronto Hydro crews resulting from deteriorated network vaults. There are two main types of risks to the public. First, the risks of slips, trips, and falls stem from cracking and structural shifting of vault roof structures. Second, complete failure of roof elements can expose the public to energized electrical equipment.

Table 5: Safety Risk & Descriptions

Safety Risk	Description
Slips, Trips & Falls	A deteriorated vault roof may result in uneven grading on sidewalks or walkways and lead to slips, trips, or falls, which could cause injury to members of the public or Toronto Hydro crews.
Falling Debris	Toronto Hydro crews working inside the vault may encounter falling debris from the deteriorated roof or walls of the vault. This could lead to serious injury, especially when working near live equipment.
Fire	Poor condition of vaults can be a contributing factor to catastrophic failures such as vault fires.

The risk posed by cracking and structural shifting can be controlled by a maintenance program that patches or grinds down hazardous structural elements as needed. However, once a vault reaches the point where major structural deficiencies cannot be addressed by maintenance, three different options are available:

- **Decommissioning vaults** (see Figure 11) that are no longer needed as a result of load displacement. The typical cost to decommission a vault is approximately $150,000 to $180,000 and it takes approximately one month to perform the work;
- **Rebuilding the vault roofs** (see Figure 12) where severe structural deficiencies have been identified, but which are located on network vaults that are otherwise structurally sound. The typical cost of rebuilding a vault roof is up to approximately $360,000 and it can take approximately three months to perform the work;
- **Rebuilding entire vaults** (see Figure 13) that have been identified as having severe structural deficiencies requiring a complete reconstruction. These vaults cannot be decommissioned but require more extensive repairs beyond a vault roof replacement. The typical cost for

rebuilding a vault is up to approximately $1.8 million, which includes the average costs for both civil and electrical work. This work can take between 18 and 24 months to complete.

Toronto Hydro also considers evolving customer needs and system requirements when choosing the best course of intervention for any given vault location.

Figure 11: In-Progress Vault Decommissioning

Figure 12: Temporary Roof during a Roof Rebuild

Figure 13: Completely Rebuilt Vault

For the 2025-2029 Network Vault Renewal segment, Toronto Hydro plans to address the immediate structural vault deficiencies of 38 high risk vaults identified through Toronto Hydro's ACA process as having at least material deterioration. In addition to the ACA process, Toronto Hydro carries out civil assessments wherein a civil engineer visually inspects the network vault roof and walls to recommend whether a roof or whole vault rebuild is required.

E6.4.3.3 Network Circuit Reconfiguration

Toronto Hydro plans to reconfigure large network grids so that either: (i) sufficient grid flexibility is introduced to enable the sustainment of second contingency events; or (ii) sufficient customer loads are automatically dropped during second contingency events to allow the remainder of the grids to continue operating reliably.

A reconfigured network should, by design, shed sufficient load under second contingency conditions to allow the remainder of the grid to continue to operate. The network grids targeted for reconfiguration between 2025 and 2029 have six feeders on average and an average of 30 MVA. This segment is a continuation of the work under the same program, as described in the 2020-2024 rate application. In a second contingency event, instead of losing all 30 MVA, the reconfigured networks would only lose about 10 MVA. This equates to a 67 percent reduction in interrupted load.

The Network Circuit Reconfiguration segment uses a number of different methods to address the problems and risks associated with multiple contingency events. The methods used depend on the configuration of the network and the requirements needed to reconfigure it into a robust system that supports second contingency. A single reconfiguration project may utilize multiple methods including:

- **Splitting grid into spot vaults:** This option solves overload problems under second contingency events that could result in equipment failure, and eliminates the need for power system controller intervention during these events.
- **Splitting grid into enhanced mini-grids:** This option is able to better sustain customer loads under multiple contingency events than what is possible using the first option. However, a third contingency would still result in a serious transformer overload and require prompt action by the power system controllers to identify the problem and shed load accordingly.
- **Upsizing transformers:** The option allows all customer loads to be sustained during any second contingency condition; however, a third contingency would still result in a serious transformer overload and would require prompt action by the power system controllers to identify the problem and shed load accordingly.
- **Changing primary feeder connections to network transformers:** This option improves diversity in the feeders supplying the network, thereby making it more resilient to multiple contingency events.

- **Reinforcing existing secondary network grid cabling:** This option ensures secondary cabling is not overloaded during multiple contingency events.

6. Failure Risk

Network Circuit Reconfiguration mitigates the impact of failures. The risk of network system outages has increased over time due to:

- **Evolving Operating Practices:** The secondary network system was originally designed to burn clear faults and self-isolate damaged equipment so that most failures of network transformers and primary and secondary cabling do not result in customer interruptions. However, a small number of transformer failures resulted in vault fires. The fire department's current practice is to require that Toronto Hydro immediately cut all power supplies into the vault as a first step in fighting the fire. As a consequence, multiple network primary feeders must be tripped, which may leave insufficient remaining contingency capacity to sustain the network grid.
- **Multiple Contingency Events:** Operation of the network system under multiple contingency scenarios imposes challenging requirements on operating personnel. First, a network expert must analyze the grid to identify critical overload conditions and propose customer load reductions and necessary reactive tasks, all within restrictive time limits. If an expert is not immediately available at the control center, power system controllers may be forced to drop the entire grid in order to prevent a network cascade failure. Second, once the necessary reactive switching and load reduction tasks are identified, system response crews must perform this work, and customers need to reduce their loads within the identified time limitations.
- **Reach of the Secondary Network Distribution System:** The secondary network distribution system represents approximately 10-15 percent of downtown Toronto's peak load. Although it is Toronto's most reliable distribution system, when a major secondary network equipment failure occurs, the impact is widespread, including many radial supply loads on the same feeders. Often major portions of station switchgear, with up to about 50 MVA of customer load (equivalent to approximately 25,000 residential customers), must be interrupted following such events.

For a typical network with no more than six primary feeders, a widespread forced outage due to a second contingency event would cause about 30 MVA of load to be dropped for four hours to prevent equipment overload. In recent years, these events have occurred approximately once every three years. A reconfigured network grid should be able to sustain a second contingency incident without requiring the entire network to be dropped. This should typically result in a two-thirds reduction in interrupted load.

7. Reliability and System Efficiency

The network system in Toronto was designed for first contingency operation. Under any first contingency event, power system controllers do not need to take any action to ensure continued reliable supply to network customers. On the other hand, multiple contingency events would require immediate action by power system controllers and system response crews. Often, only minutes are available to take effective action in order to prevent a network cascade failure. As previously mentioned, Network Circuit Reconfiguration enables a network to sustain a second contingency incident without requiring the entire network to be dropped. Since almost all network emergencies involve only first and second contingency outages, this will result in an efficiency improvement in terms of system control.

In addition, most multiple contingency network emergencies require the power system controllers and system response crews to spend hours conducting switching operations to stabilize the network and restore as many customers as possible. As a result, isolation and repair of failed equipment may be delayed until this work is completed. Network Circuit Reconfiguration is expected to reduce the workload required to stabilize the network and restore customers, allowing for restoration work to begin at the earliest opportunity, thereby minimizing the time required to restore the network to normal operation.

Table 6 below identifies the networks targeted for reconfiguration in the 2025-2029 rate period. Over 2025-2029, Toronto Hydro will complete reconfiguration for the parts of three networks that are carried over from the 2020-2024 and 2015-2019 rate periods. All networks targeted will be reconfigured after they have been updated with monitoring and control through the Network Condition Monitoring and Control program.[4] Through Network Condition Monitoring and Control alone, it is expected that around one-third of total network load will be preserved during second contingency events. A reconfigured network will typically preserve approximately two-thirds of the total load during these events (representing an additional one-third savings during second

[4] Exhibit 2B Section E7.3

contingency events on networks already updated with condition monitoring and control). The synergies between these two programs are expected to allow many customers to be sustained even during rare third contingency events.

Table 6: 2025-2029 Targeted Networks for Reconfiguration

Network	Network Feeders	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Reconfiguration Year
A-North Phase 2	9	22	15	2025
GD Phase 2	9	25	20	2026
CE-South South Ph2	8	16	7	2027

The networks to be reconfigured during this filing period represent around 10 percent of the major network system load. Multiple contingency events occur approximately once each year and the existing network system can successfully manage approximately two-thirds of these events.

8. Functional Obsolescence

The existing secondary grid network distribution system was initially designed for pure network loads and not the mixed network and radial loads that exist today. Network feeders are designed such that they can be highly loaded since loads are automatically redistributed across all other network feeders in case of an outage. However, because radial feeders cannot be loaded as highly, due to the need for them to pick up load during contingency scenarios affecting adjacent feeders, the overall utilization of a mixed feeder is reduced. Furthermore, because of the presence of radial loads on a mixed feeder, the capacity to operate the network under multiple contingencies becomes insufficient. Enhancement of secondary network grid flexibility is necessary to adapt to this new reality.

E6.4.4 Expenditure Plan

To address the critical underlying issues of the network assets in downtown Toronto, the utility plans to invest $123.4 million in the Network System Renewal program during the 2025-2029 rate period. Table 7 below provides Toronto Hydro's annual Historical Years (2020-2022), Bridge Years (2023-2024) and forecasted 2025-2029 expenditures for each of the Program segments.

Table 7: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Legacy Network Equipment Renewal (ATS & RPB) [5]	1.9	1.3	0.8	0.3	-	-	-	-	-	-
Network Unit Renewal	5.9	8.7	12.3	17.2	9.1	6.2	6.4	11.7	12.7	14.2
Network Vault Renewal	6.1	9.1	15.7	10.4	8.6	6.7	6.9	18.0	18.5	19.0
Network Circuit Reconfiguration	1.2	3.1	3.3	0.7	0.8	0.8	1.5	0.8	-	-
Total	**15.0**	**22.1**	**32.0**	**28.6**	**18.4**	**13.7**	**14.8**	**30.5**	**31.2**	**33.2**

E6.4.4.1 Network Unit Renewal

Table 8 below provides the year over year breakdown of Network Unit Renewal investment spending including the actual historical spending from 2020-2022, the bridge years from 2023-2024, and forecasts for 2025-2029.

Table 8: Historical and Proposed Investment Spending ($ Millions) — Network Unit Renewal

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Network Unit Renewal	5.9	8.7	12.3	17.2	9.1	6.2	6.4	11.7	12.7	14.2

Toronto Hydro invested $26.9 million in network unit renewal between 2020 and 2022, replacing 82 deteriorated and non-submersible units as shown in Table 9. An additional 84 network units were replaced reactively. The utility plans to invest a total of $53.2 million by the end of 2024 to proactively replace an additional 95 network units over 2023 and 2024 to minimize failure risks.

Table 9: Network Units Replaced — Actual/Bridge vs Planned

	Actual	Bridge	Total

[5] Over 2020-2024, Toronto Hydro successfully completed the Legacy Network Equipment Renewal segment by replacing all of the remaining ATSs and RPBs.

	2020	2021	2022	2023	2024	2020-2024
Actual / Planned	20	30	32	44	51	177

The higher segment cost, while completing fewer units was mainly driven by:

- Increased amount of legacy cable removal and upgrade work completed while changing out network units. Many of the targeted units are in vaults where Asbestos-Insultated Lead-Covered ("AILC") secondary cable containing asbestos and lead are present and/or have primary Paper-Insutated Lead-Covered ("PILC") cable that terminates at the network units. While the Underground System Renewal – Downtown targets the proactive replacement of AILC and PILC cables, Toronto Hydro replaces these legacy cables as part of network unit renewal projects to improve work execution efficiency. [6]
- Similarly, where appropriate, Toronto Hydro spent more than expected to install certain Network Condition Monitoring & Control ("NCMC") equipment and perform the necessary wiring while replacing network units to improve overall efficiency.
- Material cost increases driven by raw material price increases.
- Project execution challenges including constraints related to moratoriums, coordination issues between stakeholders, and scheduling feeder outages resulted in delay in work execution for some projects. In some instances, civil work was needed to be completed prior to unit renewals.

Over the 2025-2029 rate period, Toronto Hydro plans to spend a total of approximately $51.2 million on this segment to replace deteriorating and high failure risk units. The utility forecasts 149 network units will have at least material deterioration (HI4/HI5) by 2029 and that 27 percent of the total population is expected to be at or beyond useful life. Of these, Toronto Hydro plans to replace 130; an average rate of 26 units replaced per year between 2025 and 2029. While the pace of renewal over the DSP period is lower relative to 2020-2024 pacing, Toronto Hydro forecasts that the proposed pace of renewal is required to mitigate further increases in risk. In addition, THESL has incorporated the results of customer engagement to pace the Network Unit renewal investment.

[6] Exhibit 2B, Section E6.3.

The replacement of units with the highest failure risk is projected to maintain downtown reliability and reduce the safety and environmental risk associated with those units. In addition, newer units will be equipped with new features (e.g. monitoring capabilities to enable faster response to developing problems and submersible protectors).

To minimize costs and use resources efficiently, Network Unit Renewal projects will be combined with other Network System Renewal projects, where possible. In addition, work on at-risk units fed from a common feeder will be planned to be executed in the same year. The asset condition data collected from inspections will be leveraged to prioritize the high failure risk units within the asset class. Severely deteriorated and non-submersible units located in areas prone to flooding will be given the highest priority. Projects can be reprioritized if an urgent need is discovered.

E6.4.4.2 Network Vault Renewal

The Network Vault Renewal segment rebuilds vaults and vault roofs. From 2020 to 2022, Toronto Hydro spent $30.9 million to rehabilitate (or decommission) 20 vaults. Toronto Hydro expects to spend $19.0 million to address 23 vaults. Table 10 below provides the year over year breakdown of Network Vault Renewal investment spending including the actual historical spending from 2020-2022 and the bridge year estimates for 2023-2024. Table 11 provides a breakdown of the number of units attained in 2020-2022 and planned to be completed in the bridge years from 2023-2024.

Table 10: Network Vaults Renewals - Actual/Bridge ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Network Vault Renewal	6.1	9.1	15.7	10.4	8.6	6.7	6.9	18.0	18.5	19.0

Table 11: Volumes Actual/Bridge

	Actual			Bridge		Total
	2020	**2021**	**2022**	**2023**	**2024**	
Vault Rebuild	9	3	4	8	9	43
Roof Rebuild	0	0	3	5	1	
Vault Decommission	0	1	0	0	0	

First, it should be noted that year-over-year fluctuations are primarily due to costs associated with particular vaults. Costs for civil work tend to vary significantly between projects as such projects tend to impact third-party infrastructure in close proximity. Furthermore, civil construction projects are impacted by timing and constraints imposed by other major City work, such as the Eglinton Crosstown LRT.

Between 2020-2024, Toronto Hydro has increased pacing and will proactively rebuild 10 additional network vaults than planned in 2024 in order to further reduce safety risks to Toronto Hydro employees and the public. Related to this, the costs for vault rebuilds have increased. This can be attributed to certain factors such as City permits only allowing more expensive nighttime work to be completed at certain locations, as well as the costs of civil work tending to vary greatly as projects are heavily impacted by the City and other utility infrastructure in the vicinity.

Furthermore, over the 2020-24 rate period, Toronto Hydro has completed an increased amount of legacy cable removal and upgrade work that was completed in the course of building new network vaults. A number of the targeted vaults contained AILC secondary cable, containing asbestos and lead, and/or have PILC cable that terminates at the network units. In the same vein, additional civil work was completed at certain locations to replace existing two units network vault by building two single unit vaults. This approach helps to save one network unit from catastrophic failure in case of a vault fire; only one network unit will be impacted rather than both units.

Moreover, the supply chain issues originating from the beginning of the pandemic proved to be a significant challenge for Toronto Hydro. As a result of factory closures in early 2020, freight costs and delivery times were heavily impacted and increased significantly. Furthermore, lockdowns worldwide, labour shortages, strong demand for tradeable commodities, interruptions to logistics networks, capacity issues, and material cost increases driven by raw material price increases were are all present throughout the 2020-2024 rate period.

Without intervention, Toronto Hydro forecasts that 137 network vaults will have at least material deterioration (HI4 and HI5) by 2029. Toronto Hydro therefore plans to spend $69.0 million to address 38 of the highest risk vaults during the 2025-2029 rate period (i.e. approximately seven vaults per year), which is in line with the 2020-2024 pace of renewal for these assets. A focust on replacement of units with the highest failure risk is expected to maintain downtown reliability and reduce the safety and environmental risk associated with those units. Table 12 below provides the proposed year over year breakdown of units to be addressed from 2025-2029.

Table 12: Proposed Number of Units - Network Vault Renewal

Year	2025	2026	2027	2028	2029
Vault Rebuild	3	3	7	7	7
Roof Rebuild	0	0	3	2	3
Vault Decommission	0	0	1	1	1

Through this work, Toronto Hydro expects to improve safety and maintain reliability by removing potential trip and falling debris hazards and reducing the risk that any structural deficiencies could lead to damaged equipment. Where applicable, Network Vault Renewal work is combined with overlapping work in the other Network System segments to minimize resource requirements and costs. In addition, projects requiring civil construction work are coordinated with planned City road work to reduce costs associated with routing civil infrastructure around road moratoriums and road cut repairs.

E6.4.4.3 Network Circuit Reconfiguration

The Network Circuit Reconfiguration segment mitigates the impact of multiple contingency events on Toronto Hydro’s network system. Throughout 2020-2022, Toronto Hydro spent $7.6 million on this segment and expects to spend $1.4 million over 2023-2024. Table 14 below provides the status of planned network circuit reconfiguration work for 2020-2024. This also includes the carryover work from the 2015-2019 rate period.

Table 13: Historical & Forecast Network Circuit Reconfiguration Expenditures ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Network Circuit Reconfiguration	1.2	3.1	3.3	0.7	0.8	0.8	1.5	0.8	-	-

Table 14: Summary Status of Planned Projects 2020-2024

Network	Completion Year	CapEx ($ Millions)	Comments
Hammersmith Network Preparation	2021-2022	6.5	Carry Over Projects form 2015-2019 Rate Filing Period
Hammersmith Loc 4141 Ci			

Hammersmith Network Conv			
LOC 4174 Vault Rebuild to CC			
Carlaw E Network			
GD Phase 1	2021	0.88	Actuals: 2020-2022
A-North Phase-1	2023	1.7	Bridge Years: 2023-2024
CE-North (Carry Over)	2024		
CE-South Phase 1	2024		
GD Phase 2	2026	3.2	Forecast: 2025-2029
A-North Phase 2	2025		
CE-South Phase2	2027		
WR-West Phase 1	Beyond 2029		
WR-West Phase 2			
CS-West Phase1			
CS-West Phase2			

The variances between planned vs actual historical work, or planned vs forecast bridge years work for this segment has been due the following reasons:

- A large portion of the capital expenditures were dedicated to the completion of the carryover work from the 2015-2019 rate period including Hammersmith and Carlaw East Networks (approximately $6.5 Million).
- Material costs have increased significantly due to the COVID-19 pandemic and related supply chain issues, which resulted in increased raw material prices.
- Additional labour costs incurred due to overtime work mandated by the City's work zone coordinator, additional splicing work required on GD Phase-1 due to complexity of network and for handling of TTC cables and gas main found in the proximity of the cable chambers involved in reconfiguration process.
- Increased amount of legacy cable removal and upgrade work completed while reconfiguring the network secondary, as explained in Exhibit 2B, Section E6.3.
- At certain locations unanticipated civil work was completed during project execution due to location requirements.

Toronto Hydro plans to spend $3.2 million to reconfigure parts of three networks over the 2025-2029 rate period. Table 15 below lists the targeted networks for 2025-2029, these three networks are carried over from 2020-2024 rate period. These phases correspond to parts of the five largest networks and Toronto Hydro expects that the reconfigurations will help to improve outage restoration times and reduce the risks associated with second contingency events for downtown network customers.

Table 15: Planned Network circuit reconfiguration Projects for 2025-2029

Network	Network Feeders	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Reconfiguration Year	CapEx ($ Million)
A-North Phase 2	9	22	15	2025	3.2
GD Phase 2	9	25	20	2026	
CE-South Phase2	8	16	7	2027	

To minimize costs and resource requirements, Network Circuit Reconfiguration projects are combined with overlapping work in the other Network System Renewal segments, where applicable. Reconfiguration work can vary significantly from one network to another and this continues to hold true during the 2025-2029 rate period, where the four targeted networks service some of the largest loads with complex configurations.

E6.4.5 Options Analysis

E6.4.5.1 Options for Network Unit Renewal

Toronto Hydro considered the following options for addressing high failure risk network units.

9. Option 1: Reduced Pace

Under this option, Toronto Hydro would only target the 42 network units expected to be in at least "material deterioration" (HI4/5) by the end of 2029. While this option would mitigate reliability risks over the 2025-2029 rate period, with over 50 percent of network units expected to be at or beyond useful life by 2034, a reduced pace of asset renewal would result in a higher risk of power outages due to failure risk in the next decade. Therefore, to manage failure risk in the long term, Toronto Hydro would need to invest more to replace higher volumes of work in the next period at a higher cost. This would also reduce efficiency as it may require higher amounts of reactice and emergency work. As such, this option is not viable given the risks posed by these assets which include catastrophic failure due to poor condition; flooding; employee and public safety risks as well as environmental risks (e.g. oil leaks).

10. Option 2: Moderate Pace (Selected Option)

This option would address safety risks associated with deteriorating network units that would deliver reliability and efficiency benefits for the network system. At a pace of 26 units per year, 130 network units would be replaced and their associated safety, environmental and reliability risks addressed. These would address some legacy, non-submersible units in at least material deterioration thus minimizing the risk of failure due to flooding. Under this option, the utility expects the replacement of network units would result in avoided direct and indirect costs associated with asset failures across both periods, including but not limited to the cost of customer interruptions, emergency repair and replacement across the 2025-2029 rate period and beyond.

With over 50 percent of the network units expected to reach or go beyond useful life by 2034, the pace under this option would be expected to mitigate the risks associated with deteriorating and non-submersible network units and improve efficiency of the network system. However, units not replaced by 2029 or in a timely manner would continue to pose a higher risk of failure with the potential to cause fires or oil leaks until they are replaced. Some legacy, non-submersible units without material deterioration at an elevated risk of failure due to flooding, would also remain unaddressed.

This option is recommended as it reflects an appropriate trade-off between mitigating safety and environmental risks, reliability impacts, resource constraints, and program cost both in the short-term and in the future.

11. Option 3: Accelerated Pace

Under this option Toronto Hydro would replace network units at an accelerated rate of 40 units per year to achieve faster reduction of safety and reliability risks associated with deteriorating and high failure risk network units. At this pace, Toronto Hydro would replace all of the 149 units forecast to have material deterioration (by 2029) and address an additional 51 units forecast to be at or beyond useful life in the next decade. While this option would minimize the number of network units at elevated risk of failure and would enable the utility to balance the number of units replaced across the 2025-2029 and 2030-2034 rate periods, it would cost roughly 1.5 times more than the proposed plan. As Customer Engagement results note that customers are supportive of Toronto Hydro's current pacing, this option cannot be justified. Additionally, this pace would not align with the utility's resources and system constraints. For these reasons, Option 3 is not a feasible strategy.

E6.4.5.2 Options for Network Vault Renewal

Toronto Hydro considered the following options for addressing network vaults in poor condition.

12. Option 1: Reduced Pace

In this option, Toronto Hydro would address immediate structural deficiencies of high-risk network vaults identified through the ACA process as having at least material deterioration ("HI4") at a reduced pace. The investment would only target about 22 network vaults (approximately 52 % of network vaults projected to reach HI4/HI5 from 2025 to 2029) thus it will significantly increase the backlog of HI4/HI5 vaults in the system that exists at the start of the 2025-2029 rate period. This option would not replace vaults at either the rate at which the HI4/HI5 population grow by each year, or the rate at which vaults on average reach normal lifespan.

This option is not viable as the multitude of issues discussed throughout the narrative, including structural failure may lead to failure of the equipment housed inside the vaults. Furthermore, safety risks (e.g. tripping, falling debris and fire hazards) for both the public and Toronto Hydro crews would be elevated. Major structural issues cannot be addressed through maintenance work.

13. Option 2 : Moderate Pace (Selected Option)

In this option, Toronto Hydro would proactively address the 38 network vaults which have at least material deterioration (HI4) at a modest pace to reduce the risk of injury to the public and Toronto Hydro crews and the risk to system performance due to asset failure. At a pace of approximately 7 network vaults per year, this option would maintain the number of network vaults projected to reach HI4/HI5 at the level expected for 2025 but would not eliminate the backlog of HI4/HI5 vaults expected at the start of 2025. Based on historical experience, Toronto Hydro projects this pace to be achievable and would help mitigate the forecasted rise in the number of network vaults with material deterioration over the 2025-2029 rate period. Although Toronto Hydro would address the highest risk vaults, there would still be over 85 network vaults that have at least material deterioration (HI4) at the end of 2029. The backlog of these vaults would continue to pose elevated safety and reliability risks. However, this option would be expected to mitigate risks to an acceptable degree at a pace of work that would be realistic to achieve and at a reasonable cost.

14. Option 3: Accelerated Pace

By accelerating the pace of network vault renewal, Toronto Hydro would address the network vaults at an accelerated rate of 9 vaults per year to achieve faster reduction of safety and reliability risks associated with deteriorated and high failure risk network vaults. At this pace, Toronto Hydro would address more than the 42 network vaults forecast to have at least material deterioration (from 2025 to 2029) and would also slightly reduce the backlog of HI4/HI5 vaults discussed in above options. Reliability and safety risks of deteriorated network vaults would be reduced faster and to a greater degree than option 2 above but it would cost approximately 1.3 times more than the proposed pace for this segment. As Customer Engagement results note that customers are generally supportive of Toronto Hydro's current plan pacing, this would not be justifiable. In addition, this pace poses issues with resource and outage management resulting in delays of other planned work needed for the system. Therefore, this is not a recommended option.

E6.4.5.3 Options for Network Circuit Reconfiguration

15. Option 1: Reduced Pace (Selected Option)

This option for the 2025-2029 rate period would address three networks with reduced pace at a cost of $3.2 million. This would include completion of the GD Phase-2, A-North Phase-2, CE-South Phase-2. It would reduce the workload required to stabilize the networks and restore customers following multiple contingency events and reduce the time required to restore the networks to normal operation. The networks targeted under this option service large loads and have complex configurations, which means that they would benefit the most from reconfiguration.

There would be no additional network circuit reconfigurations work planned other than the carryover work from the last rate filing, detailed in Section E6.4.4.3. This will carry the risks of dropping other entire networks under 2nd contingency events into future years. It is the lowest cost option to complete the specified portion of carry-over work and improve the operability of three major networks under 2nd contingency events.

16. Option 2 : Moderate Pace

Under this option, Toronto Hydro would require $4.1 million to complete the projects mentioned in Option 1 plus CE-South Phase-2 network addition. This strategy would attain a total of 4 networks reconfigured rather than partially completed. Historically, network circuit reconfiguration projects have taken a long time to design and execute due to complexity of the secondary system in the downtown core. This can be attributed to the fact that a lot of civil infrastructure may need to be inspected to ensure that the proposed secondary cable reinforcements can be accomplished. Furthermore, as civil deficiencies are discovered, costs to rebuild civil may cause the cost of the projects to increase significantly. External to the program budget, Toronto Hydro spent $6.5 million to address carryover of work from the 2015-2019 rate period (See: Section E6.4.4.3). While this option would reconfigure two additional networks, it would cost roughly 1.5 times more than the proposed pace as well as not aligning with the utility's resources and system constraints. For these reasons, Option 2 is not recommended.

17. Option 3: Accelerated Pace

The improvement option would require $5.22 million to complete all five major networks. These networks are George & Duke, Windsor-West, Terauley-North, Charles-West, Cecil-South and Terauley-East. As reconfiguration projects have historically taken a long time to design, attempting to fit more projects within this 5-year period poses a feasibility risk. All major networks, covering large geographic areas of the downtown core, reside in areas of the city with aging infrastructure. As civil deficiencies are discovered, costs to rebuild civil may cause the cost of the projects to increase significantly, outside the budget of the program. Toronto Hydro estimates that this would require approximately double the financial and labour resources per year compared to the selected option and is therefore not recommended.

E6.4.6 Execution Risks & Mitigation

The Network System Renewal program is subject to the risks facing downtown underground programs and projects. For all segments, these risks include summer feeder restrictions. More specifically, many downtown network feeders have summer feeder switching restrictions imposed to prevent overloading cables and equipment during peak loading periods. To mitigate this risk, projects are scheduled to avoid the summer period if the feeders involved are restricted (i.e. do not have capacity). If a feeder is newly restricted in the project year, the project timeslot could potentially be exchanged with another project. If a restricted feeder supplies a vault being planned for rebuild, then the work may only be conducted during off-peak hours, and this may hinder project execution. Toronto Hydro's Load Demand program for the 2025-2029 rate application(see Exhibit 2B, Section E5.4 of the Distribution System Plan) is intended to help mitigate these risks by enhancing the grid so that feeder restrictions during summer peak times are minimized.

Each segment may also be subject to its own set of additional risks as discussed below:

- The City and Toronto Hydro's customers often have special events scheduled that can be negatively impacted by a major construction project. Toronto Hydro communicates with stakeholders and customers to establish an agreeable timeline in accordance with system priorities. Should a conflict arise, the project timeslot could potentially be exchanged with another project to allow the overall Program to proceed without negative impact.
- As part of Network safety enhancements, the unit cost of Network units will likely increase in the next few years. Some of the safety enhancements under consideration are:
  - External upper link boxes on protectors
  - New style antlers on protectors
  - Ethernet ready protector relay
  - Pro link style disconnect switches
- The removal of a network unit may cause the remaining network units to experience overloads. Toronto Hydro manages this risk by scheduling the replacement of problematic network units outside of the peak loading periods of the particular vault. For example, work on vaults supplying schools or buildings with electric heat may best be scheduled during the summer.
- City moratoriums and the Metrolinx subway expansion may impact execution timelines. Although existing City moratoriums are considered when planning vault renewal projects, it is possible that new moratoriums may be subsequently introduced. To mitigate this risk, Toronto Hydro reviews all new moratoriums and adjusts its work plans accordingly. Projects, such as the expansion of the transit system in Toronto, pose unique challenges. When such projects are in the execution phase, the City or Metrolinx may impose moratoriums that suspend all other work until critical phases of transit projects are completed. In addition, transit construction may require relocation of Toronto Hydro assets that impacts the Vault Renewal program. To mitigate this risk, Toronto Hydro communicates with Metrolinx on a continual basis to identify, monitor, and resolve conflicts.
- For the Network Circuit Reconfiguration segment, additional risks are posed by structures at the end of their useful lives and customer-owned civil structures. Projects in this segment typically involve the installation of new cabling within existing cable chambers and duct

structures. There is a risk that the required structures will be at the end of their useful lives and may require replacement before the planned work can be executed. This would necessitate scope and timing changes to some projects. However, there are usually multiple options to reconfigure a network. Should the optimal design require civil structure replacement, an alternative that still provides the required reliability and operational benefits, but that does not require civil structure replacement, can likely be found. The design would be revised accordingly to mitigate the cost and timing impacts.

- There also may be unforeseen condition or access problems with some customer-owned civil structures. In these situations, the customer may have to perform civil rebuild work before Toronto Hydro's work can commence, thereby causing project delays. This risk can be mitigated by fully inspecting all civil plants prior to finalizing project design, and introducing sufficient lead times for customer civil design and construction activities in the project schedule.

Since the pandemic's beginning, supply chain disruptions have grown to be a significant challenge for Toronto Hydro. Freight costs and delivery times have significantly increased as a result of factory closures in early 2020, lockdowns in various nations across the world, labour shortages, strong demand for tradeable commodities, interruptions to logistics networks, and capacity issues. It is expected that by 2025-2029, capacity constraints and labor shortages should ease, taking some of the pressure off supply chains and delivery times. To mitigate this risk, Toronto Hydro's procurement department will work closely with our suppliers and monitor manufacturing and delivery times closely to maintain project completion dates.

E6.5 Overhead System Renewal

E6.5.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 218.9	**2025-2029 Cost ($M):** 358.4
Segments: Overhead System Renewal, Overhead Infrastructure Resiliency	
Trigger Driver: Failure Risk	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Environment, Operational Effectiveness – Safety, Financial Performance	

The Overhead System Renewal program (the "Program") manages failure risk on Toronto Hydro's overhead system through the replacement of end-of-life and functionally obsolete assets that are in poor condition or otherwise require replacement to mitigate safety and environmental risks.

Additionally, the 2025-2029 iteration of this Program reintroduces the undergrounding or relocation of parts of Toronto Hydro's overhead system that are particularly vulnerable to external causes of failure or hard to access.

The Program is grouped into the two segments summarized below:

- **Overhead System Renewal:** This segment is a continuation of the Overhead System Renewal program outlined in Toronto Hydro's 2020-2024 Distribution System Plan ("DSP").[1] This segment addresses three major asset classes that are sufficiently critical as to require proactive lifecycle management strategies: (1) pole-top transformers; (2) poles and pole accessories; and (3) overhead switches. The probability that these assets will fail – causing negative impacts to safety, reliability, and the environment – increases as these assets age and deteriorate.

  The Overhead System Renewal segment consists of both rebuild and spot replacement projects. Rebuild projects are ideal when a confluence of conditions within a concentrated geographical area make it necessary and/or economically prudent to rebuild an entire section of the system. For example, areas of the system with a high concentration of assets at risk of failure (e.g. due to deteriorated condition) and a history of poor reliability are

[1] EB-2018-0165, Exhibit 2B, Section E6.5

typically addressed through rebuild projects. Voltage conversion is another important consideration for rebuilds. For example, Toronto Hydro has a significant population of deteriorating, legacy 4 kV overhead lines that it will gradually convert to modernized 13.8 kV or 27.6 kV standards in order to improve operational performance and efficiency and prepare for the demands of electrification, growth, and the proliferation of distributed energy resources ("DERs"). As 4 kV is no longer an accepted system standard, the deterioration of 4 kV asset condition and performance within an area will generally trigger a rebuild of the area to current standards.

Outside of rebuild project areas, any transformers at risk of containing PCBs greater than 2 ppm, will be addressed through targeted spot replacement projects. These projects do not involve the replacement of all assets in a continuous area.

A summary of this segment's investments in the three major overhead asset classes is as follows:

- **Pole-top Transformers:** One of the main drivers of poor performance in the overhead system is defective equipment. Through the focused renewal of PCB containing transformers (which are also past useful life and therefore at higher risk of failure) in recent years, Toronto Hydro has reduced the number of transformer-related customers interrupted and customer hours interrupted from over 10,000 customers interrupted and 6,000 customer hours interrupted and per year on average to 4,133 customers and 4,360 customer-hours interrupted per year on average over the last five years (2018-2022). This focused renewal has also reduced the proportion of overhead transformers past useful life from approximately 14 percent in 2017 to approximately 8 percent at the end of 2022. However, without further intervention, that number will return to 17 percent by 2029. By replacing all remaining PCB transformers by the end of 2025 and then shifting to steady transformer replacement through rebuilds of high-risk and poor performing areas, Toronto Hydro can ensure that the overhead transformers past useful life and the associated reliability and environmental risks remain within a reasonable range over 2025-2029 and beyond.
- **Poles and Accessories:** Pole failures can lead to extensive and prolonged service disruptions, as well as pose safety risks for utility crews and the public. Poles and pole accessories have contributed to over 30,700 customer interruptions and 18,000

customer hours interrupted per year on average over the past five years. Poles are frequently exposed to various severe weather conditions, and may become vulnerable to internal rot, decay, and infestation. These conditions, combined with the fact that approximately 23 percent of Toronto Hydro's wood poles are beyond their useful life as of 2022, make these poles more susceptible to failure. Approximately 9 percent of wood poles are already showing signs of material deterioration (as of 2022) and, without intervention, this proportion is forecast to increase to 30 percent by 2029. Toronto Hydro plans to replace a total of approximately 8,300 wood poles and associated accessories over the 2025-2029 period to reduce the aforementioned failure and safety risks.

  - **Overhead Switches**: Overhead switches are constantly exposed to harsh environmental conditions. Their failure often leads to prolonged outages and can pose significant safety risks to utility workers if an arc flash happens during the switch failure. On average, overhead switches contributed to 37,070 customer interruptions and 20,263 customer hours interrupted annually between 2018 and 2022. Approximately 18 percent of gang operated switches and 33 percent of inline disconnect switches have reached the end of their useful life as of 2022. Toronto Hydro plans to replace a total of 510 overhead switches through rebuilds of areas with high concentrations of high-risk assets and poor reliability.

- **Overhead Infrastructure Resiliency**: This segment is a reintroduction and expansion of the work done through the Overhead Infrastructure Relocation program in Toronto Hydro's 2015-2019 DSP[2] to improve the resiliency of the overhead system through targeted relocation and undergrounding of overhead assets as summarized below:
  - Undergrounding critical sections of overhead infrastructure that are persistently affected by outages caused by external factors, such as adverse weather events and tree contacts, to reduce the frequency and impact of these types of outages for affected customers;
  - Relocating overhead sections in areas with limited access, such as heavily treed ravines, valleys, rail corridors, Hydro One rights-of-way ("ROW"), and certain trunk sections running along inaccessible rear lot locations.[3] These sections can be especially vulnerable

[2] EB-2014-0116, Exhibit 2B, Section E6.5.
[3] Note most rear lot assets are being addressed through the Area Conversion program, see Exhibit 2B, Section E6.1.

during major storm events such as heavy rainfall, floods, and ice storms and restoration following major storms is extremely challenging; and

- Reconfiguring and, if necessary, undergrounding pole lines exiting stations that carry three or more circuits (referred to as congested egresses), which pose an unacceptable reliability risk due to vulnerability to factors such as adverse weather and the high number of customers connected to a single physical location.

The objectives of the Overhead System Renewal program for the 2025-2029 rate period are to:

- Renew deteriorated assets at a pace that aims to generally maintain asset condition and failure risk on the overhead system at current levels;
- Maintain overall system reliability and improve reliability for certain poorly performing areas of the overhead distribution system;
- Address the environmental risks of potential PCB oil spills by replacing all remaining transformers containing or at risk of containing PCBs; and
- Improve resiliency through targeted undergrounding or relocation of overhead assets that are at risk of adverse weather, tree contacts, animal contact, foreign interference and/or in areas that are difficult to access.

E6.5.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's objectives and obligations to connect low and high voltage customers within 5 and 10 business days respectively at least 90 percent of the time (pursuant to the OEB's new connection metrics and section 7.2 of the Distribution System Code ("DSC")), by increasing overhead system capacity through voltage conversion from 4 kV and/or 13.8 kV to 27.6 kV in specified areas.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (as measured via metrics like SAIFI, SAIDI, FESI-7, System Health (poles)) by: ○ controlling the population of HI4 and HI5 condition[4] poles over the 2025-2029 period;

[4] For many of its major assets, Toronto Hydro performs asset condition assessment ("ACA"), in which the condition of each asset is assigned a health index ("HI") band from HI1 to HI5, where HI5 indicates the worst condition. For these same assets, the utility can then also project future condition (i.e. HI band) assuming no intervention. See Exhibit 2B, Section D, Appendix A for more details on Toronto Hydro's ACA methodology

	○ replacing pole-top transformers at higher risk of failure through area rebuild and spot replacement; and ○ Relocating and/or undergrounding assets in hard to access or vulnerable locations.
Environment	• Contributes to improving Toronto Hydro's Spills of Oil Containing PCBs measure, and environmental objectives and obligations by eliminating all equipment containing, or at risk of containing, PCBs from the overhead distribution system by the end of 2025 pursuant to PCB regulations (PCB Regulations,[5] made under the federal *Canadian Environmental Protection Act, 1999 and* Ontario's *Environmental Protection Act, 1990*[6] and, City of Toronto's Sewer Use By-Law.[7]
Operational Effectiveness - Safety	• Toronto Hydro and contractor crew safety improved by relocating assets to improve accessibility
Financial Performance	• Voltage conversions enables a reduction in line losses which in turn leads to savings for our customers. • Once an MS Station's feeders have been fully voltage converted; the Station is decommissioned which results in reduced need for capital and maintenance investment. • Improve maintenance costs incurred on assets located at inaccessible locations by relocating assets to areas of better access

[5] PCB Regulations (SOR /2008-273), under the *Canadian Environmental Protection Act,* 1999.
[6] *Environmental Protection Act,* RSO 1990, c E. 19.
[7] City of Toronto, by-law No 681, *Sewers,* (May 15, 2023).

E6.5.3 Drivers and Need

Table 3: Drivers and Need

Trigger Driver	Failure risk
Secondary Driver(s)	Environmental Risk, Reliability, Safety, Functional Obsolescence, System Efficiency

The Overhead System Renewal program is driven by failure risk of assets on the Overhead System due to age, condition, obsolete design or location, which can negatively impact reliability, safety, and the environment. The Program replaces at-risk assets and, where appropriate, will relocate or underground them to address location-specific vulnerabilities.

E6.5.3.1 Overhead System Renewal

The Overhead System Renewal segment focuses on replacing three types of assets: (i) pole-top transformers; (ii) poles and accessories; and (iii) overhead switches. This renewal segment is driven by the risk and impact of overhead distribution asset failures on system reliability and safety due to accelerated asset condition degradation resulting from factors such as: sustained exposure to dirt, salt, dust, moisture and humidity, and assets approaching end of their useful life. Customer Engagement results have shown that reliability is a top priority for all types of customers.[8]

Asset failures on Toronto Hydro's distribution system present reliability risks (which can lead to outages and directly impact customers), environmental risks (e.g. oil spills into the environment), and safety risks (e.g. stemming from electrical contacts, arc flashes, and potentially catastrophic fires). Timely replacements are required to avoid the distribution system being operated under contingency conditions (i.e. with interrupted feeders or assets that cannot provide backup supply in the event of a subsequent outage).

Over the last five years the main known cause of outages in the overhead system is defective equipment as shown in Figure 1. Foreign interference is the second main known cause of outages and these are addressed primarily through the Worst Performing Feeder segment.[9] Without renewal, the risk of overhead asset deterioration and failures would increase, resulting in more frequent and longer outages which would result in an increase in reactive replacement work.

[8] Exhibit 1B, Tab 3, Schedule 1
[9] Exhibit 2B, Section E6.7

Figure 2 shows the volume of reactive capital work requests generated to address overhead system related deficiencies between 2019 and 2022. On average, about 463 such work requests were initiated annually over that period, which is an improvement compared to the 2013-2017 average of 550 per year. Timely replacement of aged and deteriorated equipment before failure can effectively mitigate the frequency and duration of interruptions experienced by customers due to failing overhead assets.

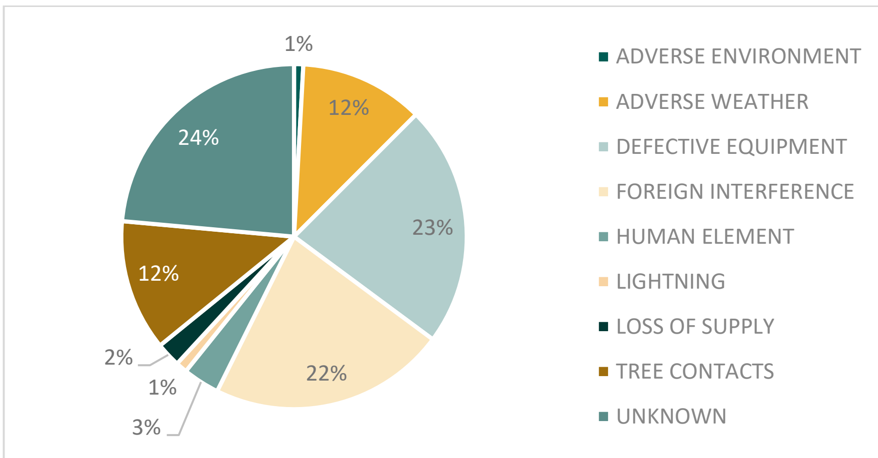


Figure 1: Overhead System Outages by Cause Code 2018-2022 (Excluding MEDs and Planned Outages)

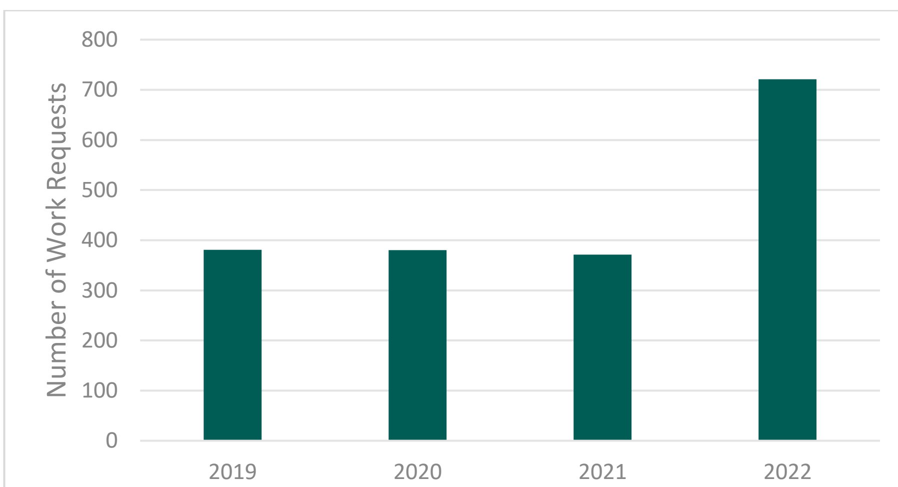


Figure 2: Reactive Work Requests to replace Overhead Assets from 2019-2022[10]

[10] 2018 data is excluded due to the transition to SAP that occurred during that year

The reliability outcome of historical investments in the Overhead System Renewal program is illustrated in Figures 3 and 4, which illustrate the effects of outages on customers; customers interrupted ("CI") and customer hours interrupted ("CHI"). Compared to 2013-2017, on average system wide reliability measures have remained steady. This result is consistent with the objectives that Toronto Hydro set out to achieve in the previous rate application, which was to maintain overall reliability.

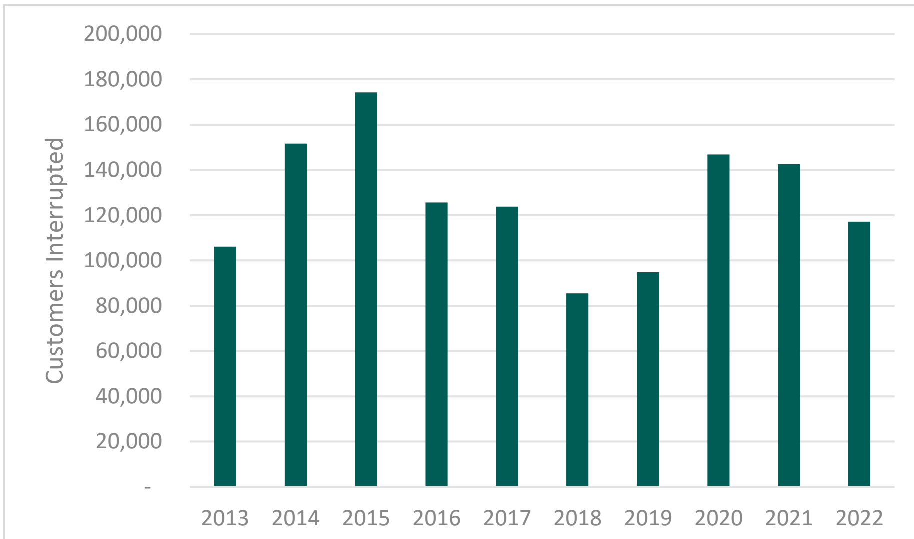


Figure 3: Customers Interrupted ("CI") on the Overhead System (2013-2022)

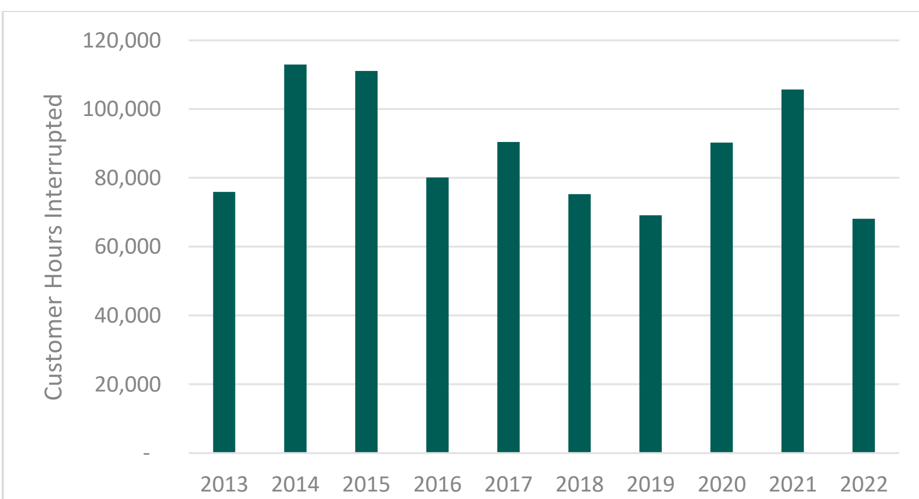


Figure 4: Customer Hours Interrupted ("CHI") on the Overhead System (2013-2022)

Toronto Hydro must slightly increase its pace of investment in the Overhead System Renewal segment in order to prevent reliability risk from increasing. Asset investment is necessary to address the large number of overhead assets that are expected to deteriorate in the coming years as they approach the end of their useful life or remain in service well beyond it.

Table 3 summarizes the age demographics for poles, transformers and switches in 2022 and by 2029 (without investment).

Table 3: Asset Demographics

	Population	Typical Useful Life (Years)	Assets Past Useful Life as of 2022 (%)	Assets Past Useful Life in 2029 without Investment (%)
Wood Poles	108,988	45	23	29
Concrete Poles	49,059	55	13	22
Overhead Transformers	27,690	35	8	17
Overhead Load Break Gang Operated Switches	3,015	30	18	26
Overhead Disconnect Switches	4,425	30	33	54

Table 4 shows the condition of Toronto Hydro's poles in 2022 and by 2029 (without investment).

Table 4: Condition Data for Wood Pole

Asset Condition Index	2022	2029 (Without Investment)
HI1 – New or Good Condition	68,193	60,253
HI2 – Minor Deterioration	7,536	8,310
HI3 – Moderate Deterioration	21,015	5,544
HI4 – Material Deterioration	8,918	24,404
HI5 – End-of-serviceable Life	504	7,655

Through a combination of spot replacements and complete rebuilds of areas with poor reliability and large concentrations of high-risk assets, Toronto Hydro plans to replace approximately 4,848 overhead transformers, 8,338 poles, and 510 switches over the 2025-2029 period.

Any targeted overhead areas that still utilize 4.16 kV or 13.8 kV systems will be converted to 27.6 kV. The underground portion of these feeders is addressed by the Underground System Renewal - Horseshoe program.[11] Likewise, there are 4.16 kV systems in the rear lot, or the backyards, of customers that are addressed by the Area Conversions program.[12] There is a growing number of 4 kV and 13.8 kV feeders where customers have sustained outages (sometimes multiple) of ten hours or more. These are legacy assets which cannot be easily replaced, and their configurations do not allow for expansion or provide many options for system restoration contingency. Converting to 27.6 kV is expected to:

- enhance power quality with less voltage drop for customers at the ends of distribution lines;
- reduce line losses, improving the efficiency of the distribution system;
- modernize the system to prepare for the demands of electrification, growth, and the proliferation of DERs that the 4kV cannot accommodate; and
- enable the eventual decommissioning of Municipal Stations, thereby avoiding operating and maintenance expenditures that would otherwise need to be incurred.

There are approximately 170 4.16 kV and 13.8 kV feeders remaining to be converted throughout both the underground and overhead system in the Horseshoe. Toronto Hydro is planning to convert the overhead portions of 48 of these feeders and the underground portions of 29 of these feeders by 2029. At this pacing Toronto Hydro expects to complete the overhead voltage conversion portion of the entire system by 2049.

1. Replacement of Overhead Transformers

Through the Overhead System Renewal segment, Toronto Hydro replaces overhead transformers beyond useful life, which are at risk of failing and potentially posing an environmental risk due to oil leaks that may contain PCBs. There are currently 27,690 overhead transformers in Toronto Hydro's distribution system. As a critical component of Toronto Hydro's overhead system, transformers are used to step down primary distribution voltage to levels required to supply residential and commercial customers. They are mounted on poles and consistently exposed to external elements that cause degradation (e.g. weather conditions, dust, salt, moisture, cyclical loading, faults and humidity). In particular, exposure to precipitation and humidity over time causes corrosion (tank perforation) which can lead to oil leakage into the environment. Figure 5 shows the reactive work

[11] Exhibit 2B, Section E6.2.
[12] Exhibit 2B, Section E6.1.

requests to replace failed or severely deteriorated pole-top transformers during the 2019-2022 period. Figure 6 shows the forced pole-top outages during the 2018-2022 period (note not all reactive work is tied to an outage).

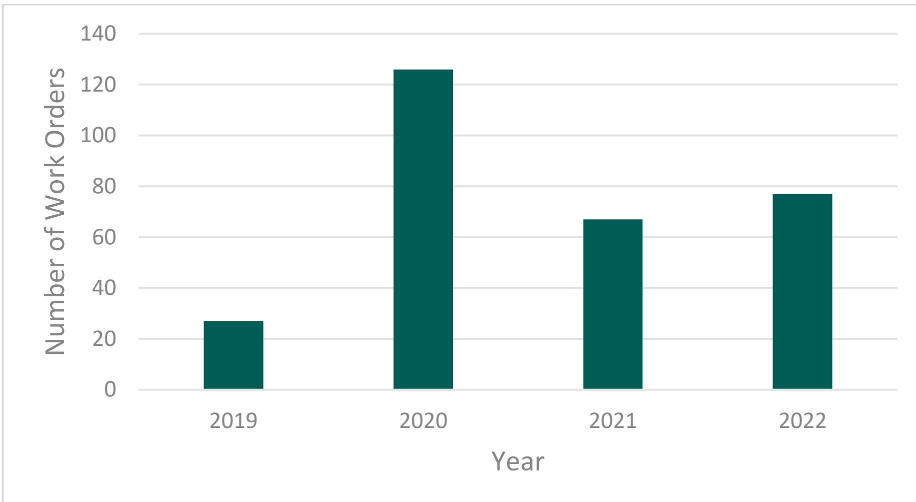


Figure 5: Reactive Work Requests for Pole-top Transformer Replacement[13]

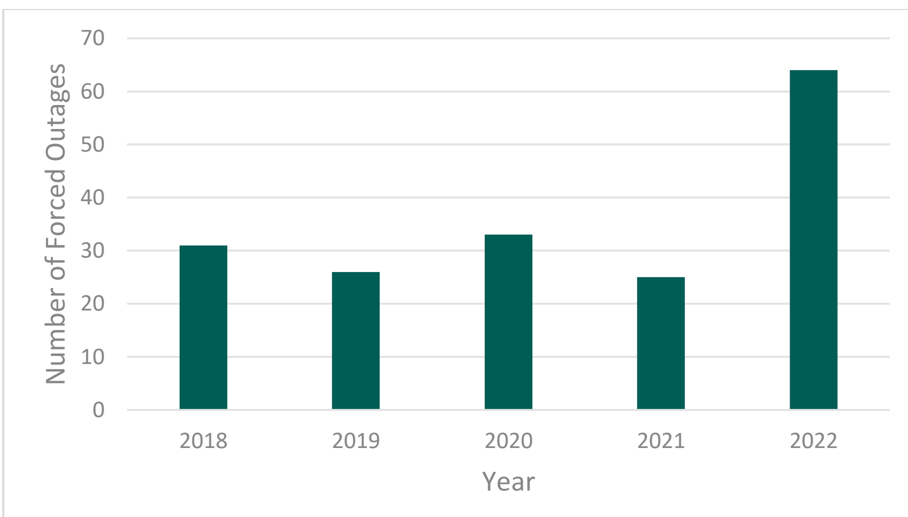


Figure 6: Forced Outages for Pole-top Transformers

On-going renewal work has contributed to an overall average decline in reactive work requests, however in 2022 there was a spike of 64 outages (versus an average of 35 outages over the five-year

[13] 2018 data is excluded due to the transition to SAP that occurred during that year

period). The vast majority of outages relate to transformer failures (approximately 31 to 64 failures per year), contributing to over 4,133 CI and 4,360 CHI over the same period on average (see Figures 7 and 8). In 2022, consistent with the number of outages, both CI and CHI have noticeably increased compared to recent averages – to 7,643 customers and 8,588 hours, respectively. This can be explained in part by the fact that Toronto Hydro has recently implemented more granular automated outage reporting as discussed in Exhibit 2B, Section C. There was also an abnormal number of customers interrupted because of one individual incident. Similarly, the increase of CI in 2020 is attributed to a single outage impacting a relatively large number of customers.

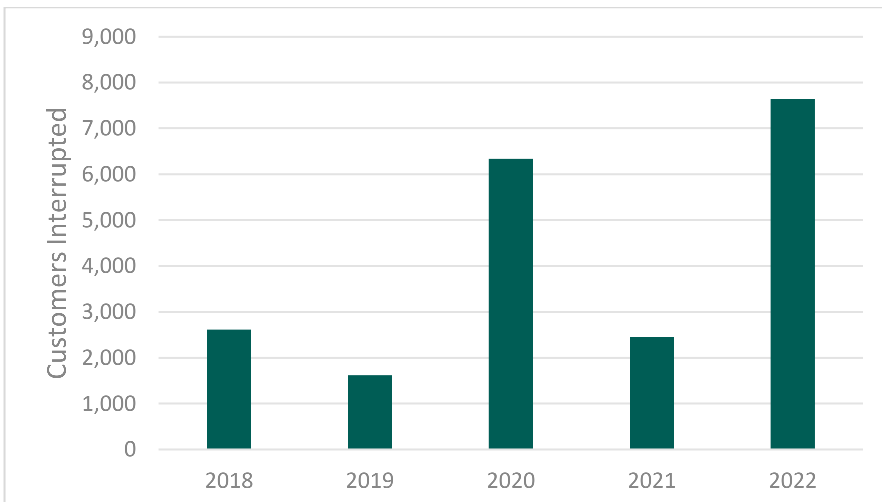


Figure 7: Customers Interrupted ("CI") for Pole-top Transformers

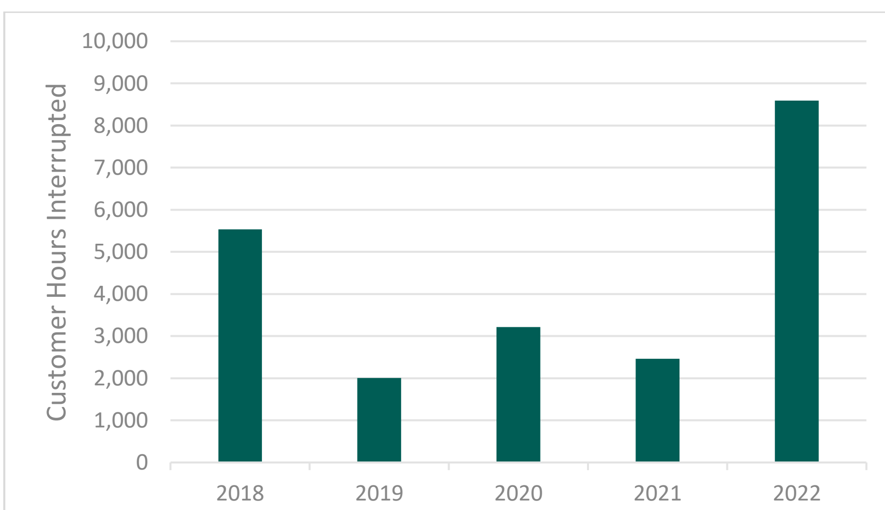


Figure 8: Customer Hours Interrupted ("CHI") for Pole-top Transformers

A number of overhead transformer failures have resulted in oil leaks into the environment. Figure 9 shows the total number of reported oil spill incidents for pole-top transformers during the 2018-2022 period. In recent years the number of spills has declined as Toronto Hydro has targeted the most at-risk transformers for replacement, aiming to replace these transformers prior to failure or before spills can occur. Specifically, older transformers are at an especially high risk of having oil containing PCBs. Releasing oil containing PCBs (or oil on its own) into the environment may be a breach of the federal *Canadian Environmental Protection Act, 1999*[14] (including the PCB Regulations made thereunder),[15] Ontario's *Environmental Protection Act, 1990*[16] and the City of Toronto's Sewer Use By-Law.[17] Toronto Hydro has been targeting overhead transformers at risk of containing PCBs, which are all also past their useful life, and estimates there will be 223 overhead transformers that contain or are at-risk of containing PCBs remaining by the end of 2024.[18] Toronto Hydro intends to replace all of these units by the end of 2025.

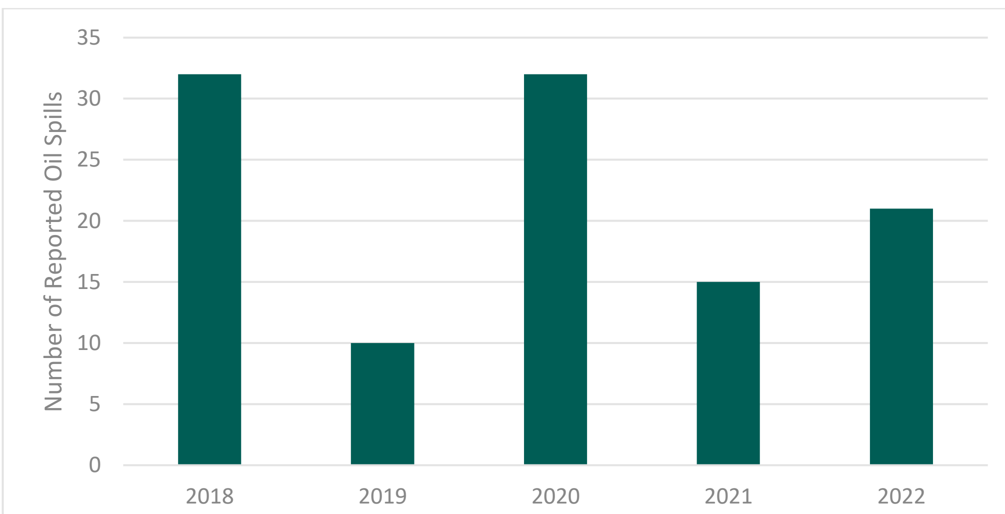


Figure 9: Number of Reported Pole-top Transformer Oil Spills

The utility investigated 547 failed overhead transformers between 2018 and 2022 to identify root causes of failure. The investigations found that 44 percent of the failed overhead transformers failed at or past the end of their useful life and that the number of failures increased with transformer age (see Figures 10 and 11). This is consistent with the expectation that transformers which are at or past

[14] *Supra* note 6.
[15] *Supra* note 5.
[16] *Supra* note 7.
[17] *Supra* note 8.
[18] Compared to approximately 6,400 at the end of 2017.

their useful life of 35 years are subject to an increased risk of failure. Most of the 4kV or 13.6kV system's transformers are also past their useful life, so by converting the system to 27.6kV these potentially failing transformers are removed from the population. In addition, Toronto Hydro, while conducting line patrols, identifies any transformers that show visual signs of deterioration for replacement.

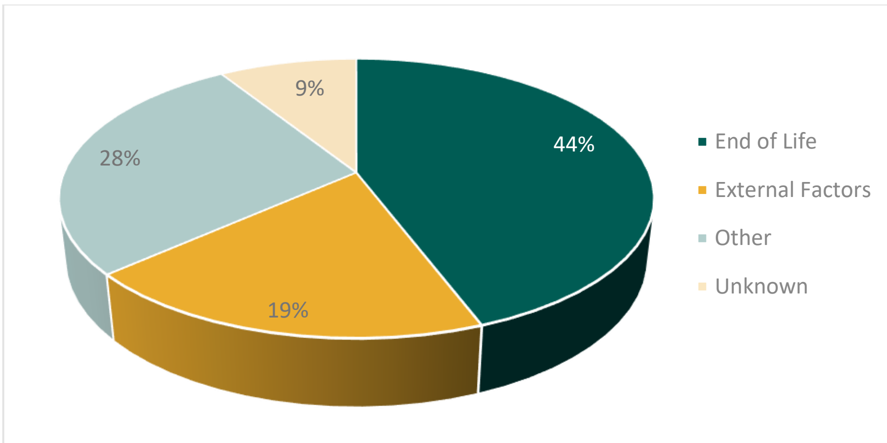


Figure 10: Root Cause Distribution for Failed Overhead Transformers from 2018-2022

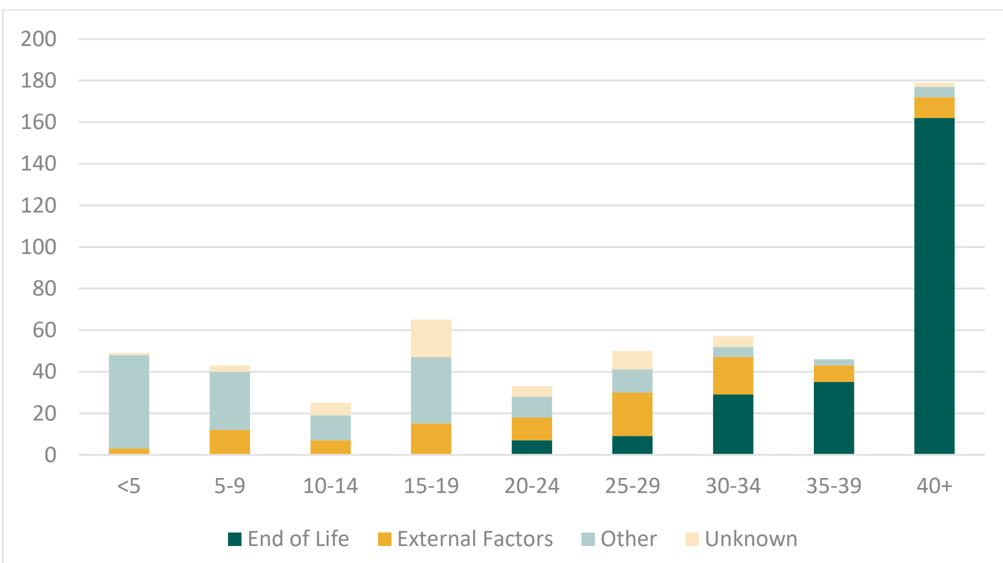


Figure 11: Age and Cause Distribution for Failed Overhead Transformers 2018-2022

Figure 12 shows the age distribution of overhead transformers in 2022 and in 2029 without investment. As of 2022, 2,245 transformers (8 percent) have surpassed their useful life of 35 years.

This is a significant improvement over 2017, when 14 percent were past useful life, and is expected to continue to improve due to the ongoing work to remove all the remaining overhead transformer at risk of containing PCBs. However, by 2029, without investment, the number of transformers past useful life will more than double to 4,747, and an additional 6,866 transformers will be within five years of end of life. Once all of the transformers at risk of containing PCBs have been removed, Toronto Hydro will shift away from spot replacements of transformers, and proactively replace them at a steadier pace through area rebuilds only. Using this approach, Toronto Hydro can ensure that the overhead transformers past useful life and associated reliability and environmental risks remains within a reasonable range over 2025-2029 and beyond, while taking advantage of the efficiencies (and other benefits such as reduced customer disruption) associated with area rebuild work.

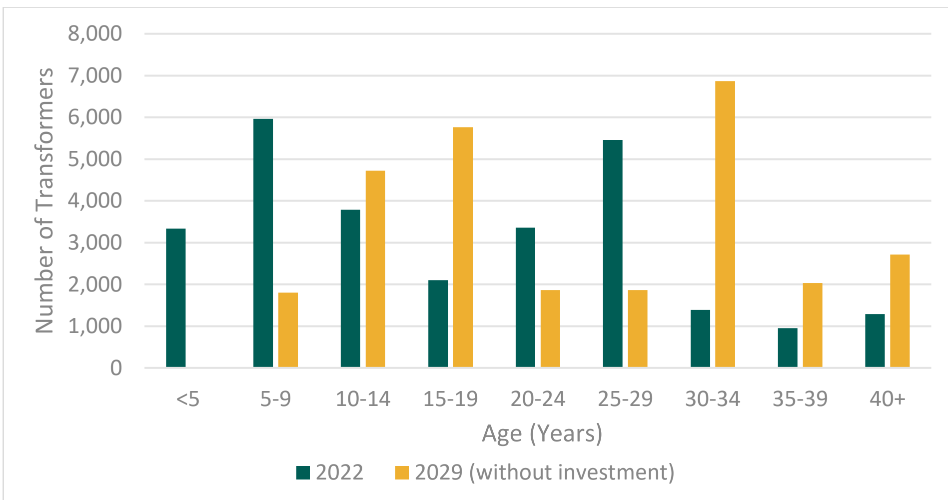


Figure 12: Age Distribution of Overhead Transformers in 2022 and 2029 (without investment)

Toronto Hydro will generally replace overhead transformers like-for-like unless undertaken as part of voltage conversion. However, one of the factors considered is whether the transformer in question is adequately satisfying design and policy requirements. In some cases, existing transformers are overloaded because they are oversupplying the total demand of secondary customers so they need to be upsized or a new transformer needs to be installed along with the one being replaced. Toronto Hydro also considers the City of Toronto's development pipeline[19] and future growth drivers, such as EV penetration when determining if upsizing or adding an additional transformer is required.

[19] Exhibit 2B, Section B2.2

2. Replacement of Poles and Accessories

Through the Overhead System Renewal segment, Toronto Hydro also replaces wood and concrete poles showing material deterioration as well as deteriorating or obsolete overhead accessories such as porcelain insulators and non-standard animal guards.

Toronto Hydro has approximately 108,988 wood poles and 49,059 concrete poles in service. Poles are exposed to environmental conditions that reduce pole strength, including internal rot and decay at the ground line, shell rot, and infestation. In most cases, pole failures can lead to significant public safety risks and prolonged service disruptions. Figures 13 and 14 show the contribution of poles and pole accessory related outages towards CI and CHI over 2018-2022. Poles contributed on average 6,627 customer interruptions and 4,700 customer hours of interruption per year over the last five years and these increase to 30,740 customers and 18,018 customer hours interrupted per year when also considering pole accessories. For the years 2019 and 2021, there were two lighting arrestor outages on the main trunk portion of a feeder that contributed to approximately 13,750 and 9,125 customers out of service respectively. Toronto Hydro has generally been successful in maintaining pole-related reliability and needs to continue proactively investing in pole renewal to manage pole failure risks.

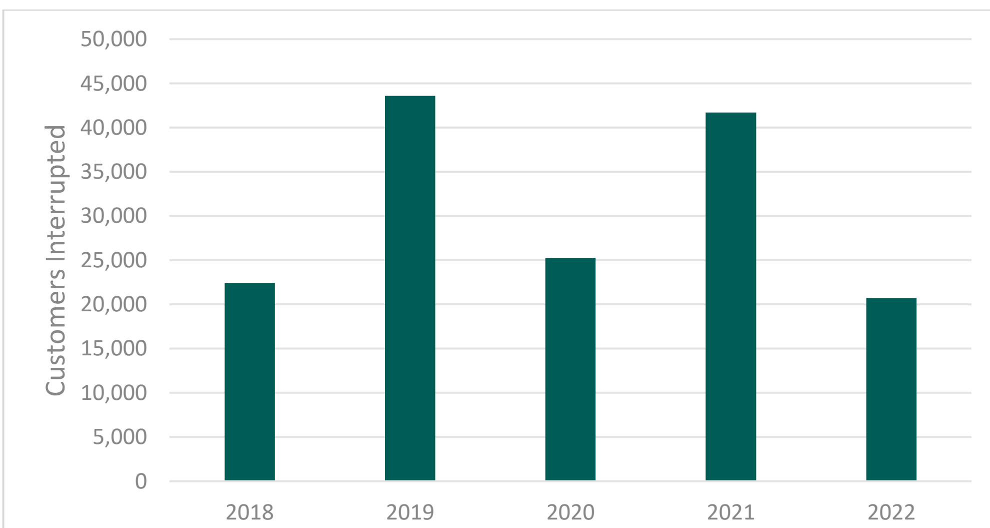


Figure 13: Customers Interrupted ("CI") for Poles and Pole Accessories

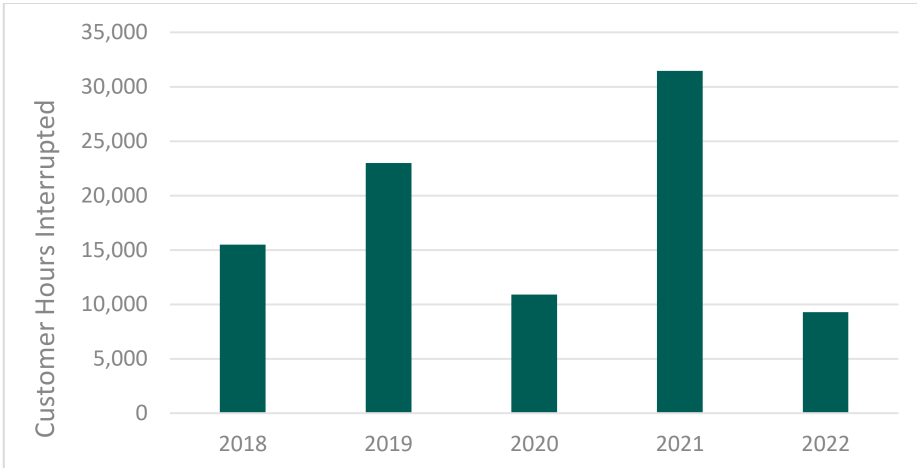


Figure 14: Customer Hours Interrupted ("CHI") for Poles and Pole Accessories

Poles with reduced strength present operational risks to Toronto Hydro crews, safety risks to the public, and reliability risks to the overhead distribution system. The combination of severe weather and poles with reduced strength can lead to catastrophic failure scenarios where one failure can trigger cascading failures on a pole line (i.e. drop of multiple poles and associated equipment, hardware and conductor to the ground). Figure 15 illustrates that, despite ongoing renewal, approximately 287 poles on average had to be replaced reactively per year between 2019 and 2022. Reactive work is variable by its nature and the number of reactive pole replacements can vary year-to-year due to a number of factors, including the number of condemned poles replaced reactively versus through proactive renewal projects and the condition of the poles. However, as discussed below, pole age and condition demographics indicate a continued need to invest in proactive pole renewal to avoid a sustained increase in the need for reactive replacements and related reliability and safety risks.

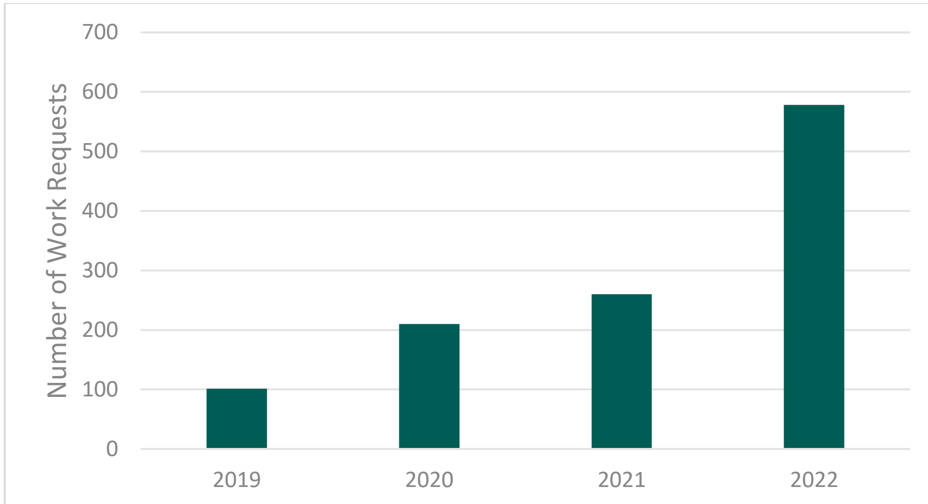


Figure 15: Reactive Work Requests for Pole replacement

In most cases, pole failures can lead to significant public safety risks and prolonged service disruptions. It is imperative that Toronto Hydro remains diligent and proactive in managing pole failure risks through pole replacements either through spot replacements or rebuilds.

Figures 16 and 17 show the age demographics of Toronto Hydro's wood and concrete poles (which have a typical useful life of 45 years and 55 years, respectively) as of 2022. A significant number of poles on Toronto Hydro's distribution system have already passed their useful life.

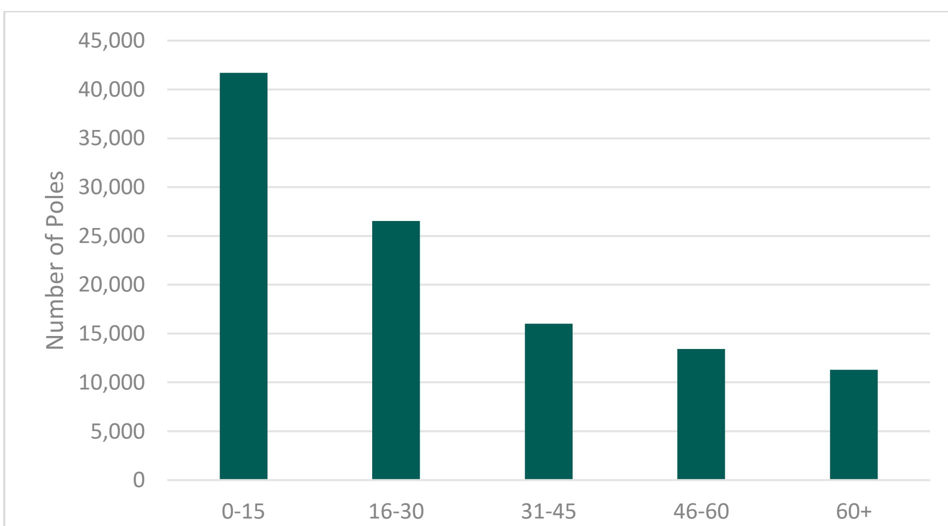


Figure 16: Age Distribution of Wood Poles (2022)

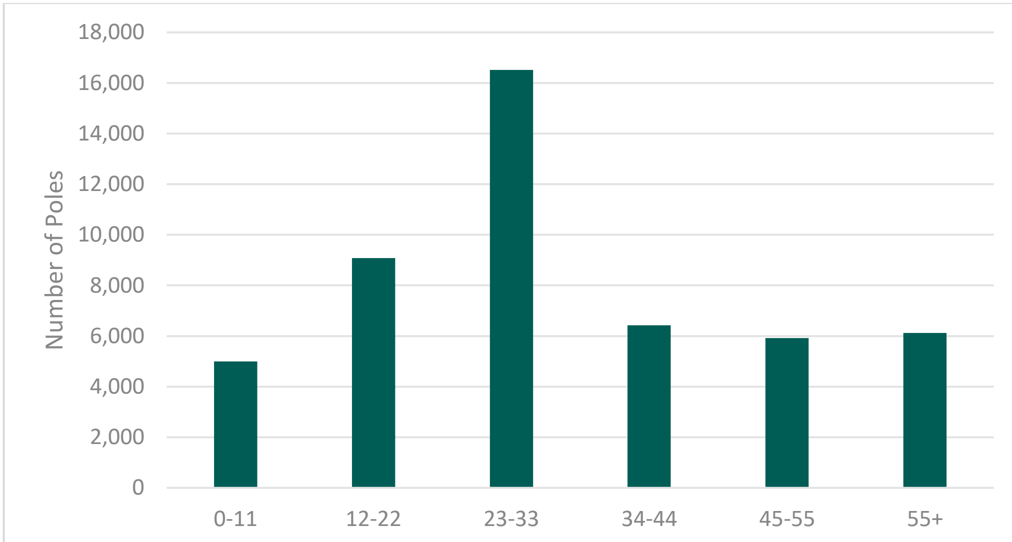


Figure 17: Age Distribution of Concrete Poles (2022)

Based solely on age, an estimated 23 percent or 24,958 wood poles and 13 percent or 6,505 concrete poles require immediate intervention to mitigate failure risk. However, Toronto Hydro plans to replace only aged poles in the worst condition.

The overall condition of poles is assessed through Toronto Hydro's pole inspection program.[20] The results of inspections from this program support Toronto Hydro's Asset Condition Assessment ("ACA") for wood poles. Toronto Hydro's current ACA methodology was first established in 2017; the methodology assigns a health score for condition (summarized into "Health Index (HI)" bands) to a pole based on predetermined criteria (as detailed in Exhibit 2B, Section D, Appendix A). Wood poles are vital assets to the overall overhead system and serve as an indication of overall distribution system health. The ACA results as of the end of 2022 indicate: approximately 9 percent of Toronto Hydro's wood poles (9,422) show signs of material deterioration and or are at end of serviceable life (classified as HI4 and HI5, respectively), and 20 percent of wood poles (21,015) show signs of moderate deterioration (classified as HI3), as shown in Figure 18. Toronto Hydro includes the System Health (Asset Condition) – Wood Poles measure in its 2020-2024 CIR Custom scorecard.[21] System Health is defined as the percentage of HI4 and HI5 poles over the entire pole population. Toronto Hydro's performance on this measure since 2018 is shown in Figure 19. While the Overhead System

[20] Exhibit 4, Tab 2, Schedule 1.
[21] EB-2018-0165, Exhibit 2B, Section C2.

Renewal segment is the biggest contributor to Toronto Hydro's performance on this metric, other programs, such as Area Conversions and Reactive and Corrective Capital,[22] also contribute.

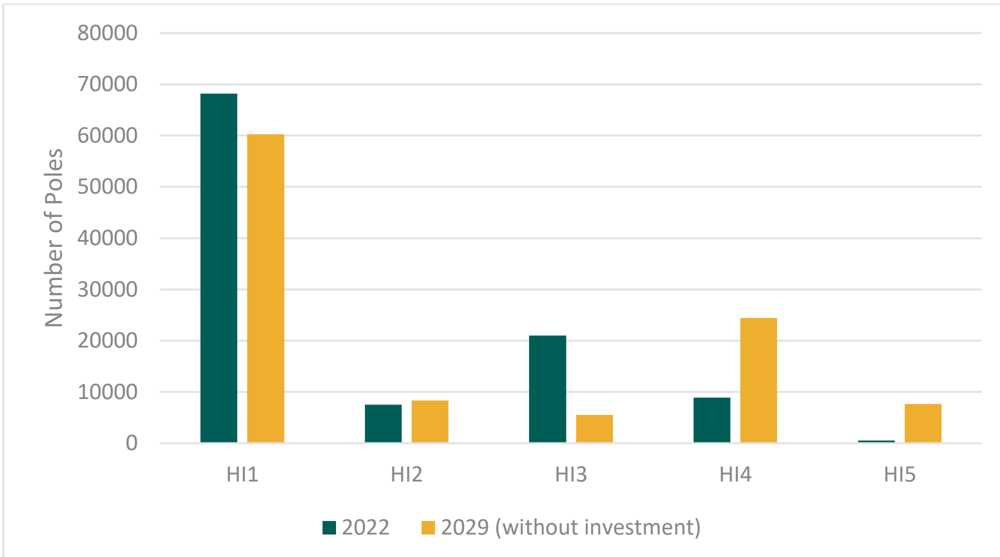


Figure 18: Condition of Wood Poles in 2022 and 2029 (without investment)

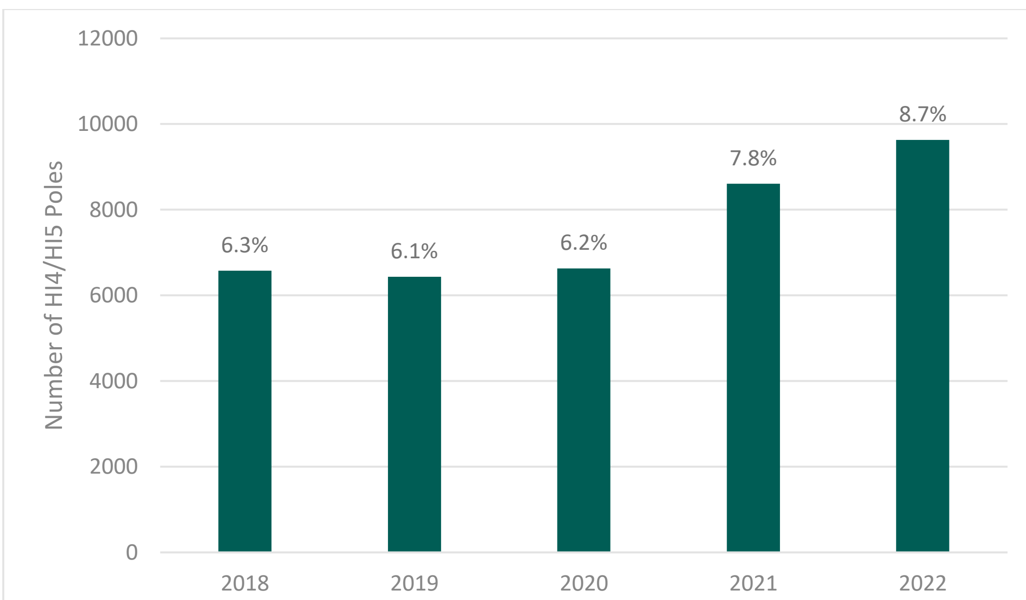


Figure 19: System Health (Asset Condition) – Wood Poles (2018-2022)

[22] Exhibit 2B, Section E6.1 and E6.7

The system health of wood poles has worsened over the past two years (as shown in Figure 19). This is attributed in part to the recent focus of capital renewal work on removing overhead transformers at risk of containing PCBs rather than rebuilds and conversions. Toronto Hydro is planning to replace 8,338 poles in HI4 and HI5 condition by the end of 2029 through overhead rebuild and conversion projects in areas with poor reliability and high concentrations of assets beyond useful life as well as through spot replacements.

In addition to replacing poles with material deterioration, the Overhead System Renewal segment replaces deteriorating and obsolete overhead accessories such as porcelain insulators, porcelain lightning arrestors, and non-standard animal guards. Pole accessories were the single largest contributor to forced outages on the overhead system in 2018-2022. Toronto Hydro's legacy insulators are predominantly porcelain, which has been used in insulation for switches, lightning arrestors, terminators, and line post insulators. Porcelain insulators possess high dielectric strength and good mechanical properties, including hardness and resistance to chemical erosion and thermal shock. However, it is susceptible to contamination build-up, and the accumulation of dirt and salt combined with moisture can lead to insulator tracking, flashover, cracks, insulator shattering and pole fires.

Table 5 shows the total number of pole fire incidents on Toronto Hydro's distribution system from 2015 to 2022. The number of pole fires from one year to the next can vary significantly as risks are related to weather conditions and the presence of contaminants (such as road salts and brines). The impact of a high number of pole fires in 2015 demonstrated how disruptive such incidents can be for the distribution system. The significant reduction in pole fire incidents after 2015 is due to the replacement of porcelain insulators with polymer insulators under a targeted replacement initiative in conjunction with increased insulator washing under the maintenance programs.[23] Toronto Hydro continues to perform regular insulator washing and replaces porcelain insulators as part of pole replacements to mitigate the risk of pole fire incidents.

[23] Exhibit 4, Tab 2, Schedule 1-4.

Table 5: Pole Fire Incidents

Year	Number of Pole Fire Incidents
2015	121
2016	39
2017	27
2018	8
2019	4
2020	17
2021	15
2022	28

3. Replacement of Overhead Switches

The last category of assets replaced through the Overhead System Renewal program is overhead switches. Overhead switches are a critical component of the distribution system that facilitate the isolation of feeder sections or equipment for maintenance during interruptions for load shifting and other operating requirements. They also allow workers to operate safely by isolating feeder sections and creating zones that are free of energized equipment. Toronto Hydro uses two types of switches in its overhead system: in-line disconnect switches and gang operated load break switches, each of which includes both manual load break switches and SCADA controlled switches. Currently there are 3,015 gang operated load switches and 4,425 in-line disconnect overhead switches in the overhead system.

Overhead switches are constantly exposed to harsh environmental conditions such as wind loading and salt spray. These switches can suffer either mechanical failure during operation or electrical failure via a flashover. Failed switches often lead to prolonged outages and pose significant safety risks to utility workers if an arc flash happens during switch failure. Gang operated and SCADA controlled switches were all inspected over 2020-2022 and, on average, 17 percent where found to have a defect such as corrosion. Figure 20 illustrates that 75 reactive work requests were initiated to address the defects found on switches in the overhead system between 2019 and 2022. Figures 21 and 22 show that, especially in recent years, overhead switches continue to contribute significantly to overhead customer outage frequency and duration. Gang Operated type switches, mostly SCADA-Mate, have contributed the most to reliability metrics since 2020 due to these types of switches operating on the trunk part of the feeder. When there is a failure on these types of switches, the impact is severe, affecting a large number of customers. On average over the past five years, overhead switches contributed to 37,070 customers interrupted and 20,264 customer hours of interruption per year.

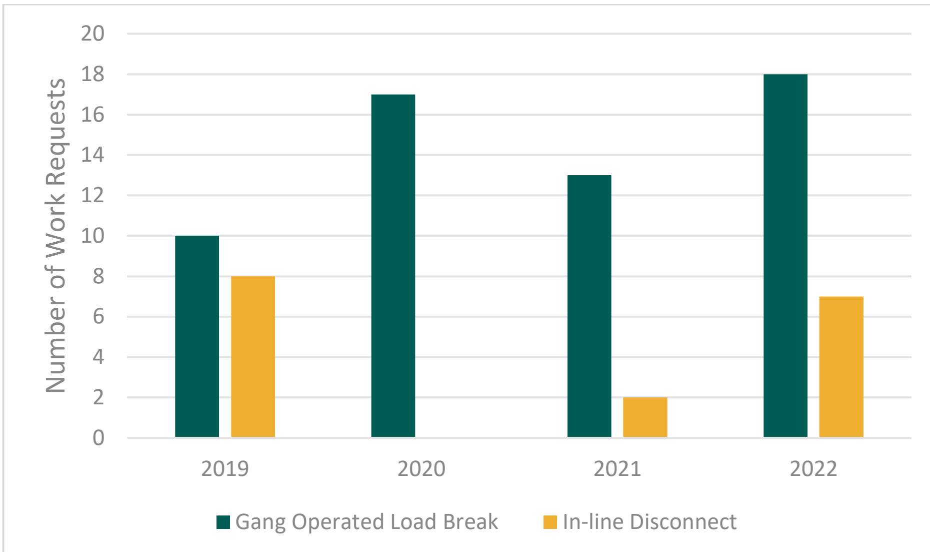


Figure 20: Reactive Work Requests for Overhead Switches

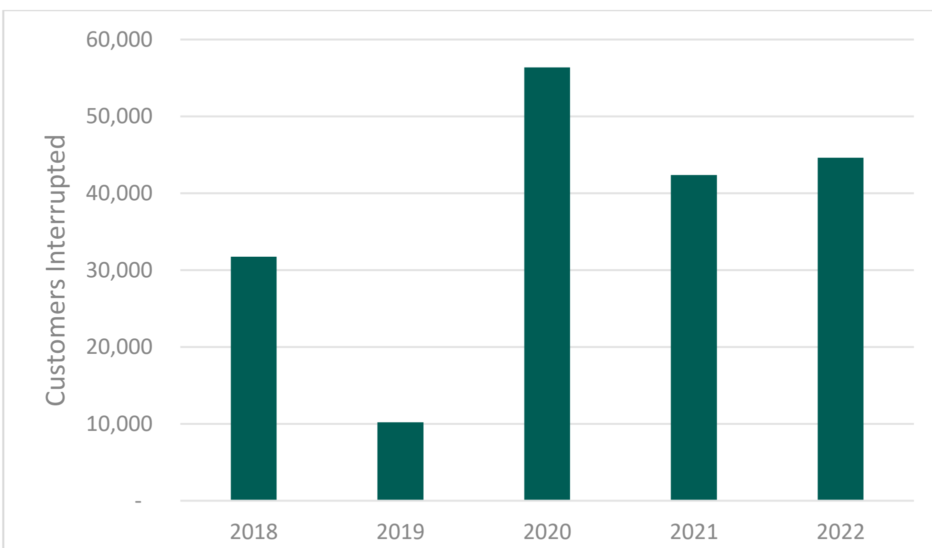


Figure 21: Customers Interrupted ("CI") for Overhead Switches

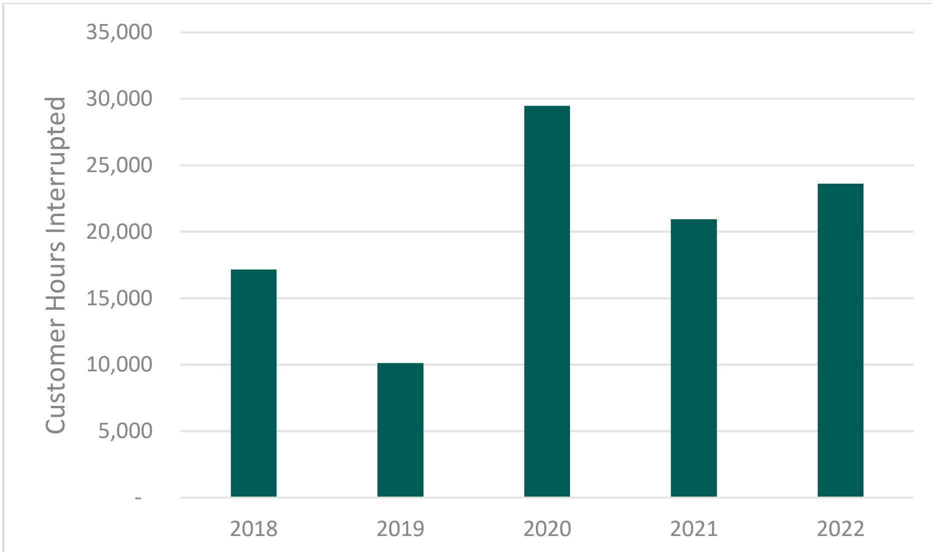


Figure 22: Customer Hours Interrupted ("CHI") for Overhead Switches

Gang operated load break overhead switches and in-line disconnect switches both have a useful life of 30 years.[24] Approximately 18 percent of gang operated switches and 33 percent of in-line disconnect switches have reached the end of their useful life as of 2022. Figure 23 shows the age demographics of Toronto Hydro's overhead switches in 2022. To support maintaining reliability risk, Toronto Hydro needs to continue its steady renewal of overhead switches to keep pace with the aging asset population and prevent an increase in failure rates. Figures 24 and 25 show the asset conditions of overhead gang operated and SCADA-Mate switches. While historically these types of switches have been in relatively good condition compared to the other overhead assets, the population of switches showing at least material deterioration (classified as HI4 and HI5) is expected to increase without proactive renewal.

[24] Previously Gang operated load break overhead switches had a useful life of 40 years while inline disconnect switches had a useful life of 45 years, but these have been reduced to 30 years based on review and insights gained from participation in the utility's latest Depreciation Study filed at EB-2023-0195, Exhibit 2A, Tab 2, Schedule 1, Appendix D

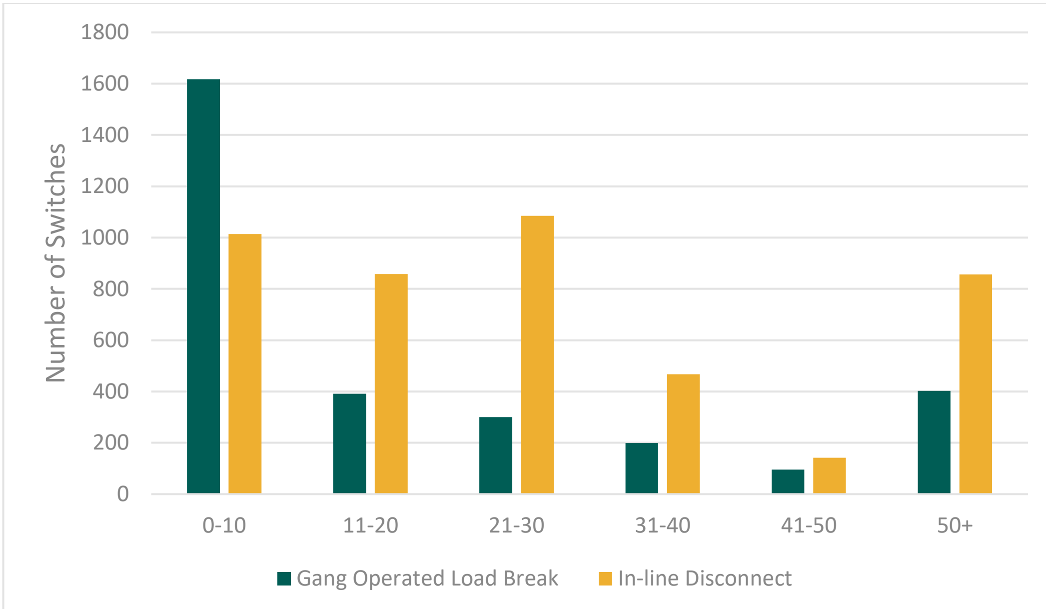


Figure 23: Overhead Switch Age Demographics (2022)

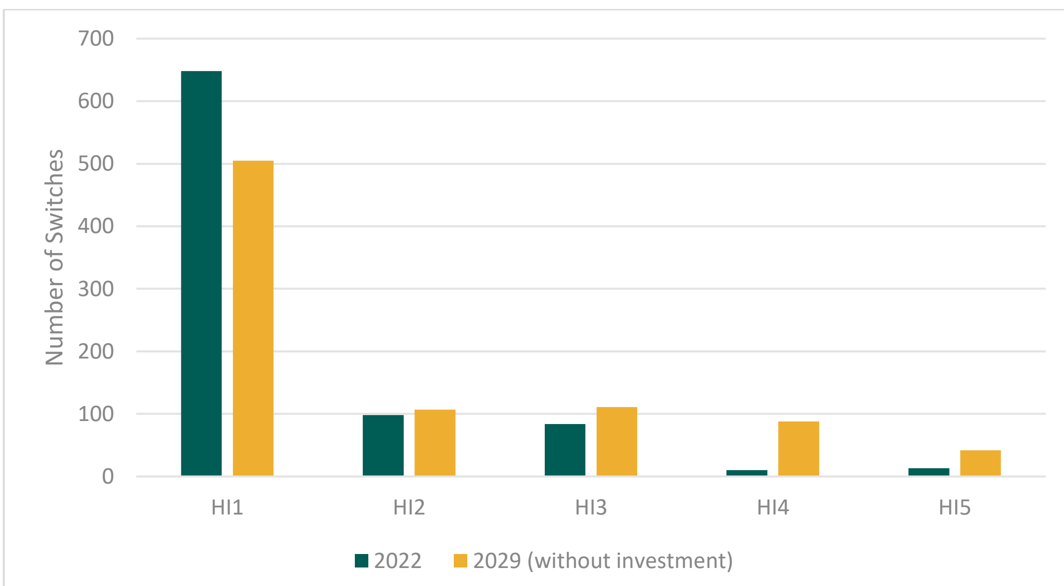


Figure 24: Condition of Overhead Gang Operated Load Break Switches in 2022 and 2029 (without investment).

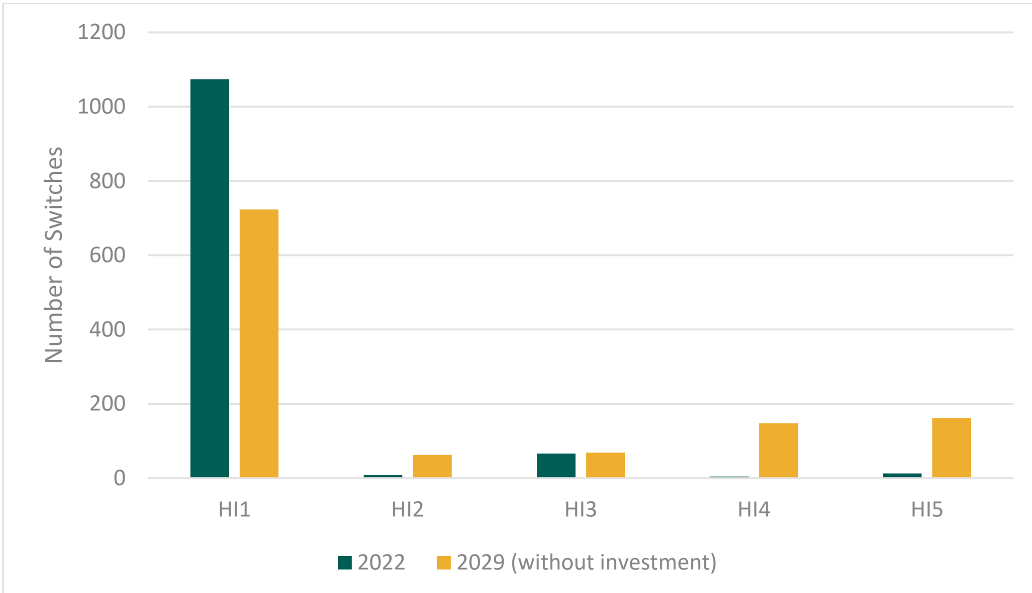


Figure 25: Condition of Overhead SCADA-Mate Switches in 2022 and 2029 (without investment).

E6.5.3.2 Overhead Infrastructure Resiliency

The objective of the Overhead Infrastructure Resiliency segment is to mitigate reliability and safety risks by targeting overhead infrastructure assets that are particularly vulnerable to outages and/or challenging to access due to their location or design. The Overhead Infrastructure Resiliency segment is directly responsive to customer priorities indicated in Phase 1 of Toronto Hydro's Customer Engagement by supporting reductions in the number of outages and restoration time in extreme weather.[25]

Targeted assets include overhead feeders with a history of outages due to weather-related events, tree and animal contacts, and foreign interference. They also include overhead infrastructure assets that are part of functionally obsolete designs, which are no longer aligned with Toronto Hydro's current planning and work practices, but which are not currently addressed through other capital programs. Toronto Hydro plans to mitigate safety and reliability risks associated with these feeders by relocating the existing overhead infrastructure to locations that are more accessible to Toronto Hydro crews and that lower the likelihood and impact of failure.

The primary activities in this segment are:

[25] *Supra* note 8.

1. Undergrounding of overhead assets that have a history of poor reliability (in the form of sustained or momentary outages) due to weather, tree, animal, or foreign interference related outages.
2. Relocation of overhead assets that are in areas with limited or difficult access, and along main arterial rail corridors.
3. Relocation of congested station egress assets with three or more circuits on the same pole.

This segment will mainly target the trunks of feeders as outages on trunks have a higher impact on customers. Trunks are the main sections of feeders exiting from the transformer station and laterals are the branches that come off the trunks and are protected by fuses. Figures 26 and 27 show the CI and customer minutes out ("CMO") impacts of outages due to adverse weather, tree contacts, and foreign interference over the last 5 years, broken down between trunks and laterals of feeders targeted in this segment.

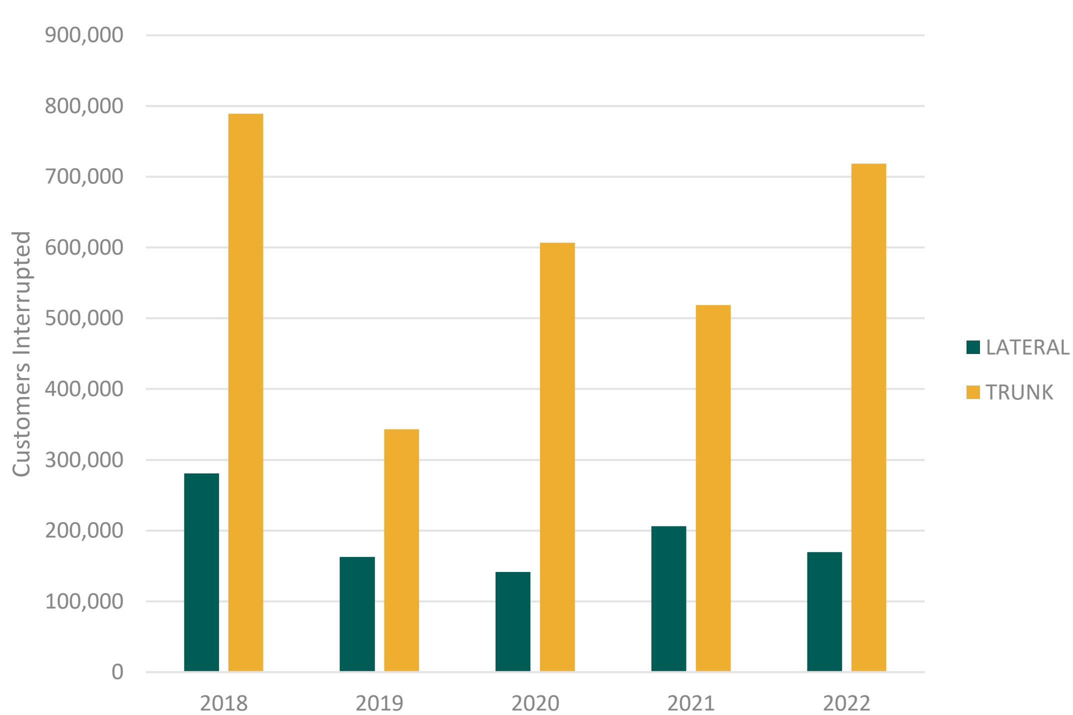


Figure 26: Total Customers Interrupted (CI) – Trunk Versus Lateral

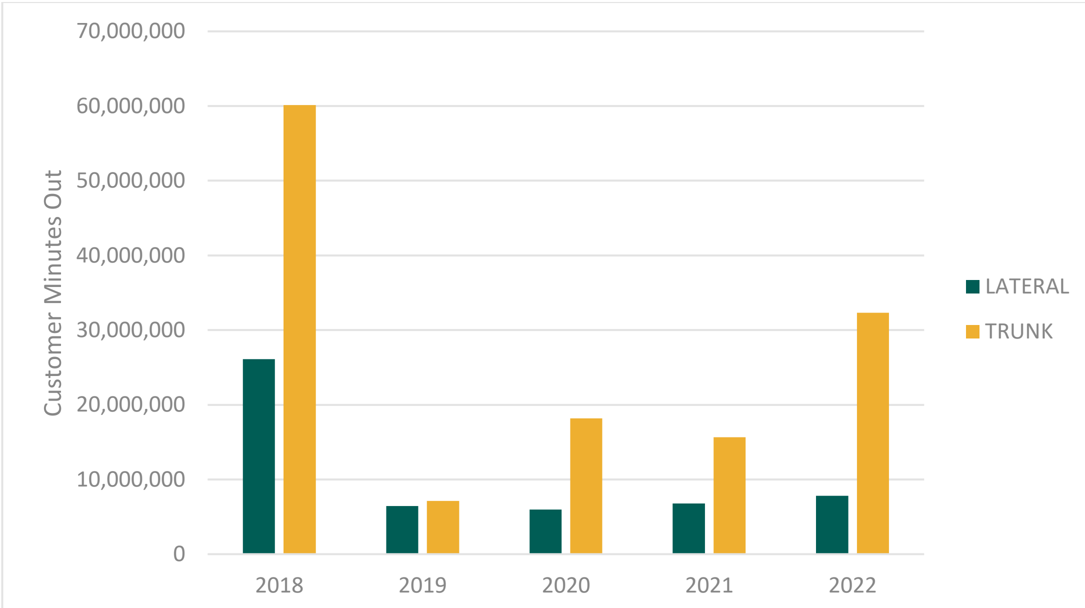


Figure 27: Total Customer Minutes Out – Trunk Versus Lateral

Additional details on the specific types of work and assets targeted in this program are provided below.

1. Overhead Feeders Based on Reliability History

The first category targeted through this segment is overhead feeders which are particularly susceptible to outages due to tree contacts, extreme/adverse environmental or weather factors, and foreign interference. Adverse weather factors include rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions. Adverse environmental factors refer to distribution assets being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, or fire.

Toronto Hydro has identified vulnerable overhead feeders based on the number and duration of outages related to these external factors, as shown in Figure 28 below. Toronto Hydro will target feeders with the greatest number of outages and highest customer hours interrupted as they are likely to benefit the most from being moved underground. By strategically undergrounding overhead sections of these feeders the utility will mitigate the frequency and impact of outages on affected customers, especially as adverse and extreme weather events become more frequent due to climate change.

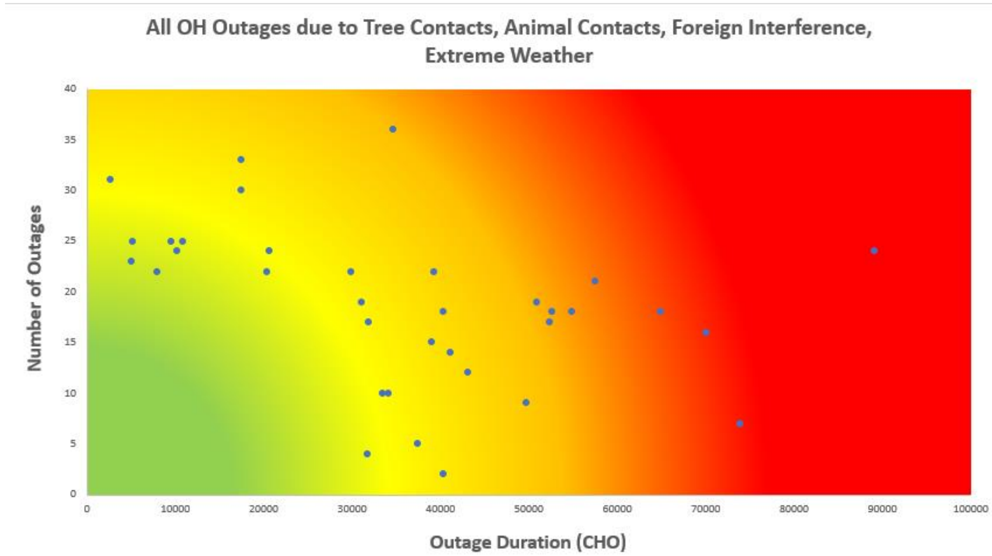


Figure 28: Overhead Outages due to Tree Contacts, Animal Contracts, Foreign Interference and Extreme Weather

2. Overhead Assets in Difficult to Access Locations

Overhead assets in certain parts of the city are located in areas that are difficult for Toronto Hydro employees to access for regular maintenance or for reactive repair or replacement. Figure 29 shows the locations of such assets. These locations can be especially vulnerable during major storm events such as heavy rainfall, floods, and ice storms and make restoration efforts following such events extremely challenging.

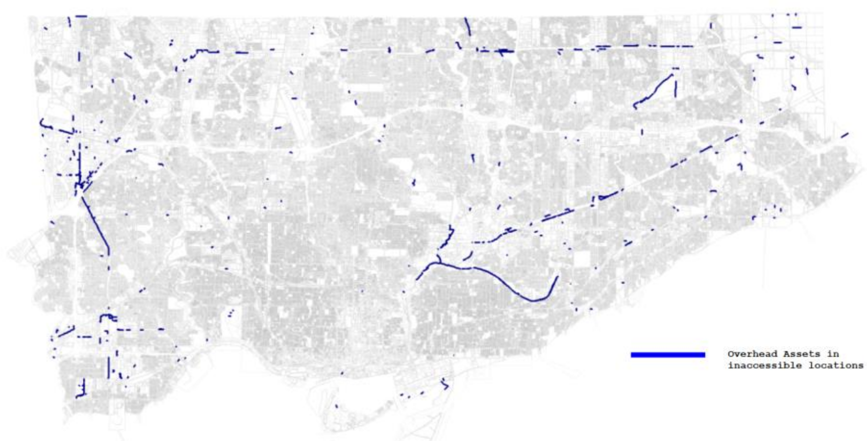


Figure 29: Overhead Assets in Inaccessible locations

Figures 30 and 31 show an example of difficult-to-reach assets. The red line in Figure 30 traces the path of three in-service feeders running through the Humber River in Etobicoke across Kipling Avenue, where access is limited. The poles carry one 27.6kV circuit feeder from Rexdale TS and two 4.16kV circuits from Watercliffe MS.

Figure 30: Difficult-to-Access Overhead Circuits on Humber River across Kipling Avenue

Figure 31: Difficult-to-Access Overhead Circuits on Humber River across Kipling Avenue

Another example is shown in Figures 32-33 where the two major circuits (traced in red) from Horner Transformer Station are on the Hydro One right of way ("ROW") and in a rail corridor. Access to these assets requires coordination with CN/CP Rail at all times, even in emergency conditions due to the safety requirement for a flag person from CN/CP authorities. Therefore, these circuits are deemed difficult to access and hence will be targeted for relocation and/or storm hardening.

Figure 32: Overhead Assets in Rail Corridor

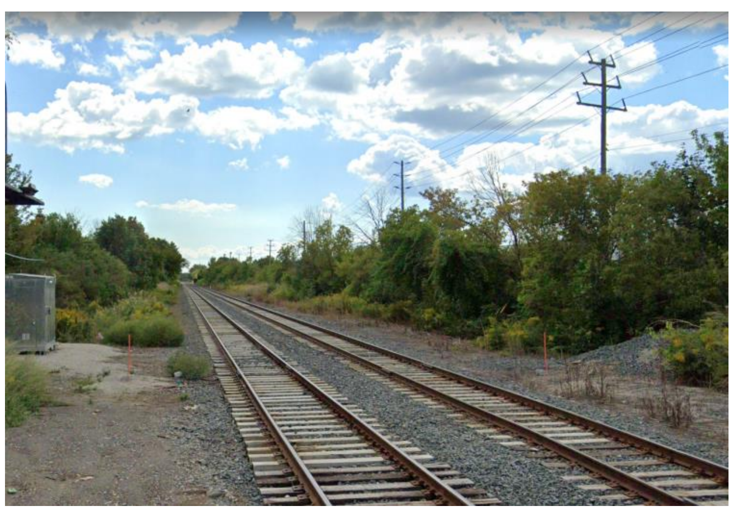


Figure 33: Overhead Assets in Rail Corridor

Toronto Hydro plans to reconfigure the feeders and relocate these assets away from the ravines and right of ways to improve accessibility for Toronto Hydro crew members and reduce vulnerability to outages in adverse weather conditions. This will reduce safety risks, such as slips, trips, or fall hazards due to uneven terrain and by enabling the use of bucket trucks instead of having to climb poles to perform certain activities. When climbing poles to work on energized lines, crews may not have bucket truck and equipment access, increasing the risk of coming into contact with live lines. The use of a bucket trucks is the most secure way for crews to reach the assets located on poles since the crews will be working on a stable and insulated aerial device. In general, the reconfiguration and relocation will reduce restoration times in the event of an outage.

Toronto Hydro will relocate these hard to access pole lines, including primary conductors, poles, insulators, transformers, switches and other associated overhead assets and replace them with new construction located in more accessible areas, e.g. overhead distribution on nearby roadways, underground distribution on boulevards, or ducts on bridges.

3. Congestion of Overhead Circuits Exiting from Transformer Stations

The initial section of a feeder exiting a transformer station extends to the first switching point or switchgear. This section is the ‘egress’ and it is a critical portion of the feeder because it carries the entire feeder load. Hence any failure or fault on an egress will result in an interruption to all of the customers on that feeder. If these egress sections are overhead, then they are also exposed to a wide variety of external factors that can cause interruptions, such as adverse weather, tree contacts, and foreign interference.

Toronto Hydro has determined that a single pole carrying three or more feeder egresses (three or more circuits) represents an unacceptably high level of risk to reliability due to the amount of load connected in a single physical location. Should a failure occur that impacts the pole line, three or more feeders could experience an outage, resulting in an unacceptably high number of customer interruptions. The risks are further exacerbated where the circuits on the same pole line are back ups to each other and hence a failure will result in a lengthy outage as restoration may not be possible immediately due to the coincident failure of the back-up feeders.

Through this segment, Toronto Hydro plans to reconfigure these assets such that there are no more than two feeders on a pole line. In some cases, this will involve replacing overhead egress with new underground tree-retardant cross-linked polyethylene (“TR-XLPE”) cable in concrete-encased conduit. The circuit will be underground from the circuit breaker to a point where it can return to overhead.

Figure 34 identifies the transformer stations with pole lines containing three or more circuits that Toronto Hydro will begin to target over the 2025-2029 period.

Figure 34: Transformer stations identified with 3 or more circuits

E6.5.4 Expenditure Plan

Table 6 provides the actual (2020-2021), Bridge (2022-2024) and Forecast (2025-2029) expenditures for the Overhead System Renewal program.

Table 6: Historical & Forecast Program Cost ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Overhead System Renewal	36.1	38.2	38.2	32.5	73.9	50.5	49.4	53.3	60.3	58.9
Overhead Infrastructure Resiliency	-	-	-	-	-	-	11.4	24.1	24.8	25.6
Total	36.1	38.2	38.2	32.5	73.9	50.5	60.8	77.4	85.2	84.5

E6.5.4.1 Overhead System Renewal Expenditure Plan

Table 7 below provides the actual, bridge, and forecast costs for the Overhead System Renewal segment. Toronto Hydro invested $112.6 million in the Overhead System Renewal segment between 2020 and 2022, and expects to invest another $106.3 million by the end of 2024. Tables 8 below shows the actual and forecast volumes of assets replaced over 2020-2024. The level of spending and overall unit volumes are both lower than forecast in the 2020-2024 DSP ($265.7 million and e.g. over 11,000 poles) as Toronto Hydro reduced the segment budget to support meeting overall capital funding limits[26] and faced supply chain challenges and other pressures impacting pacing and costs. The utility has been prioritizing replacement of overhead transformers with PCBs (i.e. through spot replacements) in order to eliminate them by 2025. However, supply chain challenges in acquiring sufficient transformers have reduced Toronto Hydro's ability to ramp up the pace of replacements as intended. The utility has been working diligently to mitigate the impacts of supply chain issues[27] and expects to increase the pacing towards the end of the rate period.

Table 7: Historical & Forecast Segment Cost ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Overhead System Renewal	36.1	38.2	38.2	32.5	73.9	50.5	49.4	53.3	60.3	58.9

Table 8: 2020 – 2024 Overhead Asset Replacement Volumes

Asset Class	Actual			Bridge		Total
	2020	2021	2022	2023	2024	
Poles	1,418	1,263	1,137	790	2,674	7,282
Transformers	401	584	579	215	1,892	3,671
OH Switches	185	290	71	43	114	703
Conductors* (km)	53.0	60.0	76.0	4.8	45.1	238.8

*Primary cables only

Other factors that can impact project timelines and costs include changes in scope requiring additional work, for example a collapsed duct needing to be repaired.

[26] Exhibit 2B, Section E4.
[27] Exhibit 4, Tab 2, Schedule 15.

Toronto Hydro forecasts spending $272.5 million on the Overhead System Renewal segment over the 2025-2029 period to achieve its goal to generally maintain asset condition and failure risk on the overhead system at current levels and eliminate the last of the overhead transformers at risk of containing PCBs. This includes the cost of replacing end-of-life assets and converting the 4.16 kV or 13.8 kV distribution system to standard 27.6 kV lines. In determining the appropriate pacing, Toronto Hydro carefully considered feedback from customers through the Customer Engagement process to ensure a balanced investment approach to the overhead system renewal portfolio: ensuring reasonable rates but also maintaining reliability. The 2025-2029 forecast expenditures are based on the historical unit cost trends of major asset classes and the forecast volumes of major overhead asset replacements for the same period, as shown in Table 9.

Table 9: 2025-2029 Volumes (Forecast): Overhead System Renewal

Asset Class	2025	2026	2027	2028	2029	Total
Poles	2,113	1,556	1,556	1,556	1,556	8,337
Transformers	1,232	907	911	908	889	4,847
OH Switches	123	91	91	104	102	511
Conductors* (km)	66	49	49	45	44	253

**Primary cables only*

The 2025-2029 forecast volumes are high level estimates based on a preliminary selection and scoping of areas targeted for complete rebuilds and spot replacements. Complete rebuilds include: replacing pole lines, overhead transformers and switches; upgrading associated overhead accessories; and re-stringing new conductor. Some of these areas are currently supplied by 4.16 kV and 13.8 kV systems, which will be converted to 27.6 kV through these projects. Once high-level project scopes are produced, Toronto Hydro performs field inspections to validate the scope of work, identify third party conflicts and refine estimates before final design is completed. Through this process, projects identified for renewal are subject to change. For instance, poorly performing feeders that demonstrate higher risks than originally anticipated may take priority.

The 2025-2029 program incorporates the three approaches described below.

- **Feeder Rebuild:** Rebuild of 27.6kV feeders in areas with poor reliability and high concentrations of assets in deteriorated condition that do not require voltage conversion.
- **Voltage Conversion Rebuild:** Voltage conversion of 4kV or 13.8kV to 27.6kV feeders in areas with poor reliability and high concentrations of HI4 and HI5 condition poles. Voltage

conversion requires that all poles, transformers, switches and conductor in each conversion area be replaced.

- **Spot Replacement**: Spot replacement of transformers containing (or at risk of containing) PCBs and the worst condition poles not targeted through the first two approaches.

Once Toronto Hydro has removed all transformers containing PCBs, it will shift towards a more rebuild-focused approach to overhead asset renewal, limiting spot replacements to only the worst condition poles not addressed elsewhere. The rebuild approach is intended to minimize supply disruptions to customers where possible. Reduced disruption to feeders translates into fewer outages for customers and improved project efficiencies. Another way Toronto Hydro maximizes efficiency and cost savings during project planning is by breaking large overhead rebuild projects into smaller phases for enhanced manageability and coordination, providing greater flexibility for scheduling and assigning resources. This approach also reduces the number of scheduled outages and disruptions that customers will experience.

In addition, Toronto Hydro will coordinate any voltage conversion overhead work with related Municipal Stations renewal work. This allows Toronto Hydro to eventually decommission Municipal Stations prior to any major renewal investments at those stations. Furthermore, the utility needs to strategically and systematically plan conversion work to ensure that the overall 4 kV or 13.8 kV system is still fully functional while the conversion is ongoing. There are additional cost savings and functional benefits from voltage conversions, including that the 27.6 kV distribution system transports more power over longer distances at lower losses (i.e. lower voltage drop at greater distances and improved power quality and distribution efficiency) than the existing 4.16 kV or 13.8 kV systems. This also results in fewer required Municipal Stations, leading to fewer assets to maintain, lower expenditures and greater reliability.

E6.5.4.2 Overhead Infrastructure Resiliency Expenditure Plan

Table 10 below provides the forecast costs for the Overhead Infrastructure Resiliency segment. There are no historical (2020-2022) or bridge (2023-2024) expenditures associated with this segment.

Table 10: Forecast Segment Cost ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Overhead Infrastructure Resiliency	-	-	-	-	-	-	11.4	24.1	24.8	25.6

Over 2025-2029, Toronto Hydro plans to spend $85.9 million to target overhead assets for relocation or undergrounding to mitigate reliability and safety risks and improve resilience. The focus of this segment is on very specific and particularly vulnerable sections of the overhead system only, such as those identified in Figure 35 below.

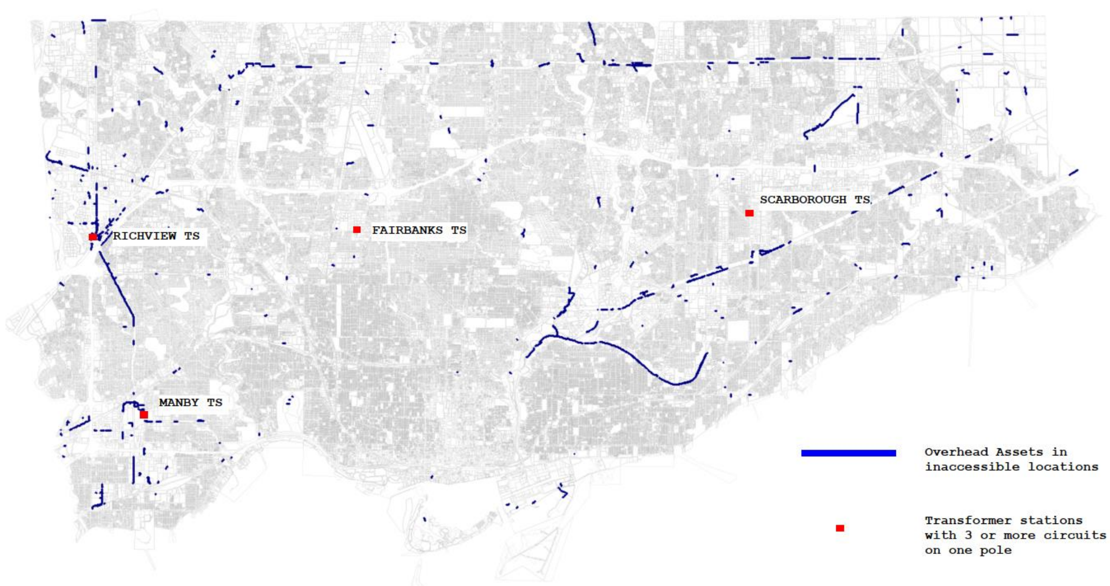


Figure 35: Potential Locations Targeted for Overhead Resiliency Investments

Toronto Hydro plans to target overhead areas which fall under the criteria described in Section E6.5.3.2: i) feeders with history of outages caused by external factors such as adverse weather; ii) feeders in hard to access locations; and iii) egress pole lines with three or more circuits. The utility will prioritize the highest risk areas based on the number of circuits, number and types of customers (e.g. whether includes key account customers), and potential impact to reliability.

The total number and timing of the areas targeted will depend on the specific locations and required scope and level of investment for projects selected (which have not yet been determined). Toronto Hydro has experience completing similar projects in the past, which it has used to inform the planned expenditures in this segment.

For example, in 2019-2020, the utility executed a project along Carlingview Drive between Dixon Road and Meteor Drive. The objective was the targeted undergrounding of two overhead 27.6kv circuits and two 13.8kv circuits, which were experiencing conductor galloping from the wind caused by airplanes landing at Pearson airport. This project undergrounded approximately 1 circuit-km of overhead feeders, installing 7 overhead switches, 5 padmount switches, 2 overhead transformers, approximately 16 km of cables (primary and secondary), 14 poles, and 9 cable chambers. The civil work cost $2.3 million and the electrical $3.5 million, which would be equivalent to approximately $3.1 million and $4.3 million in 2026.

E6.5.5 Options Analysis

E6.5.5.1 Options for Overhead System Renewal

Toronto Hydro considered the following options for the Overhead System Renewal segment. Under each of these options Toronto Hydro would seek to replace all remaining overhead transformers containing, or at risk of containing, PCBs by the end of 2025.

1. **Option 1: Limited rebuild/renewal of extremely poor reliability segments, voltage conversion of 36 Feeders and spot replacement of transformers, poles & switches in deteriorated condition, at or beyond their useful life**

Under this option, Toronto Hydro would prioritize and replace only overhead transformers, poles and switches in deteriorated condition that are at or past useful life. The utility would only rebuild or renew limited overhead assets (transformers, poles and switches) on the worst performing feeder segments and do voltage conversion of select areas that meet poor reliability criteria.

This option would provide minimal improvement in limited circumstances where only a limited number of assets on feeder segments that are in poor condition are replaced and eliminating these assets improves overall feeder performance. Under this option, the utility projects that the System

Health (percent of wood poles in HI4 or HI5) of the wood pole population would increase to 20.5 percent by 2029, even when considering the estimated impact of reactive replacements at a rate of 200 poles per year. The reduced pace of renewal in this option would expose the overhead distribution system to a higher risk of asset failure leading to deteriorating reliability and safety to utility workers and the public. As a result of this approach, Toronto Hydro would likely incur higher reactive repair costs, potentially with greater disruptions to the public and customers in the course of reactive repair work and could face a growing backlog of overhead assets at high risk of failure beyond 2029. Therefore, this option is not recommended.

2. **Option 2 (Selected Option): Proactive rebuild/renewal of priority areas exhibiting degradation or poor reliability, voltage conversion of 48 Feeders, and spot replacement of higher risk transformers (PCB only) and poles.**

This option proposes a rebuild or renewal of assets on feeders or geographical areas showing signs of degradation or progressively deteriorating reliability, and voltage conversion of functionally obsolete 4.16 kV or 13.8 kV primary voltage designs to 27.6 kV. Specifically, this option will include:

- Full rebuild of areas with poor reliability and a high volume of deteriorated assets beyond their useful life;
- Full rebuild and voltage conversion of 48 select feeders supplied by 4.16 kV or 13.8 kV primary voltage; with a history of poor reliability and a high concentration of assets beyond their useful life; and
- Like-for-like spot replacement of poles and associated overhead accessories showing material deterioration.

Toronto Hydro projects that under this option the System Health of the wood pole population would increase to 18.4 percent by 2029, assuming 200 HI4 and HI5 poles are replaced reactively each year (average over recent years). This is worse than the current system health, but an improvement over Option 1. In selecting this option, Toronto Hydro considered the need to strike a balance between maintaining acceptable safety and reliability on its overhead system, while providing electricity distribution services to customers at reasonable costs. This strategy is in line with Customer Engagement results, which indicate almost equal priority for rates and reliability. Through this option, Toronto Hydro would be best able to manage and mitigate the failure risk of overhead assets (i.e. by removing aged and unreliable assets to address deteriorating reliability), while improving efficiency and capacity of the system (through conversion of 4.16 kV feeders). Furthermore, this option will mitigate the potential accumulation of a large backlog of overhead assets at a high risk of failure and in need of replacement beyond 2029 (which would reduce reliability and increase costs for customers over the long term).

3. Option 3: Replace all assets in deteriorated condition (or beyond useful life) through 27.6kV rebuilds and convert 60 Feeders of 4.16 kV service areas to 27.6 kV

Under this option, Option 2 would be expanded in the following ways:

- Complete a higher number of targeted rebuilds, replacing approximately 12,000 poles, 7,000 transformers and 740 switches.
- Convert 60 4.16/13.8 kV feeders to 27.6 kV supply.

The above would provide additional reliability and other benefits such as improving system efficiency. This option would also ensure Toronto Hydro would have substantially less backlog of deteriorated and end of life assets by 2029 and less areas in the overhead system that are supplied by 4.16 kV. This is expected to reduce the number of failures on the overhead system, improve reliability and reduce the spending and resources required for reactive replacements. This option is projected to result in the System Health of the pole population reaching 15.0 percent by 2029. Additional voltage conversion would improve power quality and efficiency, reduce line losses, and accelerate decommissioning of certain municipal stations. However, the financial burden of this option increases dramatically at an estimated total cost of over $350 million.

E6.5.5.2 Options for Overhead Infrastructure Resiliency

1. Option 1: Do Nothing

Under this option, Toronto Hydro would not do any targeted undergrounding or relocation of overhead assets based on historical reliability, location, or design. The distribution system would continue to be prone to increased and prolonged outages on certain feeders due to overhead disturbances and accessibility issues for crews. The safety and operational issues discussed in Section E6.5.3.2, including challenges performing maintenance activities on inaccessible assets, would continue. In some cases, due to the hazards of accessing these locations, feeder outages will be deemed necessary to perform maintenance activities including tree trimming. Additionally, customers on affected feeders would continue to experience longer restoration times than those connected to standard and more accessible feeders.

2. Option 2: Like-for-Like Replacement

Like-for-like replacement would involve the replacement of assets characterized above at their existing locations. Under this option, the probability of failure related to asset age and condition would be reduced, but safety risks related to location would remain. In addition, limited accessibility would continue to impact power restoration times. The overall resiliency of the system would not improve and customers would continue to experience longer than necessary outages. In addition, for most of these cases, a like-for-like option may not be feasible due to the functional obsolescence and non-standard designs of these assets.

3. Option 3: Execute Overhead Infrastructure Resiliency Segment as Proposed

The Overhead Infrastructure Resiliency segment as proposed will directly address the source of specific vulnerabilities on the overhead system, including susceptibility to external factors, such as adverse weather and tree contacts, and functionally obsolete designs, which no longer align with Toronto Hydro's current planning and work practices. This will improve the resiliency of the system and result in improvements to safety and outage frequency and duration.

E6.5.6 Execution Risks & Mitigation

E6.5.6.1 Overhead System Renewal

Large overhead renewal projects can be complicated given that third parties could also be doing work in the same area, resulting in potential conflicts and leading to incremental costs and delays. To ensure effective coordination with the City and other utilities, Toronto Hydro participates in the Toronto Public Utilities Coordinating Committee forum.

Other execution risks associated with large overhead rebuild projects include:

- **Third Party Attachments**: Where third party attachments to Toronto Hydro assets will be affected as part of the project, the relevant owners must be contacted to explore alternative attachment options which may delay the execution timeline. To mitigate this risk, Toronto Hydro will engage owners of these third-party attachment assets as soon as possible to coordinate and plan the required transfer.
- **Permitting**: Delays in obtaining permits from applicable authorities (e.g. the City of Toronto, Ministry of Transportation, CN railways and Hydro One) may require extra design time. To mitigate this risk, additional design time will be built into the schedule to ensure the

necessary permits are obtained without material effect on project schedule. Also, Toronto Hydro will work closely with the City of Toronto on planned road work through meetings of the Public Utilities Coordinating Committee. If work planned by the City puts Program completion at risk, Toronto Hydro will negotiate with the City to coordinate a construction schedule that is acceptable to all parties involved.

- **Operational risks**: Load transfers can be restricted in certain months of the year due to high usage of electricity (e.g. during the summer months). Toronto Hydro will mitigate this risk by scheduling work to avoid periods of loading restrictions.
- **Resource availability**: Insufficient resources and materials can seriously impact project execution, resulting in delays or deferrals into future years. Most recently, there has been an increased risk to the supply chain for acquiring overhead transformers. To address this risk, engineering work plan meetings are held each year to ensure sufficient resources are procured and available to complete the approved projects for that year. When required, short interval control ("SIC") meetings are created for key resources with stakeholders across the organization to manage resources and forecast impact to work programs.
- **Conformance with standards:** Toronto Hydro designs and constructs new overhead rebuild projects in accordance with applicable standards and specifications that are intended to ensure public and employee safety. However, unique situations can sometimes arise to hinder design or construction in compliance with applicable standards. Identifying and making efforts to accommodate and address these issues during the planning and design stages can mitigate most of these risks. Toronto Hydro has established processes to address potential deviations from standards to ensure that the design and construction processes are not delayed and that any accepted deviations from standards do not impact the utility's ability to remain compliant with applicable requirements (including Ontario Regulation 22/04 - Electrical Distribution Safety).[28]

E6.5.6.2 Overhead Infrastructure Resiliency

Execution risks associated with overhead infrastructure resiliency projects include:

- **Third Party Coordination**: Road moratorium imposed by the City of Toronto (third party utilities) may affect areas where Toronto Hydro intends to relocate overhead assets

[28] Ontario Regulation 22/04 – Electrical Distribution Safety, under the *Electricity Act, 1998, S.O. 1998, c. 15, Schedule A.*

underground. To mitigate this risk, Toronto Hydro will coordinate with the City and identify potential conflicts and work around them or develop solutions for execution.

- **Access Issues**: Under this segment, Toronto Hydro will be targeting some assets specifically because they are located in areas with significant access challenges and associated crew safety issues, such as valleys and ravines. Toronto Hydro cannot use its usual equipment (e.g. bucket trucks) to execute this work and therefore will work to ensure that proper pre-job planning, training, and coordination is completed.
- **Operational Constraints and Project Coordination**: When replacing congested egress cables, the entire load of the egress section being worked on needs to be transferred to other feeders. Load transfers can be restricted in certain months of the year due to high usage of electricity, for example during the summer. Overloading feeders can cause equipment deterioration due to heat generated by losses that can result in deterioration of the insulation material, transformers and others. Toronto Hydro will mitigate this risk by scheduling the work where loading restrictions are low, coordinating with customers to avoid conflicts with their specific needs (e.g. school class times, facility production schedules).

E6.6 Stations Renewal

E6.6.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 175.4	**2025-2029 Cost ($M):** 282.7
Segments: Transformer Stations, Municipal Stations, Control and Monitoring, Battery and Ancillary Systems	
Trigger Driver: Failure Risk	
Outcomes: Operational Effectiveness - Reliability, Public Policy Responsiveness, Operational Effectiveness - Safety, Environment	

The Stations Renewal program (the "Program") manages station-level failure risk through the replacement of end-of-life and obsolete assets, and manages investments to modernize Toronto Hydro's substations. Customers have indicated that rates, reliability, and prudent modernization are their top priorities. Therefore, the proposed Program has been planned to meet two objectives: first, to maintain station reliability; and second, to replace the majority of Toronto Hydro's obsolete electromechanical relays with modern digital relays.

The failure of station assets can result in power outages for thousands of customers lasting several hours or more, and replacing station assets requires significant lead time. For example, TS Switchgear replacements require years to plan and complete. Hence, to meet customer expectations for reliability, Toronto Hydro proposes the proactive renewal of its station assets at a pacing set to maintain their reliability. This pacing is being proposed to balance the priorities of rates with station reliability. Toronto Hydro prioritizes station assets for proactive renewal based on their age, condition, performance, load served, and customers connected.

By the end of 2023, 43 percent of Toronto Hydro's station relays will be technically obsolete electromechanical relays, which do not permit event reporting, fault diagnostics, or power flow observability. Additionally, these obsolete relays have limited functionality to detect and discriminate between more complex faults that can lead to misoperation. The features of modern digital relays are needed to support Toronto Hydro's grid operability and evolution towards a smart grid infrastructure that integrates vehicle-to-grid, peak shaving, and increased distributed energy resource penetration.

The Program is grouped into the four segments summarized below and is a continuation of the station renewal activities described in Toronto Hydro's 2020-2024 Distribution System Plan.[1]

- **Transformer Stations ("TS"):** This segment involves the renewal of Toronto Hydro's TS switchgear, outdoor breakers, and outdoor switches located at TS. Replacing station assets that have deteriorated and are beyond their useful life allows Toronto Hydro to sustain reliability and mitigate crew exposure to safety hazards. TS assets supply commercial, industrial, and key account customers who are highly sensitive to power outages and power quality issues. During the 2025-2029 period, Toronto Hydro plans to replace three TS switchgear, complete four TS from the 2020-2024 period, 12 TS outdoor breakers, and 63 TS outdoor switches. Toronto Hydro also plans to refurbish one station building in preparation for switchgear replacements required over the 2030-2034 period. This segment is estimated to cost $134 million in total over the 2025-2029 period.
- **Municipal Stations ("MS"):** This segment involves the renewal of Toronto Hydro's switchgear and transformers located at MS and their primary supplies. Replacing these deteriorated and obsolete assets will allow Toronto Hydro to maintain reliability, improve worker safety, and sustain the system in the long term. The majority of Toronto Hydro's MS assets serve Toronto's suburban areas which consist largely of residential and general service customers. During the 2025-2029 period, Toronto Hydro plans to replace 12 MS switchgear, 15 power transformers, and one MS primary supply, for a total estimated cost of $70.3 million.
- **Control and Monitoring:** This segment involves the renewal and modernization of protection, control, monitoring, and communication assets at Toronto Hydro's TS and MS. Replacing these deteriorated and obsolete assets will allow Toronto Hydro to sustain reliability, and advance the modernization of Toronto Hydro's substations. During the 2025-2029 rate period, Toronto Hydro plans to renew 33 existing Remote Terminal Units ("RTUs") and replace 251 obsolete relays with modern digital relays, for a total estimated cost of $64.7 million.
- **Battery and Ancillary Systems:** This segment involves the renewal of DC battery and charger systems, station service transformers, and station AC service panels. This segment also installs new systems to mitigate the risk of flooding at targeted stations. During the 2025-2029 rate period, Toronto Hydro plans to replace 55 batteries, eight charger systems, replace

[1] EB-2018-0165, Exhibit 2B, Section E6.6.

three station service transformers, replace five station AC service panels, and install three sump pumps for a total estimated cost of $13.6 million. This work will allow Toronto Hydro to maintain the integrity of its station assets, maintaining reliability outcomes for Toronto Hydro customers.

Toronto Hydro plans to invest $282.7 million in the Stations Renewal Program in 2025-2029, which is a $107.3 million or 61 percent increase over the projected 2020-2024 spending in the Program. This increase is approximately equally split between an increased work volume and forecasted inflation. This level of investment is necessary to address an increasing population of end-of-life and poor condition station assets, address failure risks and trends identified over the 2020-2024 rate period, support Toronto Hydro's grid modernization investments, and prepare Toronto Hydro for continued success in the Program into the following period of 2030-2034.

E6.6.2 Outcomes and Measures

Table 2: Outcomes Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (SAIDI, SAIFI) by reducing the percentage of station assets in deteriorated condition and/or operating beyond their useful life (percentages vary by asset class)
	• Mitigates failure risks to tens of thousands of customers through renewal work
	    ○ 163,000 customers by replacing assets at and beyond useful life at Transformer Stations (e.g. switchgear, outdoor breakers, outdoor switches);
	    ○ 14,200 customers by replacing assets at and beyond useful life at Municipal Stations (e.g. switchgear, power transformers, primary supplies);
	    ○ 596,690 customers by renewing RTUs, Relays; and,
	    ○ 491,370 customers by renewing DC system and AC station service equipment

Public Policy Responsiveness	• Contributes to Toronto Hydro's Grid Modernization plan by replacing obsolete electromechanical relays with modern digital relays: ○ Accommodate increasingly sophisticated customer needs; ○ Help Toronto Hydro operate its system more efficiently to modernize the grid to allow for better observability and controllability; ○ Allow for fault recording; ○ Provide relay diagnostics for easier maintenance; ○ Better fault coordination; and, ○ Help provide increased value to customers • Increasing the population of station digital relays to 90 percent in 2029
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's public and worker safety performance, as measured by the Serious Electrical Incident Index and Total Recordable Injury Frequency by: increasing the population of arc-resistant switchgear, and decreasing the population of oil-filled TS outdoor breakers
Environment	• Contributes to Toronto Hydro's environmental stewardship by reducing the number of station assets containing (or at-risk of containing) degraded oil

E6.6.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Functional Obsolescence, Public Policy

The Stations Renewal Program addresses failure risk and obsolescence issues associated with Toronto Hydro's critical station assets. A large portion of Toronto Hydro's station assets are operating beyond their typical useful lives and are subject to an increased risk of failure due to their age and condition. Station asset failures have large impacts on system reliability due to the large number of customers served by each station. Necessary repairs are often complex and take significant time to complete.

Like distribution line assets, prudent management of station assets is achieved by monitoring asset demographics and condition. However, management strategies that use run-to-fail or just-in-time asset replacement are generally unacceptable for station assets due to the impacts of failed assets on customers.

In addition to their increasing failure risk, many older assets use technology that has become obsolete due to advancements, emerging industry trends, and evolving best practices related to safety, customer needs, and functionality. Replacing obsolete assets allows Toronto Hydro to meet public policy outcomes, accommodate increasingly sophisticated customer needs (e.g. vehicle-to-grid, peak shaving, and distributed energy resources applications) and operate the utility's system more efficiently.

E6.6.3.1 Transformer Stations ("TS")

Toronto Hydro's TS supply power to all customer classes. Major TS assets include TS switchgear, TS outdoor breakers, and TS outdoor switches. A large portion of these assets are operating beyond their useful life and are at a heightened risk of failure. Toronto Hydro uses a risk-based approach to identify the highest priority TS assets for replacement. The utility's asset management objective is to cost-effectively sustain current levels of reliability and prudently mitigate crew exposure to safety hazards.

1. TS Switchgear

As shown in Table 4 below, about a third of Toronto Hydro's TS switchgear will be operating past its useful life by the end of 2024. Many of these assets are non arc-resistant and have other obsolete design features that increase safety risks for crews and the risk of collateral asset damage in the event of switchgear failure.

Table 4: Transformer Station Switchgear Demographics at end of 2024

Switchgear Construction	# of Assets	% of Assets Past Useful Life	Other Demographic Information	
			% of Non-Arc Resistant Switchgear	% of Switchgear with Obsolete Breakers
Metalclad	45	40%	73%	7%
Brick Structure	3	100%	100%	100%
GIS	5	0%	0%	0%
Total	53	34%	68%	11%

Toronto Hydro uses asset condition, age, and operational feedback to identify and prioritize the renewal of its switchgear assets. Switchgear are complex assets that include several different parts. Each part has its own failure mode and useful life, which are often less than the 50 years attributed to the switchgear as a whole. Toronto Hydro performs reactive repair and maintenance on individual switchgear parts. This reactive approach becomes less prudent as components that cannot easily be replaced age and deteriorate. Examples include bus bars, bus insulators, and miscellaneous control wiring.

Toronto Hydro assesses the condition of switchgear assets using infrared hotspot scanning, and cable termination, connection, and cleanliness qualitative (visual) assessments. Major components such as breakers are also individually assessed. Toronto Hydro previously used these measurements (excluding the breaker condition assessments) to derive a single health index measurement ("HI") for switchgear. However, the HI reflected a limited number of measurements and made it difficult to balance different indicators. As a result, Toronto Hydro now assesses risk using switchgear age, breaker condition, and operational feedback to evaluate these asset components on an asset-by-asset basis. The current age demographics of Toronto Hydro's TS switchgear units are shown in Figure 1 below.

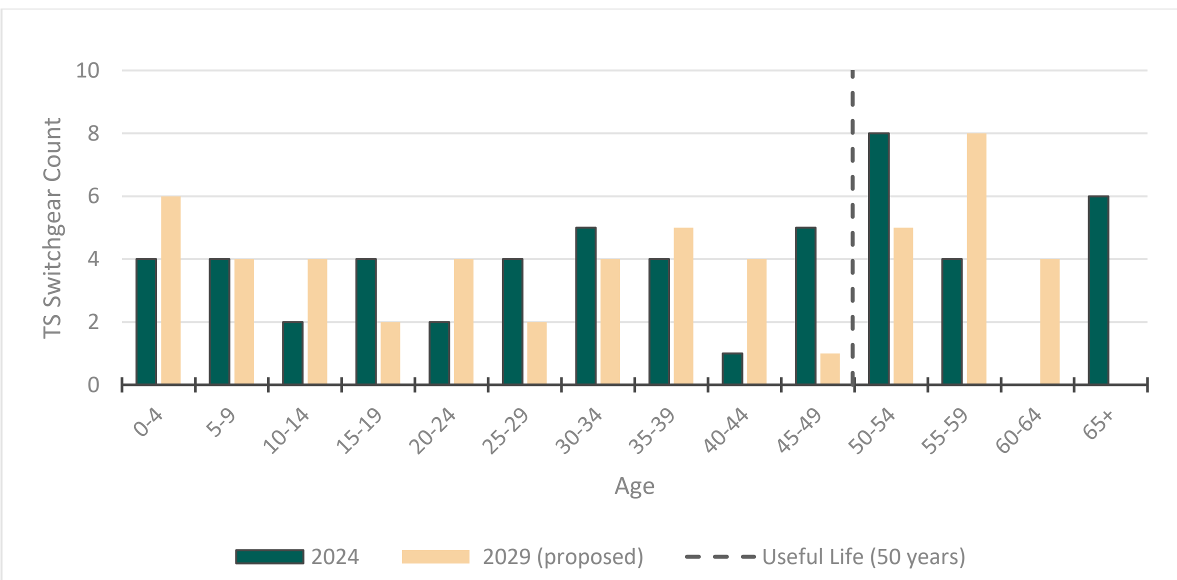


Figure 1: TS Switchgear Age Demographics

As indicated in Figure 1 above, Toronto Hydro anticipates having 18 TS switchgear units operating at or beyond their useful life expectancy by 2024 and 17 units by 2029. Toronto Hydro's condition assessment for all breakers contained within its TS switchgear population is shown in Figure 2 below. A significant proportion of Toronto Hydro's breakers with moderate deterioration or worse are air-blast breakers. These are the oldest breakers in use. The technology is obsolete and it is difficult to obtain parts for maintenance. These breakers are found in 11 of the switchgear units operating beyond their useful life.

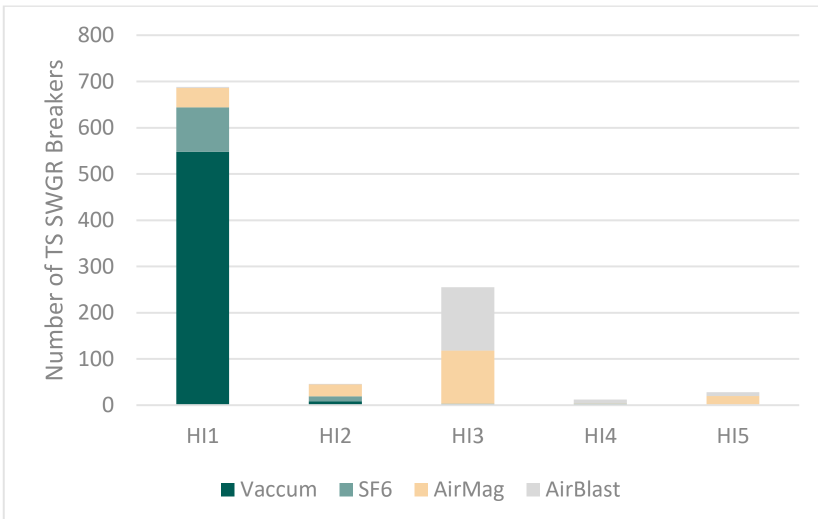


Figure 2: TS Switchgear Breaker Condition by Type as of 2022

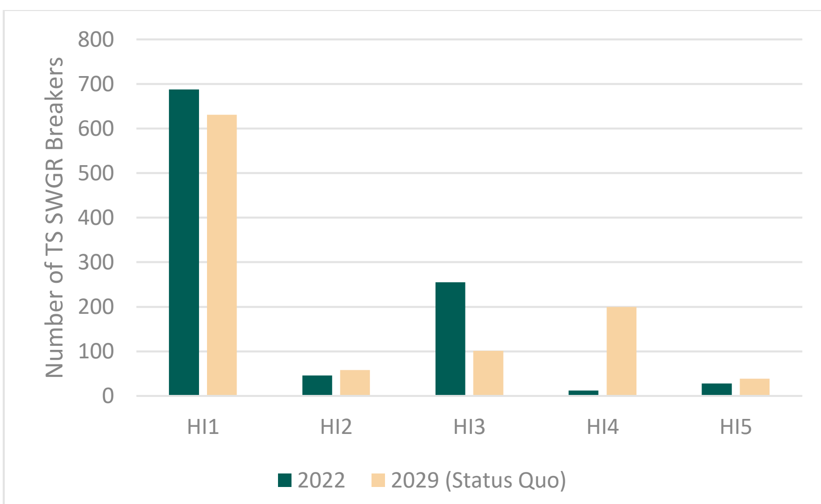


Figure 3: TS Switchgear Breaker Condition Aggregate as of 2022 and in 2029 Without Investment

Switchgear failure has a severe impact on distribution system operations. As one example, a recent failure of a switchgear breaker resulted in a power interruption for 13,152 customers and 10.5 MVA of the bus load. The average affected customer was without power for two hours and it took two and a half hours for the last customers' power to be restored following the failure. A photo of the failed breaker is shown in Figure 4 below. As shown in the photos, visual condition assessment may not always be effective because components are not accessible for the level of inspection required to detect measurable signs of impending failure. This is particularly true for some metalclad switchgears that require a complete switchgear outage to enable a thorough assessment of their condition, which is not possible without significant customer outages. The newer buses address this issue by allowing for efficient load transfers.

Figure 4: Failed Switchgear Air Blast breaker and damaged arcing contacts

Figure 5 below shows the number of bus outages due to failure of TS switchgear components over the last ten years. These include a breaker's failure to open on fault, a failed CT and a failed bus insulator. Investments in asset renewals to maintain TS switchgear components in healthy operational condition are essential for Toronto Hydro to provide its customers with reliable service.

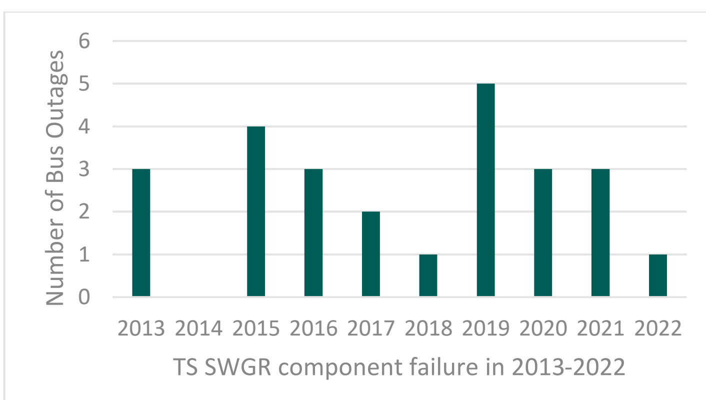


Figure 5: Bus outage caused due to SWGR component failure in 2013-2022

Toronto Hydro's average TS switchgear supplies 37 MVA of load – more than the failure case highlighted above – and its heaviest loaded unit serves 63 MVA of peak load. As shown in Figure 6 below, these assets primarily serve Toronto's downtown and adjacent areas, which include Toronto's financial district, entertainment district, university district, and some of the city's densest residential communities.

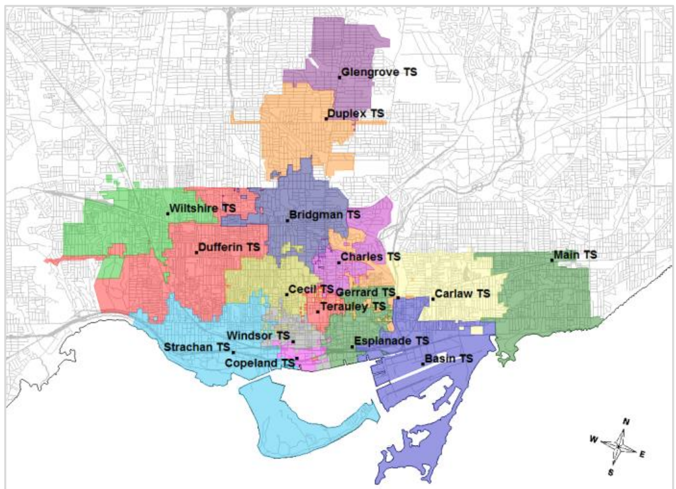


Figure 6: Location of TS containing Toronto Hydro-Owned Switchgear (excluding Cavanagh TS in North Scarborough)

Toronto Hydro proposes to replace the five TS switchgear units identified in Table 5 below during the 2025-2029 period. All of the units proposed for replacement are beyond their 50-year useful life expectancy and feature obsolete circuit breakers contained within non-arc-resistant enclosures. Condition assessments performed during breaker maintenance show that all of the breakers in the switchgear units proposed for replacement suffer from HI4-material deterioration. This is an older air blast type installed in the 1950s that is functionally obsolete. Breakers are used to determine the condition of a switchgear because they are the "moving parts" inside of switchgear and are indicative of a switchgear unit's overall health.

Table 5: TS Switchgear Proposed for Replacement

Station	ID	Enclosure	Breaker Type	2022 Condition Assessment (for Breakers)	Replacement Year
Danforth MS	*A1-2DA*	Brick	Air Blast	Material Deterioration	2029
Bridgman TS	*A7-8H*	Brick	Air blast	Material Deterioration	2029
Windsor TS	*A3-4WR*	Metalclad	Air blast	Material Deterioration	2029

Station	ID	Enclosure	Breaker Type	2022 Condition Assessment (for Breakers)	Replacement Year
Bridgman TS	*A1-2B*	Metalclad	Air blast	Material Deterioration	2029 (building renovation by Hydro One)

As shown in Table 6 below, with these replacements and investments, by the end of 2029 there will be a decrease in non-arc resistant switchgear units from 68 to 53 percent and a decrease in switchgear units with obsolete breakers from and 11 to 2 percent compared to 2024.

Table 6: Transformer Station Switchgear Demographics at End of 2029 with Investment

Switchgear Construction	# of Assets	% of Assets Past Useful Life	Other Demographic Information	
			% of Non-Arc Resistant Switchgear	% of Switchgear with Obsolete Breakers
Metalclad	48	35%	58%	2%
Brick Structure	0	0%	0%	0%
GIS	5	0%	0%	0%
Total	**53**	**32%**	**53%**	**2%**

Figure 7 below shows the volume of customers and quantity of load that will benefit from Toronto Hydro's proposed replacement plan.

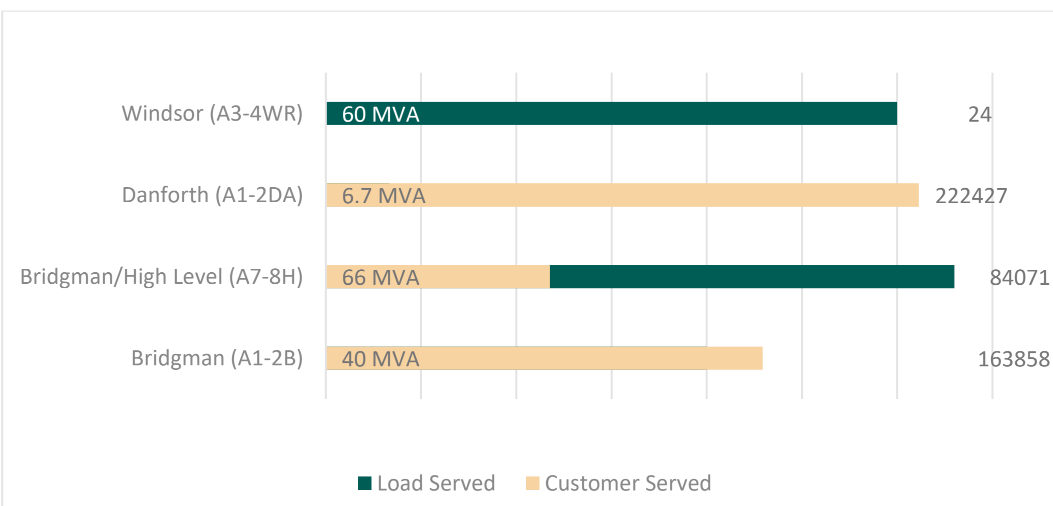


Figure 7: Customer Impact of Switchgear Failure - TS Switchgear Proposed for Replacement

2. TS Outdoor Breakers

As shown in Table 7 below, 13 percent of Toronto Hydro's TS outdoor circuit breakers will be operating past their 45-year useful life by the end of 2024. These breakers (i.e. the KSO oil circuit breakers) are based on obsolete technology and may contain degraded oil, which would increase the safety risk for crews, the risk of collateral damage to other assets, and the risk of environmental damage if a breaker failure occurs. As indicated in Table 7, 100 percent of Toronto Hydro's KSO oil-based circuit breakers will be past their useful life of 45 years by the end of 2024.

Table 7: TS Outdoor Breakers Demographics at the end of 2024

Outdoor Breaker Technology	# of Assets	% of Assets Past Useful Life
KSO Oil Circuit Breaker	12	100%
SF6 Circuit Breaker	24	0%
Vacuum Circuit Breaker	56	0%
Total	92	13%

Figure 8 below compares the condition of the utility's TS outdoor breakers as of 2022 with the condition of the breakers in 2029, in a scenario without investment.

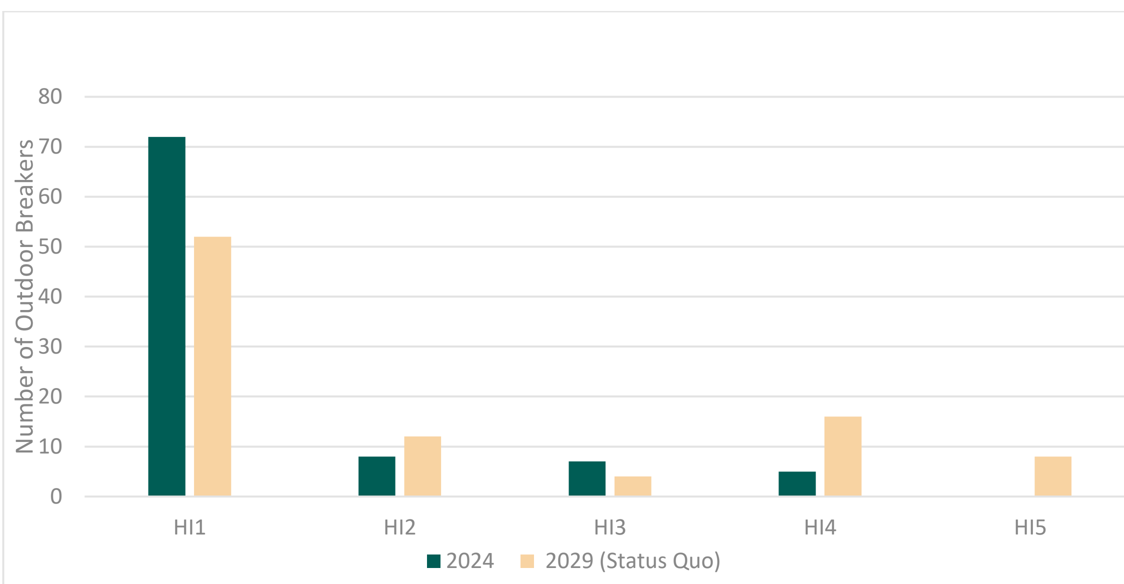


Figure 8: TS Outdoor Breaker Condition as of 2022 and in 2029 without Investment

As of the end of 2022,

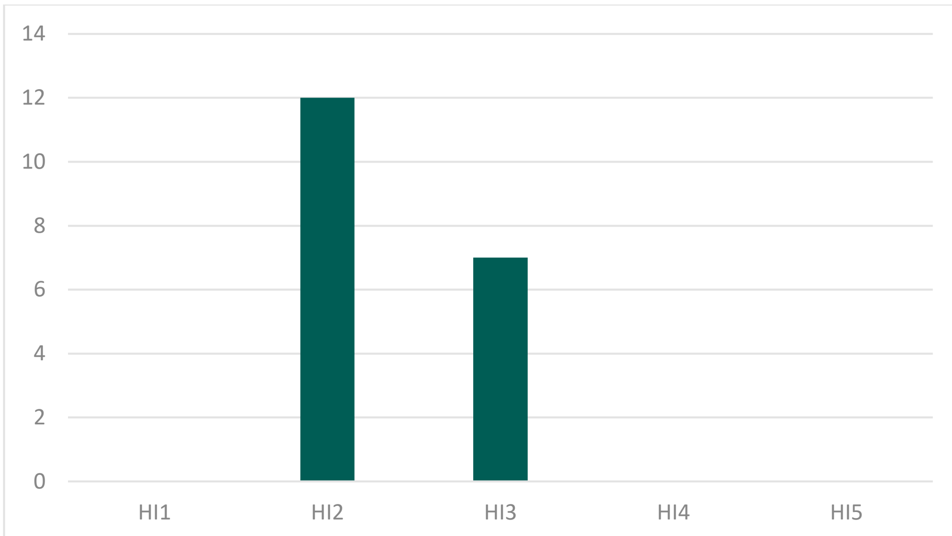


Figure 9 below illustrates the condition of these circuit breakers at the end of 2022 (including the units planned to be replaced in 2023 and 2024).

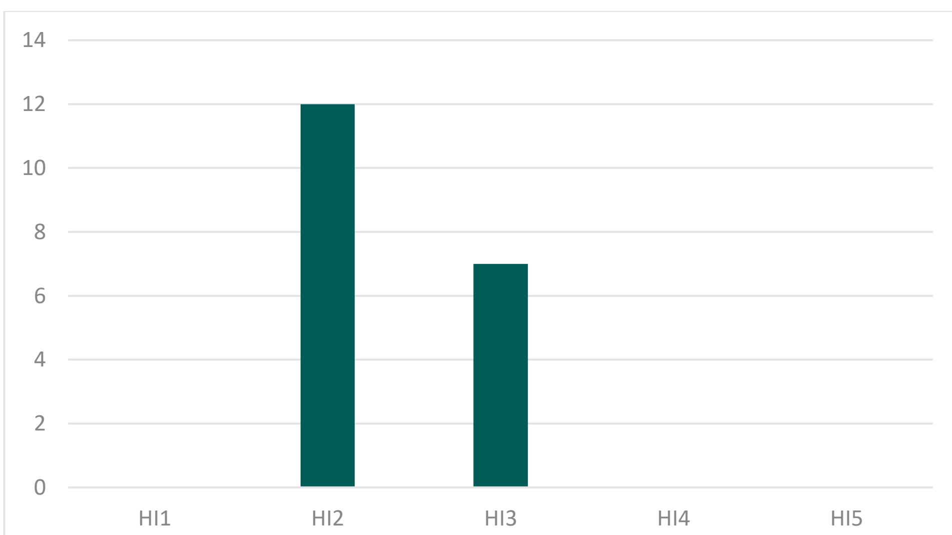


Figure 9: Condition Assessment for KSO Oil Circuit Breakers as of the end of 2022

Toronto Hydro plans to replace all the oil KSO breakers with vacuum breakers by the end of 2029. In order to minimize the outage time for each cell, the relays will be replaced together with the KSO breakers unless cell relays have already been reactively replaced prior.

These investments would enable Toronto Hydro to improve its ability to accommodate new customer connections, including renewable generation or energy storage systems. As such, this work will provide customers with increased reliability and flexibility and will eliminate some of the system's biggest safety and environmental risks.

The failure risk of KSO circuit breakers is high and the impact of failure is significant. When a breaker fails, thousands of customers will experience an outage that typically lasts one to two hours. Circuit breaker failure is most likely to occur when the breaker is triggered to operate. When a circuit breaker fails, the next upstream protection device at the station bus is then triggered to operate. A fault that was otherwise localized on a feeder would then extend to all of the customers supplied by that station bus, potentially disrupting anywhere from 1,000 to 10,000 customers depending on the bus.

Toronto Hydro experienced an outage of this nature when an outdoor breaker at Finch TS failed to open. The bus protection system was forced to operate, interrupting power to nearly 5,000 customers. Most customers were restored within three hours of the initial incident; however, all of those customers were supplied by feeders that would not have suffered an outage had the breaker operated as intended.

Beyond the outage impact to customers, KSO oil circuit breakers run the risk of failing catastrophically. In this situation, the circuit breaker explodes and sets fire to its oil, potentially damaging equipment, injuring personnel in the vicinity and impacting the surrounding environment. In addition to heightened safety risk, catastrophic failures also pose the risk of environmental damage due to oil leakage.

To mitigate the reliability and safety risks noted above, Toronto Hydro plans to replace the 12 TS outdoor breakers identified in Table 8 below during the 2025-2029 period. All of the breakers proposed for replacement are beyond their 45-year useful life expectancy and contain or are at risk of containing degraded oil. Toronto Hydro will prioritize the breakers presenting the highest failure risk for work during the 2025-2029 period.

Table 8: TS Outdoor Breakers Proposed for Replacement

Station	Breaker Type	Feeder	Load Served	Replacement Year
Bathurst TS	*KSO Oil Circuit Breaker*	85-M23	33 MVA	2025
Bathurst TS	*KSO Oil Circuit Breaker*	85-M32	32 MVA	2025

Leslie TS	*KSO Oil Circuit Breaker*	51-M22	16 MVA	2026
Leslie TS	*KSO Oil Circuit Breaker*	51-M29	24 MVA	2026
Leslie TS	*KSO Oil Circuit Breaker*	51-M30	20 MVA	2027
Leslie TS	*KSO Oil Circuit Breaker*	51-M32	17 MVA	2027
Finch TS	*KSO Oil Circuit Breaker*	55-M31	26 MVA	2028
Finch TS	*KSO Oil Circuit Breaker*	55-M32	25 MVA	2028
Fairchild TS	*KSO Oil Circuit Breaker*	80-M21	12 MVA	2028
Fairchild TS	*KSO Oil Circuit Breaker*	80-M22	13 MVA	2028
Fairchild TS	*KSO Oil Circuit Breaker*	80-M23	19 MVA	2029
Fairchild TS	*KSO Oil Circuit Breaker*	80-M24	18 MVA	2029

With the proposed plan and timeline shown in Table 8, below shows the overall state of all TS outdoor circuit breakers within Toronto Hydro's system along with their status in 2029.

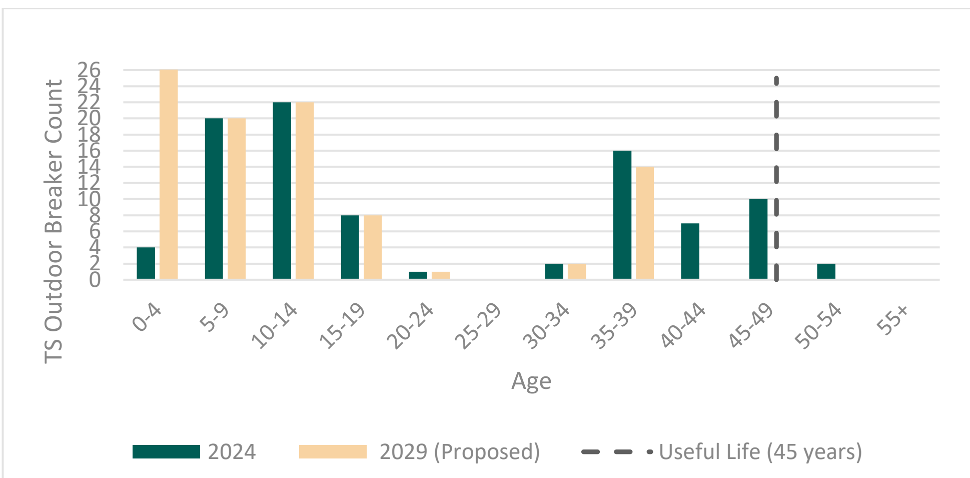


Figure 10: TS Outdoor Breaker Age Demographics at the end of 2024

As per Figure 11, these assets are located at stations serving customers located in the North York area. Once this work is complete, customers and loads connected to these four stations will face reduced risk of power disruptions resulting from breaker failure.

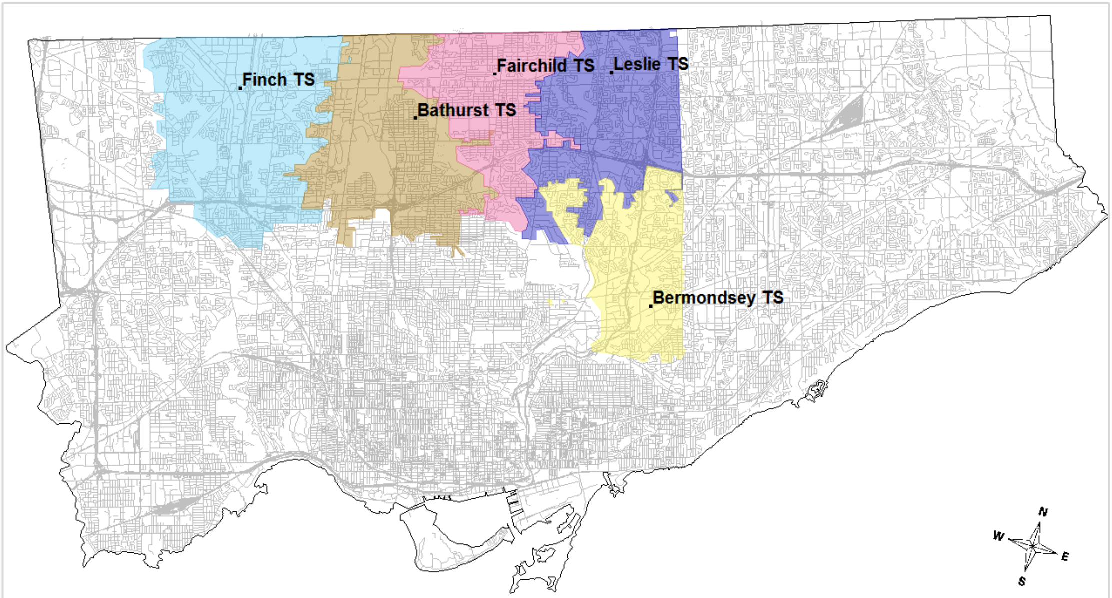


Figure 11: Toronto Hydro-owned TS containing outdoor circuit breakers.

3. TS Outdoor Switches

In addition to owning breakers at the five North York stations identified in Figure 11 above, Toronto Hydro also owns 230 TS outdoor switches located at the same stations. By the end of 2024, 7 percent of these TS outdoor switches will be operating beyond their 50-year useful life. The majority of them have never been replaced since their original switchgear or breaker installations.

Many of these switches have failed in recent years because of their age and deteriorated condition. Personnel have noted difficulty operating these switches, citing that in many cases, excessive force is required to close or open them. This risks damage to the switches and injuries to workers, as difficult to operate switches create safety issues like arc-flash.

Toronto Hydro does not have a Health Index for these switches. Switches are manual devices that either open or close when operated. Therefore, their condition is best captured by relying on visual assessment by Toronto Hydro field personnel and their experiences operating these switches. To increase the reliability of Toronto Hydro's grid system, Toronto Hydro plans to replace 63 TS outdoor switches during the 2025-2029 rate period as outlined in Table 9 below.

Table 9: TS Outdoor Switches Proposed for Replacement

Station	Feeder Tie Switch	Line Disconnect Switch	Total Switches	Replacement Year
Bathurst TS	2	4	6	2025
Bathurst TS	2	4	6	2026
Fairchild TS	3	6	9	2026
Fairchild TS	3	7	10	2027
Finch TS	5	11	16	2028
Leslie TS	5	11	16	2029
Total	**20**	**43**	**63**	

As shown in

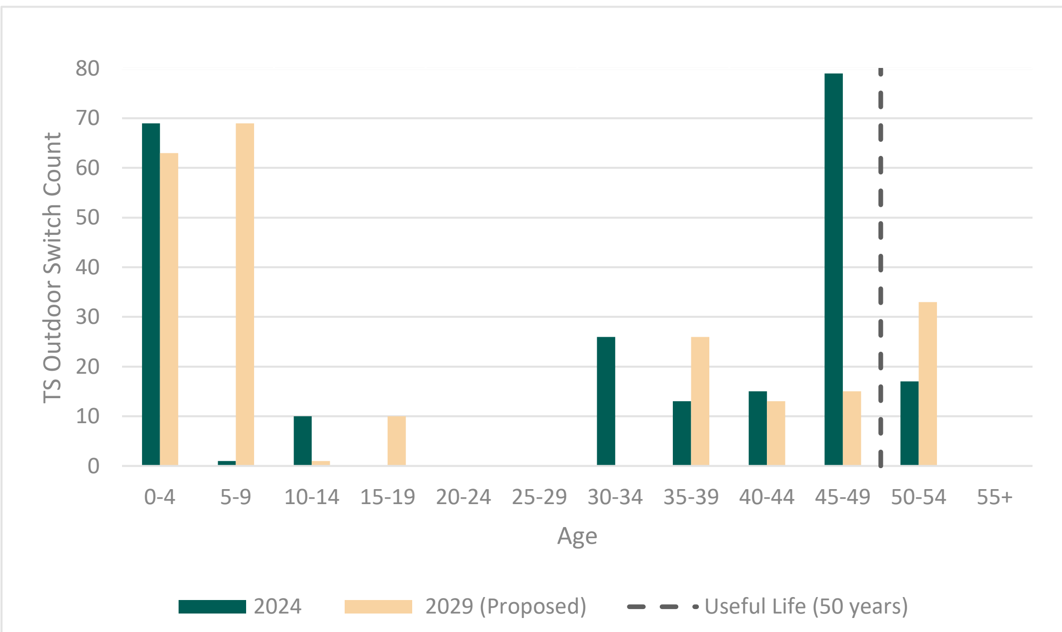


Figure 12 below, 17 of Toronto Hydro's TS outdoor switches will be operating beyond their 50-year useful life by the end of 2024. Without investment, an additional 79 switches will be operating past their useful life in 2029. Without action during the 2025-2029 rate period, 40 percent of Toronto Hydro's TS outdoor switches will be beyond or within five years of their useful life expectancy by 2029. In order to maintain the condition of its TS switches, Toronto Hydro plans to replace 63 TS outdoor switches. This will reduce the proportion of switches within or beyond their useful life from 40 percent to 20 percent by 2029.

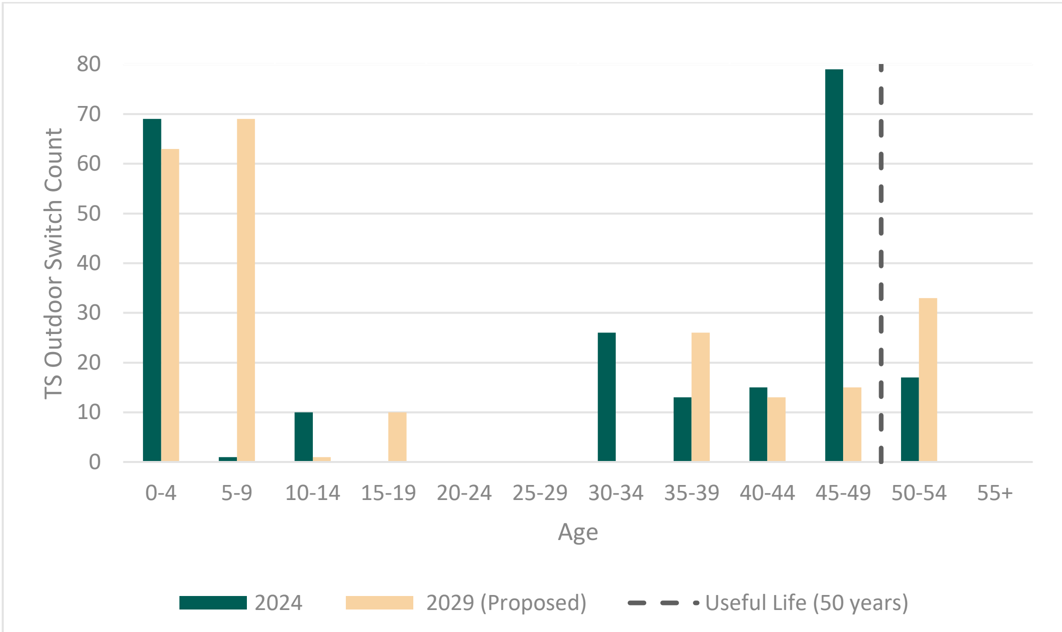


Figure 12: TS Outdoor Switch Age Demographics

Figure 13: Repair of TS Outdoor Switch

E6.6.3.2 Municipal Stations ("MS")

Toronto Hydro's MS supply power to Toronto's suburban areas consist largely of residential and a few small general service customers (<1 MW). Major MS assets include switchgear, power transformers, and MS primary supplies composed of disconnect switches and power cable. A large portion of these assets are operating well beyond their useful life and are consequently at a heightened risk of failure. The investments proposed under this segment will maintain MS reliability by replacing deteriorated and obsolete assets at MS without upcoming voltage conversion plans.

A given MS supplies hundreds to thousands of customers. All connected customers experience a power outage if any of that MS major assets fail. A power supply must be switched to an adjacent MS in order to restore power to customers. This process typically takes half an hour to six hours. Following this restoration of power, the failed asset is repaired or replaced over a period of weeks or months.

Should an additional failure occur at an adjacent MS, then it is possible that during peak times brown outs (rotating outages) may be imposed on customers until one of the MSs is restored to service. This is because the MS distribution system is not designed to support a MS failure when its backup source is out of service.

For similar reasons, maintenance and renewal work at adjacent MS cannot be overlapped. As the population of MS assets get older without a proper renewal plan, the risk of having an MS failure when its backup source is not available becomes higher. Thus, asset renewal and maintenance plans become more difficult to execute while managing the risk of interrupting service to customers. Where possible, Toronto Hydro coordinates end-of-life asset replacements at a single MS during the same year, rather than having replacements and outages spread over multiple years.

1. MS Switchgear

The useful life of a MS Switchgear is 50 years. All of the MS switchgear targeted for replacement, listed in Table 10, will be between 58-65 years old at their time of replacement. None of them are arc-resistant and they are all equipped with technically obsolete circuit breakers which are no longer supported by manufacturers. One switchgear proposed for replacement utilizes oil circuit breakers, while the rest utilize air magnetic circuit breakers. As seen in Figure 14 below, almost half the population of the MS air magnetic circuit breakers is forecasted to progress to HI4-Material Deterioration by 2029 without investment. Operating these breakers in this condition increases failure risks, which can be mitigated with the proposed replacements.

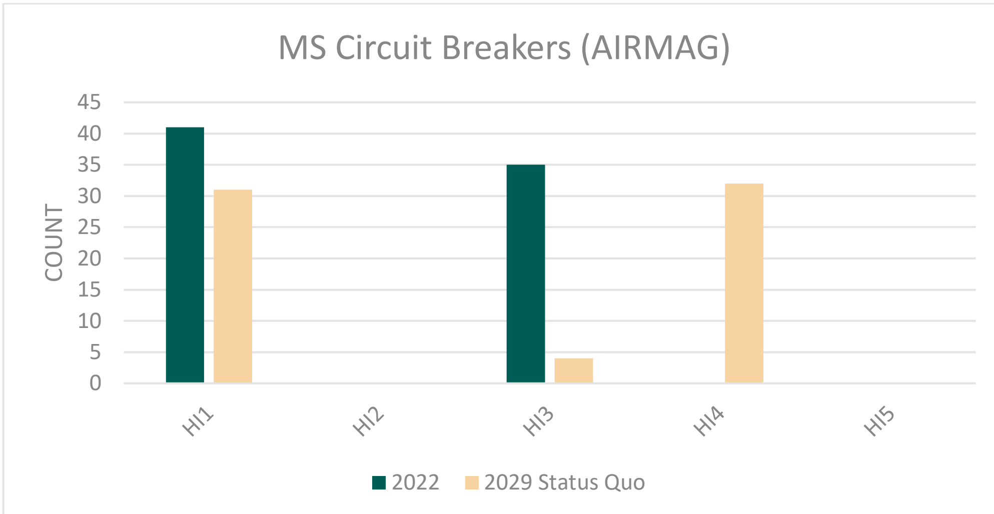


Figure 14: Condition of MS Air Mag Circuit Breakers as of 2022 and 2029 without investment

The switchgears proposed for replacement are functionally obsolete, and replacement parts are no longer available. This makes maintenance of the existing switchgear difficult and expensive, as replacement parts need to be custom made or scavenged from other switchgears. Replacement with new switchgears supported by current manufacturers will allow Toronto Hydro to more efficiently maintain the switchgear as individual components fail in the future.

The switchgears planned for replacement over the 2025-2029 period, shown in Table 10 below, are currently showing signs of deterioration and are anticipated to have circuit breakers with at least in HI4-Material Deterioration by 2029.

Table 10: MS Switchgear Proposed for Replacement

Station	Switchgear	Age at Replacement	Replacement Year
Elmhurst MS	T1SG	63	2025
Midland Lawrence MS	T1SG	61	2025
Hardwick MS	T1SG	65	2026
Windsor MS	T1SG	58	2026
Oberon MS	T1SG	61	2027
Palmwood MS	T1-T2SG	61	2027
Hunting Ridge MS	T1SG	61	2028
Renforth MS	T1SG	63	2028

Station	Switchgear	Age at Replacement	Replacement Year
Walney MS	T1-T2SG	61	2028
Belfield MS	T1-T2SG	65	2029
Braeburn MS	T1SG	61	2029
Centennial Darcy Magee MS	T1SG	58	2029

New switchgears will be arc-resistant and installed with vacuum circuit breakers, a low-maintenance and reliable model of circuit breakers. Each switchgear replacement will also involve the installation of a new SCADA (supervisory control and data acquisition) system at the station since the existing system has far surpassed its useful life and is highly integrated with the switchgear. As a result, MS switchgear renewal will also aid in Toronto Hydro's efforts to renew its fleet of RTUs, as discussed in Section E6.6.3.3 below.

Figure 15 shows the age profile of Toronto Hydro's MS switchgear in 2024 and 2029 under the proposed renewal and conversion plans (see the Area Conversions program, Overhead System Renewal, and Underground System Renewal - Horseshoe, which will remove a switchgear from service).[2]

The failure risk increases as the asset runs past its useful life. At a certain point (i.e. the target maximum age), that failure risk is deemed to be unacceptably high. The proposed renewal plan will result in no units that exceed 65 years (i.e. the new target maximum age) by 2029. Similarly, with the proposed renewal plan, the number of switchgears aged past useful life in 2029 will be similar to that at the end of 2024, and is broadly expected to maintain MS reliability. Figure 15 shows that the proposed plan results in nearly a flat age profile over ages 50-64 years. This will permit stable and executable pacing for the Segment over the next 20 years.

[2] Exhibit 2B, Section E6.1.

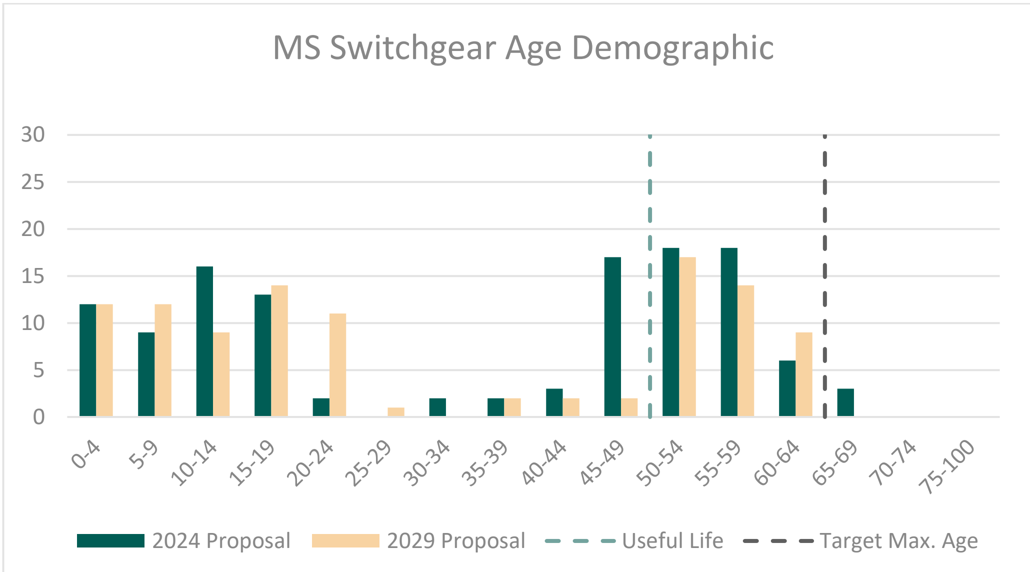


Figure 15: Age Profile of MS Switchgear

2. Power Transformers

The useful life of a power transformer is 45 years. If no investment is made to replace power transformers, there will be an increase in power transformers reaching conditions of material deterioration and end of serviceable life by 2029, as shown in Figure 16 below.

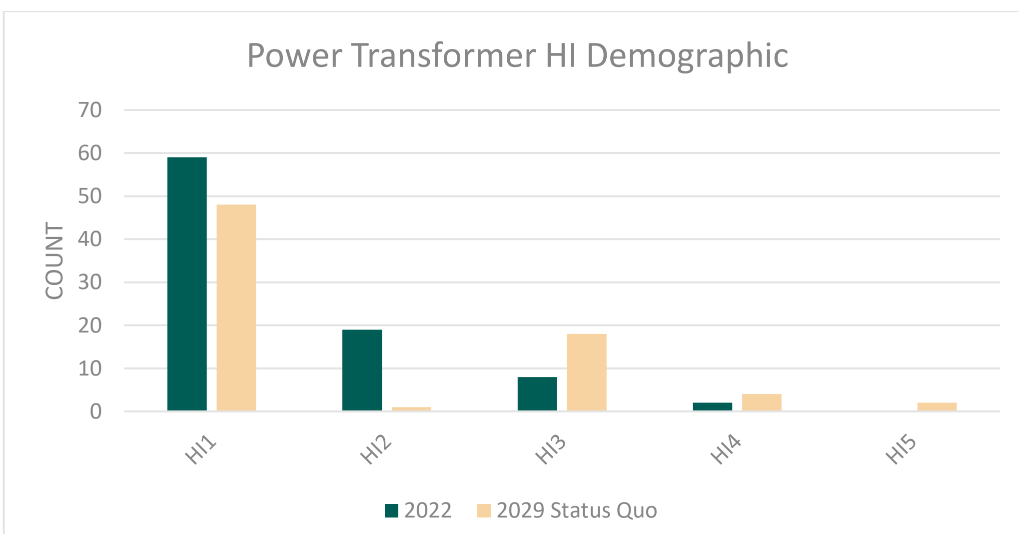


Figure 16: Power Transformer Asset Condition as of 2022 and in 2029 without investment

Over the 2017-2022 period, Toronto Hydro experienced an increased number of power transformer failures, shown in Figure 17. This increase in failures occurred despite decreasing numbers of units past useful life (45 years) as shown in Figure 17 and Figure 18.

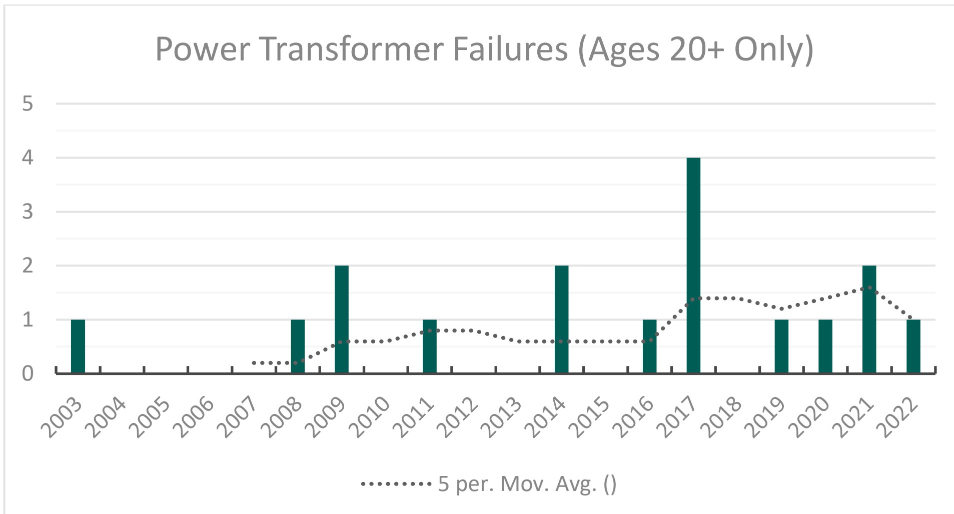


Figure 17: Count of Power Transformer Failures

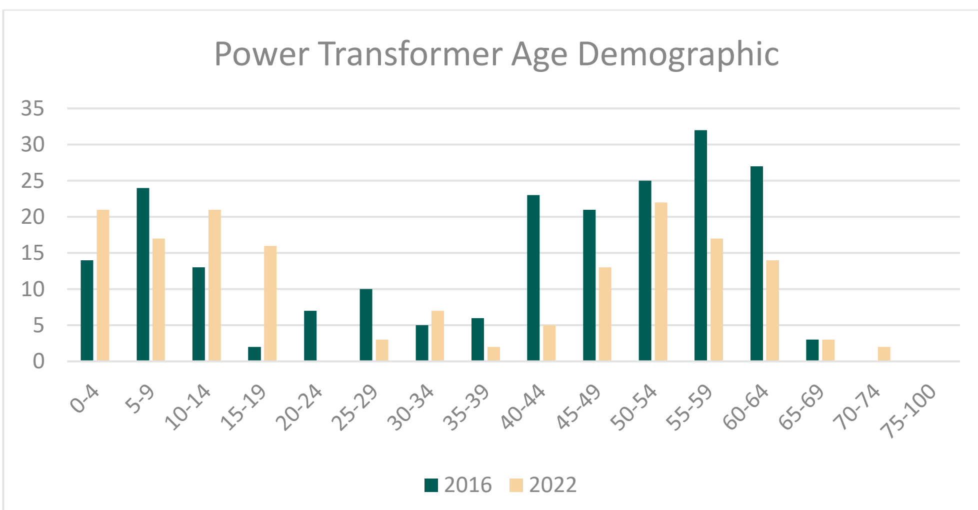


Figure 18 : Power Transformer Population Demographics in 2016 and 2022

To address this emerging trend, Toronto Hydro has taken two actions. First, Toronto Hydro has revised its target maximum age for its power transformers down from 70 to 65 years, in alignment with previous rate applications. The failure risk increases as the asset runs past its useful life. At a certain point (i.e. the target maximum age), that failure risk is deemed to be unacceptably high, as was observed in the 2020-2024 rate period. If a MS major asset fails, then all connected customers (hundreds to thousands) will experience an outage where restoration would typically occur in half and hour to six hours. The subsequent repair or replacement of the failed asset occurs over a period of weeks or months. By adopting the new target maximum age, the utility intends to avoid reactive replacement. Second, Toronto Hydro is proposing to increase the pace of renewal over 2025-29 compared to 2020-2024, which is discussed in further detail in Section E6.6.4.2.

In addition to customer outages, power transformer failures can have significant safety and environmental impacts on an MS. Upon failure, the tank of the power transformer can rupture, result in oil fire, and even explode. Power transformers hold thousands of litres of oil, which upon failure can result in oil spills and fuel large fires.

All transformers targeted for replacement over 2025-2029, listed in Table 11, will be 54-66 years old at the time of replacement. This level of pacing is required to combat an increased failure rate and ensures the utility is not replacing an increased number of power transformers in the next rate application period. Units will be replaced with units of the same or lesser capacity, where possible, to minimize costs. For example, the failure of power transformers listed in Table 11 that are slightly past their useful life would impact a comparatively large proportion of customers. Planned renewal work is necessary because the reactive replacement of a failed unit takes three to six months to complete even with spare transformers on hand.

Table 11: Power Transformers Proposed for Replacement

Station	ID	Additional Concerns	Replacement Age	Replacement Year
Elmhurst MS	2491	• High power factor • Low insulation resistance	66	2025
Hartsdale MS	2403	• Very high power factor • Low insulation resistance	65	2025
Midland Huntingwood MS	2808	• High power factor & poor power factor sweep • Low insulation resistance	56	2025
Windsor MS	2472	• Questionable power factor • Low insulation resistance	62	2026
Canadine Midland MS	2778	• Low oil dielectric breakdown	60	2026
Palmdale Sheppard MS	2824	• Questionable power factor	53	2026
Oberon MS	2471	• Very high power factor	64	2027

Station	ID	Additional Concerns	Replacement Age	Replacement Year
		• Low insulation resistance		
Palmwood MS	2484	• DGA[3] indications of arcing • Questionable power factor	67	2027
Dunsany MS	2408	• N/A	67	2027
Hunting Ridge MS	2492	• Questionable power factor	64	2028
Sheppard Kennedy MS	2805	• Questionable power factor • Low oil dielectric breakdown • Low paper degree of polymerization	58	2028
Meteor MS	2505	• High power factor	59	2028
Braeburn MS	2442	• High power factor • Low insulation resistance • Poor winding resistances	64	2029
Centennial MS	2412	• N/A	66	2029
Belfield MS	2504	• N/A	60	2029

Figure 19 below shows the age profile of Toronto Hydro's power transformers at the end of 2024 and 2029 under the proposed replacement and conversion plans (see the Area Conversions, Underground System Renewal – Horseshoe, and Overhead System Renewal Programs), which will remove power transformers from service.[4] Toronto Hydro identified 17 power transformers which to be replaced over the 2025-2029 rate period due to their condition, age, and failure impact. Under the proposed replacement plan, noticeable decreases in the number of units past useful life will be maintained by 2029, and the number of units aged beyond the target maximum age of 65 will be nearly equal compared to 2024.

[3] Dissolved gas analysis ("DGA") is a test often used to identify previous and/or persistent thermal and/or electrical faults occurring within a power transformer.
[4] Exhibit 2B, Section E6.1; Exhibit 2B, Section E6.2; Exhibit 2B, Section E6.5

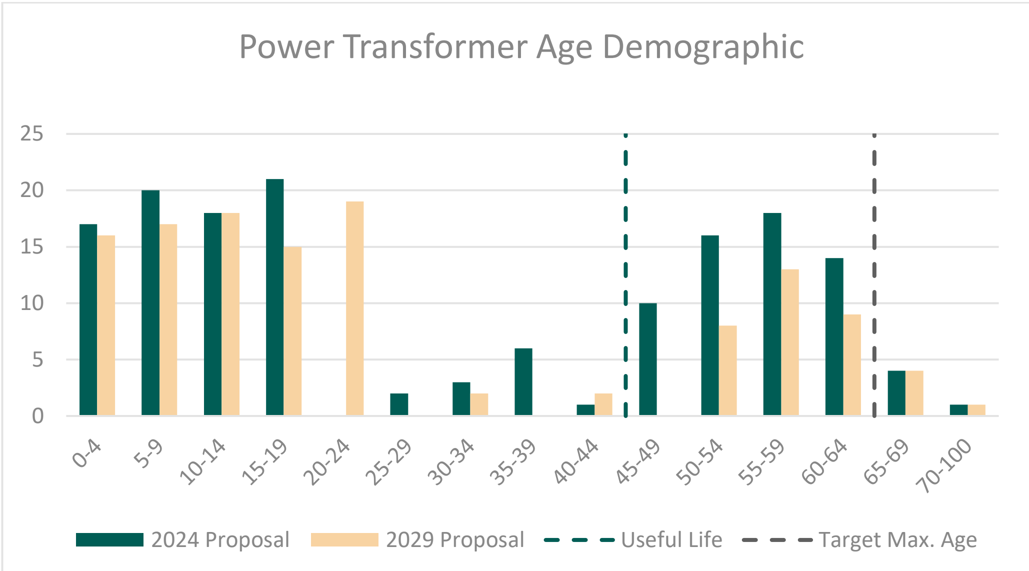


Figure 19: Age Profile of Power Transformers

Although newly installed power transformers contain no PCBs, a release of transformer insulating fluid must still be remediated and potentially reported according to the Environmental Protection Act.[5] To this end, Toronto Hydro will also install an oil containment system as part of its power transformer replacements. Toronto Hydro has been following this practice for all of its power transformer replacements since 2017. The oil containment system will prevent the release of oil into the environment should the power transformer develop an oil leak or tank rupture due to failure. Transformer replacements will also include the replacement of the transformer's primary supply, as Toronto Hydro has been doing for all of its power transformer replacements over 2020-2024.

By replacing the end-of-life power transformers targeted in this segment, Toronto Hydro will mitigate the risk of power transformer failure at its Municipal Stations, thereby maintaining the reliability of its MS.

3. MS Primary Supply

The MS primary supply, or station ingress, consists of all assets in the station between the distribution system and the primary side of the station transformer, including primary cable and a primary disconnect switch (or occasionally circuit breaker). These assets are used to supply the

[5] Environmental Protection Act, R.S.O. 1990, c. E.19. Article 92, 93.

station transformer with power, or to disconnect the transformer from its supply for maintenance or during a fault. It takes three months to reactively replace a failed primary supply.

Prior to 2019, power transformer replacements were typically completed without replacing their MS primary supply. As part of this segment, Toronto Hydro proposes to continue replacing the primary supply at MS where power transformers were previously replaced, but only where the primary cable is direct buried or in direct buried duct since this comprises the majority of the failure risk.

Over the 2025-2029 rate period, Toronto Hydro proposes to replace the primary supply at one MS as listed in Table 12. The proposed station was selected on the basis of failure risk as determined through the age and configuration of the primary supply assets.

Following this project, the remaining primary supplies in the system will be renewed with their power transformer as part of the scope of a power transformer renewal project, as has been done since 2019. This work will mitigate the risk of a primary supply failure.

Table 12: MS Primary Supplies Proposed for Replacement

Station	Age at Replacement	Replacement Year
Markham Pandora MS	63	2027

The useful life for a primary disconnect switch or a primary circuit breaker is 45 years. For non-lead primary cable, present at the proposed stations, the useful life typically ranges from 25-50 years, depending on the type of cable. All MS primary supplies will be past their useful life at the time of proposed replacement.

The existing primary disconnect switches are obsolete end-of-life assets. They can no longer be replaced like-for-like as they are non-standard and no longer manufactured. Primary disconnect switches will be replaced with a standard padmounted switch commonly used in Toronto Hydro's distribution system.

By replacing the end-of-life and obsolete MS primary supplies, Toronto Hydro will mitigate the failure risk these assets pose at its MS, thereby maintaining MS reliability.

E6.6.3.3 Control and Monitoring

Toronto Hydro uses control and monitoring systems at its TS and MS to protect its equipment, provide operators with system oversight, and allow for remote switching operations. Ultimately this allows Toronto Hydro to reduce outage durations and provide customers with higher reliability. Major Control and Monitoring assets include RTUs and protection relays.

During the 2020-2024 rate period, Toronto Hydro prioritized and is on track to complete the installation of new RTUs at MS that did not have any monitoring systems. Toronto Hydro also prioritized and is on track to complete the Interstation Control Wiring upgrades from copper to fiber (which will result in the removal of that subsegment since it is no longer required). However, there are still copper communications remaining on the system between TS and customers which are planned to be addressed during the 2025-2029 rate period through Relay Renewals.

The 2020-2024 rate period also introduced the Pilot-Wire Protection renewals which has since been expanded to replace other higher risk protection relays such as URD distribution relays and transfer trip relays in the downtown Toronto region.

In addition, Toronto Hydro proposes to modernize its fleet of station relays as part of its Grid Modernization Roadmap.[6] Toronto Hydro will replace its obsolete electromechanical relays with modern digital relays, in order to improve its system observability to the levels needed to achieve an intelligent grid. Toronto Hydro's drivers for its Control and Monitoring assets are summarized in

[6] Exhibit 2B, Section D.5.

Table 13 below.

Table 13: Control and Monitoring

Subsegment	Description	Drivers and Failure Consequences
RTU Renewal	RTU Replacement	The main driver is the failure and risk of aging TS/MS RTUs with secondary driver of functional obsolescence since some RTUs have technology that the suppliers are either no longer in business, replacement parts are no longer available, or minimal support is available to the product from the manufacture. The consequence of an RTU failure is a loss of telemetry data and remote control operation at the station. The loss of remote control operation would increase outage durations for any potential outages that may occur.
Relay Renewal	TS/MS Relay Renewal	The main driver is the modernization of old electromechanical relays to digital relays. The benefit of upgrading the relays to digital is the ability to record events for historical view of issues, as well as better relay diagnostics, enhanced outage fault location, and enhanced protection system security.
	Transfer Trip Relay Renewal	The main driver the risk to replace aging electromechanical Transfer Trip protection systems as well as the copper communication cables used for larger customers. Toronto Hydro would look to replace these assets with digital relays and fiber communication cables respectively. Failure consequence of these systems is an outage to the large customer who rank reliability as their highest priority.
	Pilot-Wire Protection Renewal	The main driver is the risk to replace aging electromechanical pilot-wire protection systems as well as the copper communication cables used for larger downtown customers (including financial institutions, hospitals, telecom companies, sewage plants, etc.). Toronto Hydro would look to replace these assets with digital relays and fiber communication cables respectively. The consequence of these systems failing is an outage to large customer who rank reliability as their highest priority.

Control and Monitoring assets are common to both TS and MS and vary in size and complexity depending on the station and its geographical location. Systems located in downtown Toronto TS are treated with a higher priority than systems located in MS. However, systems in all stations are important because control centre operators rely on them to oversee, control, and protect the system. Modern operation of the electrical grid relies upon having real-time data and control available at the station level at all times.

1. RTU Renewal

As shown in Table 14 below, 29 percent of Toronto Hydro's RTUs are planned to be operating as obsolete RTUs or beyond their useful life of 22 years as of 2024.[7] Many of Toronto Hydro's RTUs are still built from early computer technologies. Computer technology has advanced considerably in the past 25 years making it difficult to find replacement parts that maintain backwards compatibility with what are now obsolete technologies (i.e. MOSCAD, DACSCAN, D20 ME, SEL 3332, SEL 2032).

Table 14 below shows the RTUs in various geographical areas, and the percentage of RTUs that are in-service beyond their useful life (as of the end of 2029 without investment). The number of obsolete RTUs drops to 18 percent due to a combination of planned MS Conversion, MS Switchgear Renewals, and Relay Renewals, all of which either remove the obsolete RTU or replace it.

Table 14: RTU Asset Demographic Plan

Region	Number of Assets	Obsolete / Past Useful Life 2024	Obsolete / Past Useful Life 2029 (Without investment)	% Obsolete / Past Useful Life 2024	% Obsolete / Past Useful Life 2029 (Without Investments)
Etobicoke	64	2	0	3%	0%
North York	22	11	3	50%	14%
Scarborough	37	14	12	38%	32%
Toronto	58	26	17	45%	29%
Total	**181**	**53**	**32**	**29%**	**18%**

Most of Toronto Hydro's D20 ME RTUs are younger than 22 years. However, some units have suffered premature failures over recent years. Moreover, modification to these units requires use of legacy computer operating systems which are no longer supported by the original RTU manufacturer. Similar to MOSCAD and DACSCAN RTUs, like-for-like replacement parts for legacy D20 RTUs are no longer available for purchase. To resolve these issues, Toronto Hydro proposes to replace these units with newer, non-legacy models which are currently supported.

Last, most of Toronto Hydro's SEL 2032s (MS) and SEL 3332 (TS) RTUs, similar to the D20 MEs, have been discontinued by the manufacturer. As a result, support is minimal and finding replacement

[7] An RTU has a useful life of 22 years as identified in the Kinectrics Report K418021 "Useful Life of Assets", August 28, 2009.

units is difficult since Toronto Hydro has to use spare parts if available from previously installed equipment at stations which no longer require their RTU from renewal or from decommissioning.

When an RTU fails, Toronto Hydro's control centre operators lose control and visibility of equipment at the station, leaving the system in a vulnerable state. If an RTU failure occurs at a critical station, field crews need to be dispatched to the station immediately to manually monitor equipment status and operate where required. This is necessary to ensure Toronto Hydro can adequately respond to outages and prevent equipment damage by ensuring the station operates within its limits. Combined with the difficulty of the repair work required, this makes a failure event operationally expensive and puts customers at risk of longer outages.

To mitigate RTU failure risk, Toronto Hydro plans to replace 33 RTUs in total (19 at the TS, 14 at the MS). With the exception of RTUs at stations with planned switchgear renewal or MS conversions, this plan will result in replacing all at risk RTUs.

2. Relay Renewal

Relay Renewal is a continuation and expansion of Toronto Hydro's Pilot-wire Protection Renewal work from the 2020-2024 rate application. Relay renewal over the 2025-2029 rate period will focus on four categories: TS Electromechanical to Digital Renewal; MS Electromechanical to Digital Renewal; Transfer Trip Relay with Copper Communications; and Pilot-Wire Relay with Copper Communications. The renewal of Toronto Hydro's relays is mainly driven by modernization, to allow for Toronto Hydro to monitor the system with higher accuracy, allowing fault recording, relay diagnostics, and better discrimination of and coordination with faults over a wider range of operational conditions. These benefits of digital relays will also help support Toronto Hydro's Grid Modernization Roadmap by improving Toronto Hydro's system observability and controllability.

While the renewal of Toronto Hydro's Relays is mainly driven by modernization for the majority of relays; the Pilot-Wire Protection Systems along with the Transfer Trip Relays are driven by failure risk due to their age, obsolete copper communications, and importance to the individual larger customers served by Toronto Hydro that require these assets for their distribution needs.

Table 15 below shows the categorization and amount of Relay types.

Table 15: Relay Type, Quantity, and Useful Life

Relay Type	Number of Assets	Obsolete / Past Useful Life 2024	Obsolete / Past Useful Life 2029 (Without Investments)	% Obsolete / Past Useful Life 2024	% Obsolete / Past Useful Life 2029 (Without Investment)
TS Relay	1063	419	407	39%	38%
MS Relay	724	371	221	51%	31%
Pilot Wire Relay	71	14	14	20%	20%
Transfer Trip Relay	33	7	7	21%	21%
Total	**1891**	**811**	**649**	**43%**	**34%**

The Transfer Trip Relay and Pilot-Wire Relay Renewals will focus on replacing the Relays along with the aging copper communication wires between the TS Relay to the Customer. This will both modernize the system while also mitigating failure risk of older copper wires. Toronto Hydro's planned switchgear replacements require circuit transfers with this protection system to the new switchgear. An upgrade to newer line protection technology is required since new switchgears cannot be made compatible with the obsolete pilot-wire protection relays.

The relay renewal program overlaps with TS/MS Switchgear Renewal as well as MS Conversions which would remove the need for the asset.

Table 15 above shows a reduction of the total relays obsolete/past useful life in 2024 to 2029 from 43 percent to 34 percent, which is mainly due to MS relays from MS switchgear renewal and MS Conversion plans.

Without a protection relay to isolate a feeder fault, the switchgear's bus differential protection would isolate the entire bus in the event of a fault. Consequently, events that should have been a single element failure, impacting a smaller set of customers, would become an entire TS switchgear outage affecting thousands of customers. In addition, defective electromechanical relays are very difficult to diagnose and most often Toronto Hydro discovers a faulty relay once it causes an issue like not tripping the breaker when it should or nuisance-tripping the breaker. New digital relays can avoid these issues since they have self-diagnostics which are part of the benefits and goals of Toronto Hydro to achieve an intelligent grid.

These improvements to replace electromechanical and copper-based relay protection systems with digital relays and fiber communications have the following benefits:

- Replacing obsolete assets allows Toronto Hydro to meet public policy outcomes, accommodate increasingly sophisticated customer needs (e.g. vehicle-to-grid, peak shaving, and distributed energy resources applications), operate its system more efficiently, and provide increased value to customers.
- Upgrading to digital relays will support the Grid Modernization Roadmap which requires both system observability (fault locating and system loading and condition) and system controllability (ability to easily control the grid and to make system "self-healing" in future).
- Better discrimination and coordination with faults over a wider range of operational conditions;
- New relays have self-diagnostics which simplifies troubleshooting and makes failures easier to predict;
- New relays have fault recording which can help diagnostics and more accurately find outage trends on a give feeder, bus, switchgear, etc.
- Less manual maintenance and testing since the new system has online monitoring and self-diagnostics; and
- As part of each project, copper lines are replaced with fiber. Toronto Hydro will have complete control of the fiber optic communication cables and not be reliant on a privately-owned third-party corporation (many copper cables are owned by Bell); therefore, a faster

response time can be provided by Toronto Hydro crews in the case of communication line failure.

Toronto Hydro plans to replace 100 TS and 130 MS Electromechanical Relays with Digital Relays. The plans from

Table 15 above, along with current planned Switchgear Renewal work and MS Conversions would replace a total of 497 Electromechanical Relays out of 700 (TS, MS, Pilot Wire, Transfer Trip combined). This would equate to having 21 percent of the system still with either electromechancial relays or relays past their typical useful life or obsolete by 2029.

Toronto Hydro also plans on renewing 7 Transfer Trip Relays and 14 Pilot-Wire Relays along with the Copper Communication Wires to be Fiber. This renewal plan would conclude upgrading the Transfer Trip Relays and Pilot-Wire Relays to Digital Relays as well as conclude the Copper Renewal plans.

E6.6.3.4 Battery and Ancillary Systems

As shown in Table 16 below, ten percent of Toronto Hydro's Battery and Ancillary Systems will be operating beyond their useful life in 2024. Depending on the asset, replacement is required due to poor condition, end of useful life, obsolescent technology, or a mixture of these factors. The Battery and Ancillary Systems segment proposes replacing these supporting systems as required to maintain station integrity and system reliability for Toronto Hydro customers.

Table 16: Battery and Ancillary Systems Demographics

Asset Type	Total # of Assets	Useful Life	Assets Beyond Useful Life (2024)	Assets Beyond Useful Life Without Program (2029)	Assets Beyond Useful Life with Program (2029)
Battery	148	10	18	69	14
Charger	148	20	11	20	16
Station Service Transformers	44	45	3	3	0
AC Panels	21	-	5	5	0
Air Compressors[8]	14	15	0	0	0
Total	**361**		**37**	**97**	**30**
Percentage			**10%**	**27%**	**8%**

In addition to the renewal of the assets included in the table above, Toronto Hydro has three TS with flood risk requiring mitigation, as detailed in sub-section 4 below. Furthermore, Toronto Hydro has also identified five stations that require new AC panels to mitigate the failure risk of those panels

[8] No work is planned for in 2025-2029 as no air compressor is beyond useful life. During 2020-2024 one Air Compressor was replaced reactively and the other station was sold to a third party.

with obsolete circuit breakers that have reached the end of their useful life. Sub-section will discuss the AC panel replacements in more detail.

1. Battery and Charger Renewal

A battery and charger system is installed at every TS and MS to provide DC power supply and backup for essential protection, control, and SCADA systems. Due to their critical function, station batteries and chargers must be maintained in reliable condition. These systems must be able to supply power for a minimum of eight hours after the loss of main AC power. As shown in Table 17 below, 11 percent of Toronto Hydro's MS batteries, 19 percent of Toronto Hydro's TS batteries, 9 percent of Toronto Hydro's MS charger systems and 0 percent of TS charger systems will be operating beyond their useful life in 2024.

Table 17: Battery and Charger Systems Demographics

Asset Type	Assets Beyond Useful Life (2024)	Assets Beyond Useful Life Without Program (2029)	Assets Beyond Useful Life with Program (2029)
MS Battery	11%	43%	11%
TS Battery	19%	62%	0%
MS Charger	9%	16%	13%
TS Charger Systems	0	4%	0%

Previously, Battery & Chargers were grouped together into a single category. However, batteries and chargers have different useful lives and replacement schedules and MS and TS unit costs differ by large margins. Toronto Hydro is now providing a breakdown into sub-parts as shown in Figure 17 above.

Battery and charger system renewal is required to mitigate failure risk. All station batteries have a useful life between 10-12 years (depending on the battery type). Batteries deteriorate to the point of failure as they age and a significant number of them are past or close to the end of their useful life. Charger Systems have a typical life of 20 years and once they exceed their useful lives, they are at risk of failing and jeopardizing the station's DC system.

Without replacement, failures are expected to increase resulting in reduced reliability for Toronto Hydro customers as well as significant equipment damage. When a battery or charger fails, its MS or

TS loses the source of DC power supply. This in turn renders all protection, control, Station RTUs, and other communication systems non-functional. Failure of protection and control systems is a major safety and reliability risk as the station would lose its ability to isolate faults, potentially resulting in a station outage. Otherwise, loss of functionality would affect the Control and Monitoring systems with similar failure impacts to those detailed in Section E6.6.3.3.

Therefore, there is a need to maintain the system reliability by ensuring fewer batteries and charger systems continue to operate beyond their useful life. Figure 20 below highlights the decrease in assets past their useful life by replacing the proposed 55 battery units thus minimizing reliability risks.

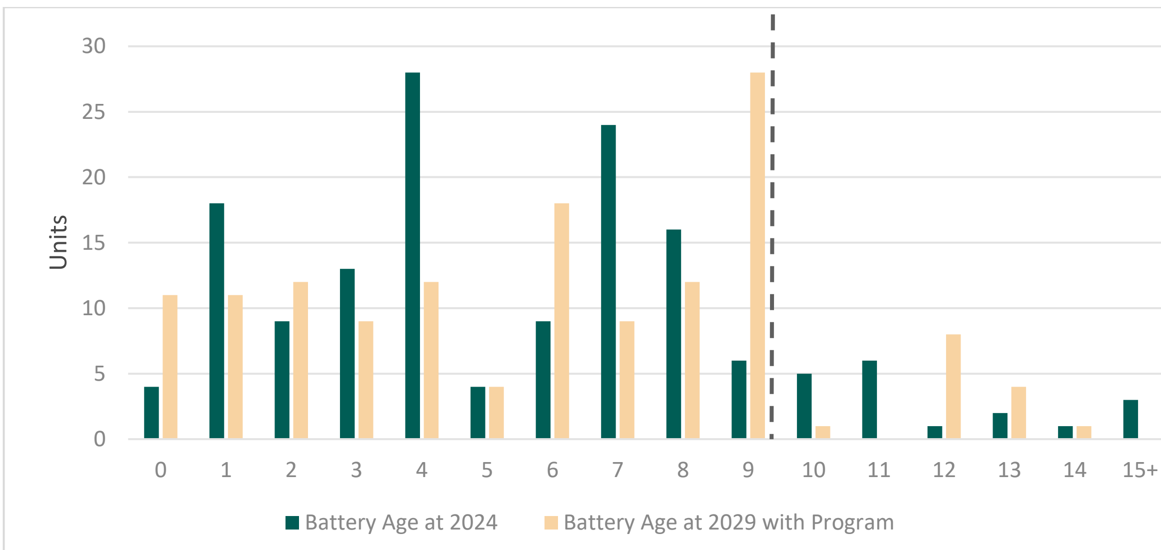


Figure 20: Age Profile of Station Batteries

As listed in Table 18 below, Toronto Hydro plans to replace 55 station batteries over the 2025-2029 rate period, which consist of 16 TS batteries, eight charger systems, and one TS charger. When replacing batteries and chargers, Toronto Hydro will also replace any end-of-life or obsolete DC panels and other smaller series components with similar failure impact.

Table 18: Battery & Charger Proposed Replacement Plan

Year of Replacement	Downtown Replacements	North York Replacements	Scarborough Replacements	Etobicoke Replacements	Total
2025	6	0	5	2	**13**
2026	3	0	4	4	**11**
2027	4	0	3	7	**14**

2028	3	0	5	5	**13**
2029	3	2	4	3	**12**
Total	**19**	**2**	**21**	**21**	**63**

2. Ancillary Renewal

Several ancillary systems require replacement or installation to maintain the integrity of Toronto Hydro's station infrastructure. Toronto Hydro's most pressing risks and needs for these ancillary assets are summarized in Table 19 below.

Table 19: Other Ancillary Systems - Drivers

Asset Group	Asset Class	Drivers and Failure Consequences
Ancillary Systems	*Sump Pumps*	The main driver for this segment is the failure risk of station assets due to flooding. The stations selected for sump pump installation have major equipment installed in the basement (e.g. switchgear, station services etc.) that is at risk in case of water infiltration. Lack of sump pumps can lead to a water build-up which could eventually short-circuit and damage equipment.
	Station Service Transformer (SST)	A station service transformer ("SST") supplies a station with AC power for use in the station's heating, cooling, lighting, ancillary equipment, and DC charging systems. Therefore, an SST failure has a similar impact as a charger failure. Due to this significant failure impact, Toronto Hydro installs two SSTs at its downtown TS. SST replacement projects will only target SSTs supplying these TS. SST renewal is required to mitigate failure risks associated with their age. In addition to the loss of critical systems identified above, a failure of an oil-containing SST has a risk of causing a fire or explosion. Most SSTs are located in close proximity to other critical station assets and pose risk of collateral damage. Therefore, SST replacements will mitigate this safety and environmental risk.
	AC Panels	All the stations loads such as heating, cooling, lighting, ancillary equipment, and DC charging systems are supplied from AC Panels. Unlike SSTs there is no back up for AC panels, therefore, an AC Panel failure has a more severe impact compared to both SST and DC charger failure. The main driver of replacing AC panel is failure risk of obsolete

Asset Group	Asset Class	Drivers and Failure Consequences
		and end-of-life assets. The 5 proposed AC panels are the oldest in the system, which are all more than 50 years old.

AC Panels have the largest failure impact among all battery and ancillary equipment. When an AC panel fails, the SST cannot supply AC power to any of the station loads such as station's heating, cooling, lighting, ancillary equipment, and DC charging systems. Also, no back up AC supply can be brought in. Therefore, the station will have no AC power and only eight hours of DC supply until the AC panel is replaced. During this time, DC supply can be maintained by bringing in a diesel generator and connecting it to the battery charger in order to avoid loss of DC supply for the critical systems. AC panel replacement could take anywhere between a few weeks to few months as the lead times are unknown.

To mitigate the risks identified above, Toronto Hydro plans to replace three sump pumps at the stations identified in the table below.

Table 20: Proposed Sump Pump Replacements

Station	Replacement Year
Glengrove	2025
Wiltshire	2028
Danforth	2029

Toronto Hydro owns 44 SSTs which supply its downtown TS. Three SSTs, equivalent to 7 percent of total SSTs, will be past useful life by 2024, as summarized in Table 21. Other than the three SSTs mentioned, no other SST will reach their useful life during the 2025-2029 rate period. Based on the risk level and relatively low cost of SST replacements, investments will be made to avoid having any of these assets past useful life.

Table 21: Station Service Transformer Demographics

Asset Type	Assets Beyond Useful Life Current State (2024)	Assets Beyond Useful Life Without Program (2029)	Assets with PCB >2ppm
Stations Service Transformers	7%	7%	0

There were originally two SSTs which were assumed to have PCBs (Charles TS, Dufferin TS), both of which have been replaced during 2020-2024 rate period. As shown in Figure 21, all of the targeted SSTs will exceed their typical useful life of 45 years by 2024.[9] Without action during the 2025-2029 rate period, 7 percent of these SSTs will be operating beyond their useful life by 2029.

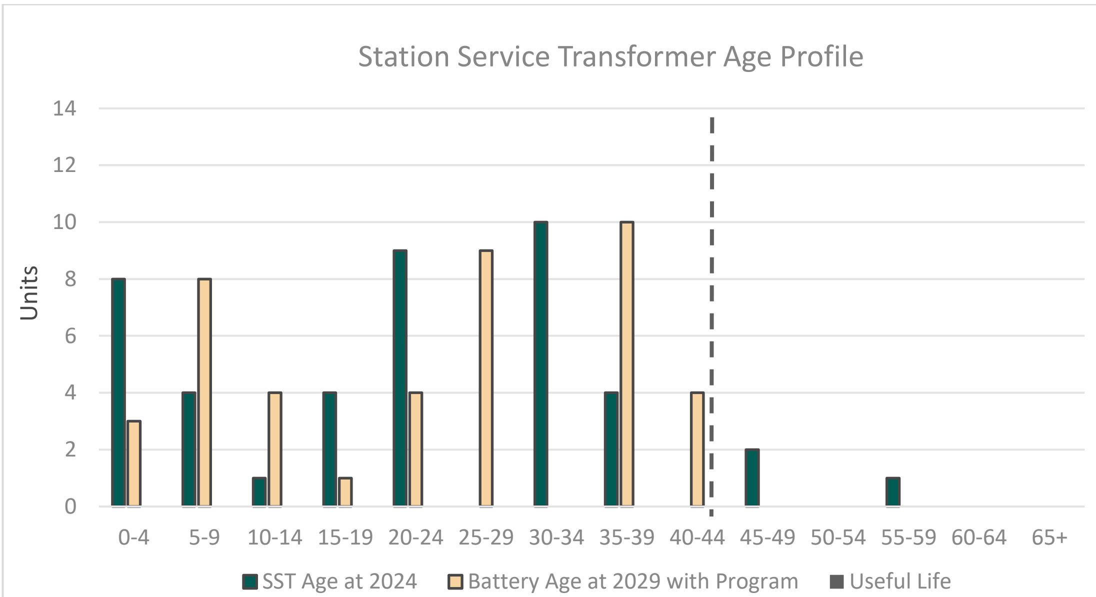


Figure 21 : Age Profile of Station Service Transformers

As listed in Table 22 below, Toronto Hydro plans to replace one SST at each of the three TS during the 2025-2029 rate period. This will significantly mitigate the risk of coincident SST failures at these TS, and in turn will mitigate customer outage risk.

Table 22: Proposed SST Replacements

Station	Asset	Replacement Year
Carlaw	*SST1*	2025
Basin	*SST1*	2026
Charles	*SST2*	2028

Toronto Hydro owns 21 AC Panels in both Downtown and Horseshoe TS. Of these Toronto Hydro plans to replace five AC panels over the 2025-2029 rate period as shown in the table below

[9] An SST has a useful life of 45 years as identified in the Kinectrics Report K418021 “Useful Life of Assets”, Aug. 28, 2009.

Table 23 : Proposed AC Panels replacements

Station	Replacement Year
Carlaw	2025
Dufferin	2026
Duplex	2027
Charles	2028
Cecil	2029

E6.6.4 Expenditure Plan

Table 24 provides the Historical (2020-2022), Bridge (2023-2024) and Forecast (2025-2029) expenditures for the Stations Renewal Program. The Program has been organized in 2025-2029 based on the type of system addressed, work required, and driver of the work.

Table 24: Historical & Forecast Program Costs ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Stations TS	12.0	16.7	18.8	18.8	28.8	31.1	31.1	30.0	25.0	16.8
Stations MS	11.5	12.4	2.4	3.9	14.3	10.2	11.3	13.4	17.0	18.4
Stations Control & Monitoring	4.7	3.1	5.1	6.5	8.8	11.9	12.1	13.5	13.1	14.2
Stations Ancillary and Battery	1.9	1.2	1.1	2.2	0.8	3.2	2.2	1.9	3.4	2.9
Total	**30.2**	**33.6**	**27.4**	**31.4**	**52.8**	**56.4**	**56.7**	**58.8**	**58.6**	**52.3**

Spending in the Stations Renewal Program over the 2025-2029 rate period is forecasted to be $282.8 million. This is higher than the $174.7 million forecast in the 2020-2024 Distribution System Plan ("DSP") due to higher than expected project complexity, incremental increases to project scope across multiple projects, and higher than expected inflation costs. However, Toronto Hydro expects to largely complete the projects it had proposed in the 2020-2024 DSP, with the exception of the TS switchgear projects, which have experienced a number of delays.

Complexities involved in the Transformer Stations segment contributing to increased costs include the procurement of unique TS switchgear which meet Toronto Hydro's stringent safety and reliability requirements. As for the Municipal Stations segment, project scope has expanded to include a larger scope of station civil and building refurbishment to support electrical asset renewals, which has also driven unit costs upwards.

For the 2025-2029 rate period, Toronto Hydro proposes to invest $282.8 million, which is a substantial increase compared to the 2020-2024 rate period. This increase is approximately equally split between an increased work volume, and forecasted inflation. Across all segments, an increased work volume is needed relative to the 2020-2024 rate period to maintain station asset demographics. Toronto Hydro utilizes these demographics to set pacing for the 2025-2029 rate period and then, individual projects are then selected based off an overall assessment of risk (See Tables 29, 32, and 35). As discussed in Section E6.6.3, station assets are critical with large failure impacts and have lengthy replacement times. Maintaining station asset demographics is the best strategy to prevent their high failure impact and, in turn, maintain system reliability.

Another substantial increase in work volume is being introduced under the Control and Monitoring segment, where Toronto Hydro's proposes to replace all of its obsolete station electromechanical relays with modern digital relays by 2034.[10] This pacing is proposed to prepare Toronto Hydro's distribution system for modernization, support increasingly sophisticated customer needs, and provide increased customer value through better control and operability.

Work in the Stations Renewal Program is prioritized at three different levels. First, TS work is prioritized above MS work, since TS supply customers of all classes and serve more customers than MS. Therefore, the TS segment as a whole and the portions of the Control and Monitoring and Battery and Ancillary Systems relevant to TS are given the highest priority. Second, the work inside each segment is prioritized differently depending on the specific failure outcomes and risks associated with each asset class. Finally, with respect to each asset class, work is prioritized using a variety of data and considerations including age, condition, obsolescence, customers served, load served, and maintenance effort.

E6.6.4.1 TS Segment Expenditure Plan

As shown in Table 25, Toronto Hydro expects to spend $95.2 million over the 2020-2024 rate period in its Transformer Stations segment. This is $20.7 million higher than the 2020-2024 Distribution System Plan forecast of $74.5 million. Toronto Hydro forecasts that it will complete an additional

[10] Relays which are part of switchgear which have a switchgear replacement planned within 22 years of 2034 are excluded. Otherwise, the newly replaced relays will be replaced again with the switchgear before the useful life of the relays has been reached. The useful life of a digital relay is 22.5 years.

three outdoor breakers and eight outdoor switches in the 2020-2024 rate period than was previously forecasted. The increase is mainly attributed to procurement challenges resulting in increased unit costs. A variance analysis for each subsegment is provided in the following subsections.

Table 25: TS Historical & Forecast Segment Costs ($ Millions)

Expenditures	Actuals			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
TS Switchgear	8.4	15.8	15.6	14.7	27.3	28.9	27.8	27.2	19.8	12.9
TS Outdoor Breakers	1.7	0.8	2.1	1.6	0.7	1.4	1.5	1.5	3.1	1.6
TS Outdoor Switch	1.8	0.1	1.2	2.4	0.8	0.7	1.9	1.3	2.1	2.2
Total	**12.0**	**16.8**	**18.8**	**18.8**	**28.8**	**31.1**	**31.1**	**30.0**	**25.0**	**16.8**

For the 2025-2029 rate period, Toronto Hydro proposes to spend $134 million in the TS segment, completing seven switchgear, 12 outdoor KSO breakers and 63 outdoor switches. As with the 2020-2024 rate application, the majority of the 2025-2029 spending is planned for TS switchgear renewal. The remainder is for the replacement of TS outdoor breakers and TS outdoor switches.

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete two new TS switchgear projects, complete partial work on four new TS switchgear projects, and has completed one carry-over project from the 2015-2019 rate period. The total cost of this work over 2020-2024 is $81.9 million. The 2020-2024 Filed Plan proposed replacing KSO breaker replacement projects for a total cost of $4.0 million, and therefore expenditures are forecasted to be overspent by $2.95 million while unit volume is forecasted to be three units above target. Due to the deferral of the Finch BY bus upgrade from Hydro One in 2020, the Toronto Hydro breaker replacement was deferred as well. In order to continue improving our grid system, five KSO breakers and 18 associated switches that were in poor condition on the BY bus was replaced instead at Finch TS. As a result, all the proposed work from the previous rate application period was completed with five additional units, but at a higher cost than proposed. Table 26 provides the forecasted spending for each project over the 2020-2024 period.

Table 26: 2020-2024 TS Switchgear – Forecast Costs and Completion Year ($ Millions)

Switchgear Unit	Forecasted 2020-24 Costs	Planned Completion	Carry Over From 2015-2019
Strachan A7-8T	1.9	2021	Yes
Carlaw TS A4-5E	12.3	2023	No
Strachan TS A5-6T	18.8	2023	No
Bridgman TS A1-2H	18.8	2025	No
Duplex TS A1-2DX	7.6	2027	No

Switchgear Unit	Forecasted 2020-24 Costs	Planned Completion	Carry Over From 2015-2019
Windsor TS A5-6WR	8.0	2027	No
Wiltshire TS A5-6WA	14.4	2026	No
Total	**81.9**		

Since TS switchgear projects span multiple years and rate periods, a discussion of project cost better informs the magnitude of the subsegment spend increase. Table 27 below summarizes the project cost variances and major sources.

Table 27: TS Switchgear for the 2020-2024 Period

Switchgear Unit	Total Project Cost		Project Completion		Major Sources of Variances
	Filed Plan	Current Forecast	2020-24 Filed Plan	Current Forecast	
Carlaw TS A4-5E	11.0	12.3	2022	2023	• Switchgear procurement • Load transfer • Metering
Strachan TS A5-6T	14.3	18.8	2023	2023	• Switchgear procurement • Site preparation (Duct banks)
Bridgman TS A1-2H	14.7	18.8	2024	2025	• Switchgear procurement • DC System Upgrade
Duplex TS A1-2DX	10.2	7.6	2023	2027	• Switchgear procurement • Site preparation (RTU relocation)
Windsor TS A5-6WR	18.4	8.0	2024	2027	• Switchgear procurement • Contingency reinforcement
Wiltshire TS A5-6W	-	14.4	-	2026	• New project addition to the 2020-24 period
Strachan TS A7-8T	-	3.5	-	2021	• 2015-2019 Carry-over project

Over 2020-2023, Toronto Hydro has experienced unexpected challenges selecting and procuring TS switchgears that meets the utility's needs in the space-constrained downtown Toronto. First, the procurement challenges affected all projects throughout 2020-2024, increasing the project cost and delaying the proposed schedule from the previous rate application. Additionally, Toronto Hydro's switchgear supplier discontinued its production of and support for TS switchgear that met the utility's space requirements in 2022. To mitigate supply risks, Toronto Hydro has started to reach out to new manufacturers in efforts to resolve these challenges for the 2025-2029 rate period. The additional time spent on sourcing supplier also caused the schedule delay of switchgear replacement. Preliminary cost estimates show that a 30-50 percent increase for switchgear units is expected.

The two notable projects, Duplex A1-2DX and Windsor A5-6WR, will require additional time for the switchgear procurement, delaying both projects from the previous projected completion date. Toronto Hydro will continue with sourcing suppliers to prevent the future projects from experiencing similar challenges moving forward.

Furthermore, TS switchgear replacement has accrued more costs than prior years due to site conditions. Referencing previous projects, site preparations required additional work to relocate major assets such as more complicated civil work, RTU cabinets and station service transformers in order to facilitate the installation of the new switchgears.

1. TS Switchgear – 2025-2029 Expenditure Plan

Over the 2025-29 period, Toronto Hydro will complete four TS switchgear projects started in the 2020-2024 rate period, complete three new TS switchgear projects, and complete one new building project as advanced site preparations.[11] This presents a minor increase in the number of switchgear replacements under construction over the rate period, relative to the previous rate period. Table 28 below provides the annual spend for each project over the 2025-2029 rate period.

Table 28: 2025-2029 TS Switchgear – Forecast Expenditures ($ Millions)

Switchgear Unit	Cost	Completion Year	Carry Over from 2020-2024
Bridgman TS A1-2H	5.6	2025	Yes
Duplex TS A1-2DX	15.5	2027	Yes
Windsor TS A5-6WR	16.2	2027	Yes
Wiltshire TS A5-6WA	6.4	2026	Yes
Danforth MS A1-2DA	16.1	2029	No
Bridgman TS A7-8H	21.9	2029	No
Windsor TS A3-4WR	21.7	2029	No
Bridgman TS A1-2B – Hydro One Building renovation	13.3	2029	No

[11] These building projects are estimated to have lead times of approximately 5 years, and are needed before select TS switchgear projects planned for 2030-2034 can begin.

Switchgear Unit	Cost	Completion Year	Carry Over from 2020-2024
Total	**117.0**		

Toronto Hydro has further mitigated risks to achieving its 2025-2029 replacement plan by proposing five TS switchgear replacements over the 2025-2029 rate period. One switchgear replacement is building preparation only. This is the renovation of the Hydro One building for Bridgman due to lack of space for new switchgear installation in the existing TS. The four carry over units are Bridgman A1-2H, Duplex A1-2DX, Windsor A5-6WR and Wiltshire A5-6WA. It is forecasted that $43.6 million will be required to complete the work, which includes the expenditures made in 2020-2024. Three units - Danforth A1-2DA, Bridgman A7-8H, and Windsor A3-4WR - will start work within the 2025-2029 rate period, at a forecast spending of $59.8 million, which is required to complete the projects within the 2025-2029 rate period. One unit that will start its initial site preparations over the 2025-2029 rate period, Bridgman A1-2B, is forecasted to cost $13.3 million and will carry over to the 2030-2034 period. By completing this plan, Toronto Hydro will maintain the number of TS switchgear operating beyond their useful life around the current level, which is approximately 32 percent.

This work plan is attainable (and necessary to manage the aging and deteriorating TS switchgear population) in light of the change in circumstances and preparations made during the 2020-2024 rate period. For example, allocating more resources to coordinate with different switchgear suppliers in 2020-2024 will allow switchgear replacements to proceed smoothly during construction. Other projects, largely being carry-overs, have known execution risks and challenges that have been addressed over the 2025-2029 rate period. To plan for TS switchgear replacements for 2025-2029, a feasibility study of six selected switchgears were performed to provide an outline and summary of the project to budget and schedule, and also mitigate the risk of replacement. Currently, four of the six reports have been completed. The remaining feasibility studies will look into each TS on its own regarding specific issues and forecast issues field staff may experience during execution and provide solutions and projected funding to plan for switchgear renewal projects.

Toronto Hydro believes that accepting the increased risk, specifically the risk of continuing to operate these units beyond their useful life, is prudent and necessary in the context of its overall TS Switchgear replacement needs, priorities, and ability. With continued maintenance and monitoring, Toronto Hydro will mitigate failure risk until the units can be replaced.

Toronto Hydro prioritizes the replacement of its TS switchgear in order of the failure risk presented by each switchgear. The failure risk is assessed qualitatively by considering the following factors.

Table 29: TS Switchgear Prioritization

Factor	Prioritization
Age	Older switchgear are given higher priority
Enclosure Construction	Brick constructed switchgear is given higher priority
Condition Assessment	Switchgear receiving worse condition assessments (including breaker condition assessments) are given higher priority
Type of circuit breaker	Priority given in order of: 1) Obsolete non-oil air blast circuit breaker 2) Obsolete asbestos-based air magnetic circuit breaker 3) Current SF_6 circuit breakers 4) Current vacuum circuit breakers
Load	Switchgear supplying larger quantities of load are given higher priority
Protection and Control	Switchgear with obsolete protection and control systems are given higher priority.
Arc Flash Rating	Switchgear with lower arc flash protection ratings are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority

Age and condition assessment are used to gauge the probability of a switchgear failure and when an asset has reached end-of life. Type of circuit breakers, enclosure construction and arc flash rating help determine which of the old standards switchgears that requires renewal. Load and protection and control are used to gauge the impact of the switchgear failure and priority of the replacement.

TS outdoor breakers and switches are located in different stations than TS outdoor breakers and switches, TS switchgear units have longer replacement and lead times and more complex design and construction, and require more capital investment. For these reasons, TS switchgear are prioritized above the other assets in the TS segment, and in the Stations Renewal Program overall.

2. TS Outdoor Breaker – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro expects to spend $6.95 million to replace twelve outdoor KSO breakers at Fairchild TS, Leslie TS, Finch TS, and Bathurst TS. Table 30 below provides an annual breakdown of the forecasted expenditures and the units completed over the 2020-2024.

Table 30: TS Outdoor Breakers - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-2024
Units (Breakers)	2	0	3	5	2	12
Expenditures ($M)	1.7	0.84	2.1	1.6	0.68	7.0

The 2020-2024 Filed Plan proposed replacing KSO breaker replacement projects for a total cost of $4.0 million, and therefore expenditures are forecasted to be overspent by $2.95 million while unit volume is forecasted to be three units above target. Due to the deferral of the Finch BY bus upgrade from Hydro One in 2020, the Toronto Hydro breaker replacement was deferred as well. In order to continue improving our grid system, five KSO breakers and 18 associated switches that were in poor condition on the BY bus was replaced instead at Finch TS. As a result, all the proposed work from the previous rate application period was completed with five additional units, but at a higher cost than proposed.

The 2020-2024 Filed Plan estimated unit cost per breaker replacement at roughly $0.44 million, totalling $4 million for nine units. As a result, the forecasted unit cost over 2020-2024 has increased to $0.6 million above the unit cost for 12 units provided in the 2020-2024 Distribution System Plan of $0.44 million per breaker. The main sources for unit cost increases are: additional work for implementation of Hydro One requirement for demarcation concept, the complex protection scheme for key account customers and material inflation throughout the 2020-2024 rate period.

3. TS Outdoor Breaker – 2025-2029 Expenditure Plan

For the 2025-2029 period, Toronto Hydro proposes to replace 12 KSO breakers, which is the same amount as the previous period. The forecasted cost to complete this work is $9.08 million. Table 31 below provides the annual breakdown of the forecasted expenditures and unit completed over the 2025-2029 rate period.

Table 31: 2025-2029 TS Outdoor Breaker – Forecast Expenditures ($ Millions)

	Actual			Bridge		Total
	2025	**2026**	**2027**	**2028**	**2029**	**2025-2029**
Units (Breakers)	2	2	2	4	2	12
Expenditures ($M)	1.4	1.5	1.5	3.1	1.6	9.1

As mentioned in Section E6.6.3.1, the oil-based TS outdoor breakers within Toronto Hydro's system are past useful life and will be replaced with vacuum breakers. All of the 12 KSO breakers proposed for replacement contain oil and are operating beyond their useful life, and need to be replaced as detailed in Sub-Section TS Outdoor Breakers of Drivers and Need. By the end of 2029, Toronto Hydro aims to have no outdoor breakers operating beyond their useful life. The pacing of 12 units ensures that no breakers are past their useful life, allowing for increased reliability to be maintained both in short and long term and aligns to Toronto Hydro's standard of non-oil-base circuit breakers.

The average cost for TS outdoor breaker replacement over the 2025-2029 rate period is roughly $0.74 million per unit. This is slightly higher than initial unit pricing estimated for the 2020-2024 period which was $0.60 million per unit. From the four breaker replacements completed from 2020-2022, the actual cost increased to $0.61 million per unit due to material inflation and increased design and construction costs for new Hydro One demarcation panel requirements. Toronto Hydro has adjusted its 2025-2029 estimates accordingly, forecasting that replacement will cost $0.74 million per unit.

Given its 2020-2024 historical achievements in this segment, Toronto Hydro is well positioned to successfully execute its replacement plan for 2025-2029, which proposes at most four replacements in a single year.

Toronto Hydro prioritizes the replacement of its TS outdoor breakers based on the failure risk presented by each breaker. The failure risk is assessed qualitatively by considering the following factors.

Table 32: TS Outdoor Breakers Prioritization

Factor	Prioritization
Age	Older breakers are given higher priority
Type of circuit breaker	Priority given in order of: 1) Oil circuit Breaker

Factor	Prioritization
	2) SF_6 Breaker 3) Vacuum Breaker
Condition Assessment	Circuit breakers receiving worse condition assessments are given higher priority
Load	Breakers supplying larger quantities of load are given higher priority
Protection and Control	Breakers with obsolete protection and control systems are given higher priority.
Any other issues raised by station crews (such as broken components)	Given higher priority

The type of circuit breaker, protection, and control are used to gauge the impact of the circuit breaker and the priority. All KSO oil breakers are at their end-of-life and will be targets for replacements this rate application period.

4. TS Outdoor Switches– 2020-2024 Variance Analysis

As shown in Table 33 below, Toronto Hydro forecasts replace 69 TS outdoor switches during the 2020-2024 rate period for a cost total of $6.32 million.

Table 33: TS Outdoor disconnect switches - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Units (Switch)	3	6	18	23	19	69
Expenditures ($M)	1.8	0.11	1.2	2.4	0.83	6.3

The 2020-2024 Filed Plan proposed 61 TS switches replacements for a total cost of $1.9 million. With the deferral of Finch TS BY bus renewal, Toronto Hydro plans to allocate the funds to advance the other TS programs as explained in the previous sections. Toronto Hydro forecasts to replace 69 TS outdoor switches during the 2020-2024 rate period at a cost of $6.32 million.

The actual unit cost for the new outdoor switches is much higher than originally estimated in the previous rate application. The average unit cost per switch replacement is roughly $0.09 million, a substantial increase from the estimate of $0.03 million per switch. This Program was a new segment for the 2020-2024 rate application, resulting in higher variance due to lack of experience. The contributing factors for this increase were additional labour costs from the new switches that are gang-operated on ground and steel mount on existing structure, requiring modifications for installation and material cost inflation. Unit cost was $0.12 million from 15 outdoor switches replaced in 2020-2022. As more switch replacement projects occurs, the average of unit cost will be decreased as Toronto Hydro gains more design and installation experience.

5. TS Outdoor Switches– 2025-2029 Expenditure Plan

For the 2025-2029 rate period, Toronto Hydro is proposing to replace 63 TS outdoor switches, a small increase from the original planned units from the previous period. The forecasted cost to complete this work is $8.32 million. Table 34 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 34: 2025-2029 TS Outdoor Switch – Forecast Expenditures ($ Millions)

	Actual			Bridge		Total
	2025	2026	2027	2028	2029	2025-2029
Units (Switch)	6	15	10	16	16	63
Expenditures ($M)	0.74	1.9	1.3	2.0	2.2	8.3

By replacing 63 units during the 2025-2029 rate period, Toronto Hydro will reduce the number of TS outdoor switches operating beyond their useful life to 14 percent. As detailed in sub-section 3 of section E6.6.3.1 Transformer Stations, if this work is not undertaken during the 2025-2029 rate period, 40 percent of Toronto Hydro's TS outdoor switches will be operating beyond or within five years of their 50-year useful life. Performing the proposed work will allow Toronto Hydro to sustainably manage the demographics of its switches over the longer term and reduce the number of switch failures.

The year-by-year pacing for TS outdoor switch replacement has been developed to target the highest priority switches, while maximizing efficiencies in terms of construction and outage coordination. For the years 2025-2029, Toronto Hydro proposes replacements in sets of three switches per year because each selected set can be replaced in a single outage. This reduces unit costs and reliability risk to customers (which would be higher if each switch was replaced as a separate project).

Toronto Hydro forecasts a cost of $8.32 million over the 2025-2029 rate period to complete the 63 switch replacements. This results in an average unit cost of $0.13 million per switch project, an increase from the $0.12 million from the previous 2020-2024 rate period. The contributing factors for this increase are material and labour cost inflation.

Toronto Hydro prioritizes the replacement of its TS outdoor switches based on the failure risk presented by each switch, which is assessed qualitatively and outlined in Table 35.

Table 35: TS Outdoor Switches Prioritization

Factor	Prioritization
Age	Older switches are given higher priority
Switch Type	Priority given in order of: 1) Feeder tie switches 2) Bus disconnect switches 3) Line disconnect switches
Number of repairs	Switches with more repairs are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority

Due to the nature of switches, multiple switches will be grouped together for replacement in order to minimize the outage time.

E6.6.4.2 Municipal Stations (MS) Expenditure Plan

As shown in Table 36 below, Toronto Hydro plans to spend $44.6 million over the 2020-2024 rate period in its Municipal Stations segment to complete 12 MS switchgear, 12 power transformers, and four MS primary supplies. This presents an increase of $6.9 million compared to the 2020-2024 forecast of $37.7 million. The total number of power transformers is higher than the 2020-2024 Distribution System Plan.[12] The MS switchgear and MS primary supply are less than the proposed volumes in the DSP due to revised project scopes, an increase in the unit cost of MS primary supplies, an increase in civil and stations work, and distribution work (egress and MS primary supply replacement).

When Toronto Hydro originally estimated the costs in this segment for 2020-2024, the projects prior to 2019 did not include the replacement of the MS primary supply as a part of the transformer replacement and thus, no project or design estimates were completed at the time of writing the 2020-2024 rate application. Therefore, the estimates did not fully account for the aforementioned

[12] *Supra* Note 1

factors, such as the stations and distribution portions of work. A variance analysis for each subsegment is provided in the following subsections.

Table 36: MS Historical & Forecast Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
***MS Switchgear*[13]**	6.4	8.7	0.74	2.7	5.9	5.7	6.2	7.5	11.2	13.2
Power Transformer	3.7	2.6	1.6	0.65	8.1	4.6	5.1	5.3	5.9	5.2
MS Primary Supply	0.39	0.08	0.35	0.55	0.33	-	-	0.56	-	-
Total	11.5	12.5	2.4	3.9	14.3	10.2	11.3	13.3	17.0	18.4

During the 2025-2029 rate period, Toronto Hydro proposes to spend $70.3 million on its MS segment and renew 12 MS switchgear, 15 power transformers, and one MS primary supply. Expenditures are increased due to an increased unit cost (described in variance analysis), a modest increase in volume of work, projects with custom or higher capacity equipment, and forecasted inflation. The majority of the 2025-2029 spending relates to MS switchgear renewal ($43.7 million). The remaining spending is planned almost entirely for power transformers replacement, with only one MS primary supply project proposed for the rate period.

1. MS Switchgear – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete ten new switchgear projects and has completed two carry-over switchgear projects from the 2015-2019 rate period, for a total cost of $25.7 million. Table 37 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 rate period.

[13] Note: the 2020-2024 expenditures do not necessarily align with the volume of units completed since project costs were spread across 2-3 years.

Table 37: MS Switchgear - Historical Actual and Bridge Unit Volumes and Expenditures

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Units (Switchgear)	2	5	1	1	3	12
Total Feeders[14]	6	19	3	3	10	41
Expenditures ($M)	7.0	9.5	0.56	2.7	5.9	25.7

The 2020-2024 Filed Plan proposed 12 new switchgear projects for a total cost of $23.4 million, and therefore expenditures are forecasted to increase by $2.3 million. Although the forecasted unit volume is the same, the replaced units have changed slightly. Toronto Hydro has since updated its MS conversion plans by offloading two of the 12 switchgears and is no longer planning for asset renewals at these stations. As a result, Toronto Hydro achieved a sustained risk profile and completed all the proposed work, but at a slightly higher cost than forecasted.

The two carry-over switchgear projects incurred expenditures of $3.2 million over the 2020-2024 rate period and comprised seven feeders. This results in a forecasted net expenditure of $22.5 million for ten new switchgear projects comprising 34 feeders, and an average unit cost of $0.66 million per feeder. As a result, the forecasted unit cost over 2020-2024 has increased above the unit cost provided in the 2020-2024 Distribution System Plan of $0.6 million per feeder.[15]

Major sources for increases in unit cost are due to the practical implications of new arc-resistant switchgear, underestimation of egress replacement costs, and inflation of switchgear material cost.

1) New MS switchgears are arc-resistant. Thus, it usually requires substantial changes to the station building (including a complete rebuild of entire station floor), and additional relocation work of conduits and ancillary equipment.
2) The unit cost for egress replacement projects used in the 2020-2024 rate application was based on only one project that was completed, which did not end up being representative of average cost.

[14] This is the total number of feeders supplied by the switchgear whose replacements were, or are forecasted to be, completed in the specified year.
[15] *Supra* Note 1.

3) During the past few years, the material cost of switchgear has significantly increased by 47 percent from 2019 to 2022.

These sources have informed forecasted spending for the 2025-2029 rate period.

2. MS Switchgear – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro proposes to replace 12 MS switchgear, which is a modest increase from the previous period. Table 38 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 38: MS Switchgear - Historical Actual and Bridge Unit Volumes and Expenditures

	Forecast					Total
	2025	2026	2027	2028	2029	2025-29
Units (Switchgear)	2	2	2	3	3	12
Total Feeders[16]	6	7	7	10	11	41
Expenditures ($M)	5.7	6.2	7.5	11.2	13.2	43.7

To complete the proposed 12 MS switchgear replacements, comprising 41 feeders, Toronto Hydro forecasts a cost of $43.7 million over the 2025-2029 rate period. This results in an average unit cost of $1.07 million per feeder which is a substantial cost increase from the previous 2020-2024 rate period. This new unit cost is forecasted using the cost increasing trend for the previous years, which considers these factors: updated unit costs from the 2020-2024 rate period, renewal of custom equipment for four projects, and general forecasted inflation.

For most MS, and for historical projects, the MS supplies an overhead distribution system using standard overhead switches. However, over the 2025-2029 rate period, four projects are planned at MS supplying an underground distribution system, which use custom underground egressing switches. Since these are legacy equipment past useful life, located within the station between the switchgear and the distribution system, and are needed to operate the station, these switches require renewal in parallel with the switchgear.

[16] This is the total number of feeders supplied by the switchgear whose replacements were, or are forecasted to be, completed in the specified year.

The additional cost needed to replace the custom underground egressing switches, plus general forecasted inflation, is responsible for the remaining unit cost increase over the 2025-2029 period resulting in an average unit cost of $1.07 million per feeder.

Segment expenditures were forecasted based on project-level estimates for the 12 switchgear replacements proposed, and were informed by actual and forecasted project costs over the 2020-2024 rate period. Project estimates were adjusted based on station configuration as discussed above, rather than simply applying a single unit cost to all projects. Pacing has been chosen to evenly distribute the projects over the period.

Toronto Hydro prioritizes the replacement of its MS switchgear based on the failure risk presented by each switchgear. The failure risk is assessed qualitatively by considering the following factors.

Table 39: MS Switchgear Prioritization

Factor	Prioritization
Age	Older switchgear are given higher priority
Condition Assessment	Switchgear receiving worse condition assessments (including breaker condition assessments) are given higher priority
Type of circuit breaker	Priority given in order of: 1) Obsolete oil circuit breaker 2) Obsolete air magnetic circuit breaker 3) Current SF_6 circuit breakers 4) Current vacuum circuit breakers
Load	Switchgear supplying larger quantities of load are given higher priority
Resiliency of the surrounding distribution system to withstand switchgear failures	MS in areas of low resiliency are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need their assets to be replaced

Age, condition assessment, circuit breaker type, and issues raised by station crews are used to gauge the probability of a switchgear failure and when a switchgear has reached end-of-life. Furthermore, switchgear loading and resiliency of the surrounding distribution system (i.e. ability to withstand switchgear failures) are used to gauge the impact of the switchgear failure and the priority of the replacement.

3. Power Transformer – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro expects to complete 11 new power transformer projects and one carry-over power transformer project from the 2015-2019 period, for a total cost of $ 16.7 million. Table 40 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 period.

Table 40: Power Transformer - Historical Actual and Bridge Unit Volumes and Expenditures[17]

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Power Transformers	1	4	2	0	5	12
Expenditures ($M)	3.7	2.6	1.6	0.65	8.1	16.7

The 2020-2024 Filed Plan proposed ten new power transformer projects for a total cost of $10.3 million, and therefore expenditures are forecasted to be overspent by $6.7 million while unit volume is forecasted to be one unit above target. One unit was advanced from 2025-2029 plans to mitigate outage coordination risks for the 2025-29 rate period, and to begin accelerating the replacement pacing to address an increased failure rate.

The one carry-over transformer project incurred expenditures of $1.3 million over the 2020-2024 rate period. This results in a forecasted net expenditure of $15.4 million for the 11 new power transformer projects, and an average unit cost of $1.40 million. As a result, the forecasted unit cost over 2020-2024 has significantly increased above the unit cost provided in the 2020-2024 Distribution System Plan of $1.0 million.[18]

Major sources for increases in unit cost are due to underestimated civil and facilities modifications, underestimated distribution costs for MS primary supply replacement, and ground grid refurbishment.

[17] Note: the 2020-2024 expenditures do not necessarily align with the volume of units completed since project costs were spread across 2-3 years.
[18] *Supra* Note 1.

1) In the 2015-2019 rate application, MS primary supply replacement was not included as part of the transformer replacement. Thus, the substantial amount of cost, including the construction the foundation of large primary switch and construction of new concrete encased duct banks, transformer foundation, and facilities modifications to extend equipment clearances to modern standards, was largely underestimated.
2) Similarly, the distribution portion of the MS primary supply replacement was also underestimated.
3) The station ground grid is an asset vital to employee and public safety. While conducting the civil modifications, the ground grid was often found inadequate and / or degraded, and the deficiencies needed to be addressed.

4. Power Transformer – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro proposes to replace 15 power transformers, which is an increase from the previous period. The forecasted cost to complete this work is $26.0 million. Table 41 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 41: Power Transformer - Forecasted Unit Volumes and Expenditures

	Forecast					Total
	2025	2026	2027	2028	2029	2025-29
Power Transformers	3	3	3	3	3	15
Expenditures ($M)	4.6	5.1	5.3	5.9	5.2	26.0

To complete the proposed 15 transformer replacements, Toronto Hydro forecasts a cost of $26.0 million over the 2025-2029 rate period. This results in an average unit cost of $1.73 million, which is a cost increase from the previous 2020-2024 rate period. There are two factors which explain this cost increase: four projects with higher capacity transformers, and general forecasted inflation.

Over the 2020-2024 rate period, only one power transformer renewal project involved the renewal of a unit rated for 10 MVA. However, four such units are proposed for the 2025-2029 rate period. Such units not only have a higher material cost, but they also require a higher rated MS primary supply which also introduces higher material costs. Finally, a unit of this size requires a more sensitive protection scheme to protect it from faults, known as a transformer differential protection scheme.

This protection scheme introduces new equipment and requires a much more intensive engineering design, both of which contribute to a higher cost.

Segment expenditures were forecasted based on project-level estimates for the 15 power transformer replacements proposed, and were informed by actual and forecasted project costs over the 2020-2024 rate period. Lessons learned from variances in the 2020-2024 rate period have been incorporated into project estimates for the 2025-2029 rate period. Project estimates were adjusted based on transformer capacity as discussed above, rather than simply applying a single unit cost to all projects. Pacing has been chosen to evenly distribute the projects over the period.

Toronto Hydro prioritizes the replacement of its power transformers based on the failure risk presented by each transformer. The failure risk is assessed qualitatively by considering the following factors.

Table 42: Power Transformer Prioritization

Factor	Prioritization
Age	Older transformers are given higher priority
Dissolved gas-in-oil analysis	Transformers in worse condition are given higher priority
Condition Assessment	Transformers receiving worse condition assessments are given higher priority
Loading	Transformers loaded higher relative to their capacity are given higher priority
Load	Transformers supplying larger quantities of load are given higher priority
Resiliency of the surrounding distribution system to withstand transformer failures	MS in areas of low resiliency are given higher priority
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need their assets to be replaced

Age, dissolved gas-in-oil analysis, loading, and condition assessment involving electrical tests are used to gauge the probability of a power transformer failure and when an asset has reached end-of-life. Further, transformer loading and resiliency of the surrounding distribution system (i.e. ability to withstand power transformer failures) are used to gauge the impact of the power transformer failure and the priority of the replacement.

5. MS Primary Supply – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete the replacement of four MS primary supplies for a total cost of $1.70 million. Table 43 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 rate period.

Table 43: MS Primary Supply - Historical Actual and Bridge Unit Volumes and Expenditures

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Power Transformers	1	0	1	1	1	4
Expenditures ($M)	0.39	0.08	0.35	0.55	0.33	1.7

The 2020-2024 Filed Plan proposed 11 MS primary supply projects for a total cost of $3.9 million, and therefore expenditures are forecasted to be underspent by $2.2 million while unit volume is forecasted to be seven units below target.

Forecasted unit volume is below target, for three reasons. First, four projects were cancelled because, upon project scoping, the primary cable at these stations was found to be installed in concrete encased duct, which does not meet the criteria set out in Section E6.6.3.2. Second, two projects were cancelled because switchgear replacements were planned for these stations in the 2025-2029 rate period, and to coordinate MS renewal work, the scope of work has been incorporated with their switchgear replacements in 2025-2029. Lastly, one project was deferred to the 2025-2029 rate period to mitigate increased spending in the MS segment as a whole.

Over the 2020-2024 rate period, the average unit cost for the four completed MS primary supply projects is forecasted to be $0.43 million. As a result, the forecasted unit cost over 2020-2024 has increased above the unit cost provided in the 2020-2024 Distribution System Plan of $0.37 million.[19]

Major sources for increases in unit cost are similar to sources for cost increases to power transformer replacements, since the power transformer replacements from 2019 onwards included MS primary supply replacements. In particular, since no projects and no design estimates had been completed at the time of writing the 2020-2024 rate application, both the station and distribution portions of work were underestimated. Based on actual project costs of 2020 and 2022 projects, and estimates

[19] *Supra Note 1*

for 2023 and 2024 projects, the unit cost has been updated to reflect these variances for both station and distribution portions of work.

6. MS Primary Supply – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro proposes to replace one MS primary supply, because this is the last primary supply remaining in the system, which meets the criteria set out Section E6.6.4.2. However, transformer failures which require immediate replacement, without an opportunity to replace the MS primary supply in parallel, may introduce the need for additional MS primary supply replacements.

The cost estimated for the proposed project is $0.56 million. The increased cost relative to the 2020-2024 rate period is due to forecasted inflation.

E6.6.4.3 Control and Monitoring Expenditure Plan

As shown in Table 44 below, Toronto Hydro expects to spend $28.29 million over the 2020-2024 rate period in its Control and Monitoring segment. This presents an overspend of $6.19 million compared to the 2020-2024 Distribution System Plan forecast of $22.1 million.[20] Toronto Hydro forecasts to complete one more TS RTU, 14 more MS RTU, 36 more TS Relays (previously shown as five customer locations, but correlates to two relays per location), and 32km less interstation control wiring as compared to the Filed Plan. A variance analysis for each subsegment is provide in the following subsections.

Table 44: Control and Monitoring Historical & Forecast Segment Costs ($ Millions)

Expenditures	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
RTU Renewal	3.8	1.6	4.1	3.6	6.2	2.8	3.1	3.2	3.3	3.4
Relay Renewal[21]	New Subsegment					9.1	9.1	10.3	9.8	10.7
Pilot-wire Protection Renewal	0.36	1.4	1.1	2.6	2.2	Subsegment Absorbed				
Interstation Control Wiring Renewal	0.58	0.15	-0.13	0.27	0.43	Subsegment Completed				
Total	**4.7**	**3.1**	**5.1**	**6.5**	**8.8**	**11.9**	**12.1**	**13.5**	**13.1**	**14.2**

[20] *Ibid.*

[21] Note: Relay Renewal has absorbed the cost and scope of work of "Pilot-wire Protection Renewal" from the 2020-2024 Rate Custom Incentive Risk Application.

During the 2025-2029 rate period, Toronto Hydro proposes to spend $64.70 million in its Control and Monitoring segment to renew 19 TS RTUs, 14 MS RTUs, 121 TS Relays, and 130 MS Relays. Expenditures are increased due to several factors, including an increase in volume of work for relays due to the modernization driver, more work replacing TS RTUs which have higher unit costs than MS RTUs, and forecasted inflation. The majority of the 2025-2029 spend relates to Relay Renewal ($48.91 million). The remaining spend is planned RTU Renewal with most of the costs being for the TS RTU renewals.

For the 2020-2024 rate period, the majority of proposed spending is for RTU renewal at both TS, MS, and installing RTUs at stations without an existing RTU (which is now completed). The remaining forecasted spending is planned pilot-wire protection upgrades and Interstation Control Wiring Renewal. The subsegment for Interstation Control Wiring Renewal is planned to be absorbed with Relay Renewal after the 2020-2024 rate period since they are accompanied by electromechanical relays and supply Toronto Hydro's larger customers. This will also focus on upgrading electromechanical relays to digital relays along with the communication wire upgrades from copper to fiber. This change will allow for more reliable tracking and reporting on work that is completed.

1. RTU Renewal – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete 12 TS RTU and 48 MS RTU renewals for a total cost of $19.32 million. Table 45 below provides an annual breakdown of the units completed and proposed between 2020 to 2024.

Table 45: RTU Replacement - Historical Actual and Bridge Unit Volumes

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-2024
TS RTUs	2	2	2	1	5	12
MS RTUs	17	6	11	8	6	48
Expenditure ($M)	3.8	1.6	4.1	3.6	6.2	19.3

The 2020-2024 Filed Plan proposed to complete 11 TS RTU and 34 MS RTU renewals for a total cost of $15.4 million. Expenditures are forecasted to be overspent by $3.92 million while TS and MS RTU units are forecasted to be one unit above and 14 units above respective targets. The total breakdown of RTU type is forecasted to be: 31 MOSCAD, eight D20, ten DACSCAN, one NTU, and ten new RTUs. This results in a total of 33 percent more RTUs renewed while spending 25 percent more. The spending difference can mainly be attributed to doing a larger amount of RTUs at the MS which have a much lower unit cost than at the TS.

a. <u>TS RTU Renewals</u>

The TS System consists of nine different RTUs being SEL 2240, SEL 3530, SEL 3355, D20MX, DACSCAN (obsolete), D20ME (obsolete), ACS NTU (obsolete), ABB COM 500 (obsolete), and SEL 3332 (obsolete).

Toronto Hydro plans to replace a total of 12 TS RTUs during the 2020-2024 rate period for a forecasted total of $7.99 million.

b. <u>MS RTU Renewals</u>

The MS System consists of eight different RTUs being SEL 2240, SEL 3530, D20MX, DACSAN (obsolete), D20ME (obsolete), ACS NTU (obsolete), MOSCAD (obsolete), and SEL 2032 (obsolete).

Toronto Hydro plans to replace or add a total of 48 MS RTUs during the 2020-2024 rate period for a forecasted total of $11.32 million.

2. RTU Renewal – 2025-2029 Expenditure Plan

Over the 2025-2029 period, Toronto Hydro plans to complete 19 TS RTU and 14 MS RTU renewals for a total cost of $15.79 million. Table 46 below provides an annual breakdown of the units proposed between 2025 to 2029.

Table 46: RTU Replacement - Forecast Unit Volumes

	Forecast					Total
	2025	**2026**	**2027**	**2028**	**2029**	**2025-2029**
TS RTUs	4	3	4	4	4	19
MS RTUs	2	3	3	3	3	14
Expenditure ($M)	2.8	3.1	3.2	3.3	3.4	15.8

The RTU Renewal subsegment is mainly prioritized according to the failure risks and outage impacts on customers. However, modernization has been incorporated to include upgrading assets that are obsolete. Stations with a larger number of customers, larger loads, and at higher risk of asset failure will be given higher priority compared to stations with lower number of customers, loads, and lower failure risks. Priority of replacements is assessed qualitatively by evaluating various factors as shown below:

Table 47: Control and Monitoring RTU Renewal Prioritization

Factor	Prioritization
Age	The older the asset, the higher the priority is assigned.
Number of Customers	The larger number of customers connected to the asset, the higher the priority.
Load	The larger amount of load (MVA), the higher the priority.
Failure rate	Assets at stations with higher incident of failures/repairs will have higher priority.
Switchgear Renewal Planned	Stations with switchgear renewals being planned do not need any of their assets to be replaced since the work is assumed to be done along with the switchgear.
Voltage conversion planned	Stations with voltage conversion being planned do not need any of their assets to be replaced.
Modernization	Assets that are driven by modernization while important will have the lowest priority since failure risk is the highest priority of the portfolio.

a. TS RTU Renewals

For the 2025-2029 rate period, Toronto Hydro plans to increase the rate of RTU renewals at the TS level to keep up with the amount of aging and obsolete RTUs for a total of 19 TS RTUs for a forecasted total of $11.12 million.

The associated costs have been estimated by a combination of historical costs of TS RTU renewals on a per switchgear or bus pair level, as well as considering future expected costs for General Alarm Cabinets. The alarm cabinets will need to be replaced along with some RTU renewals to allow the communication of alarms such as batteries, fire suppression, etc. which would not run to newly replaced RTUs.

b. MS RTU Renewals

For the 2025-2029 rate period, Toronto Hydro plans to reduce the rate of RTU renewals at the MS level for a total of 14 MS RTUs for a forecasted total of $4.66 million.

The associated costs have been estimated by historical costs of MS RTU renewals on a per station level. The original cost estimates for RTUs was broken down based off RTU type, however the distinction between station type seems to be the better factor for estimating unit costs. The overall cost increase is mainly due to assumed inflation.

3. Relay Renewal – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to upgrade or renew 46 relays for a total cost of $7.67 million. Table 48 below provides an annual breakdown of the units completed and proposed between 2020 to 2024.

Table 48: Relay Renewal - Historical Actual and Bridge Unit Volumes

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-2024
TS Relays	2	4	0	19	21	46
MS Relays	NEW SUBSEGMENT					0
Expenditure ($M)	0.36	1.4	1.1	2.6	2.2	7.7

For 2020-2024, Toronto Hydro initially planned to complete ten TS relay renewals (initially number given per customer as five, but assuming two relays per customer its now shown as ten) and 0 MS Relays with a planned spend of $3.5 million. The current plan for 2020-2024 is to complete 46 TS Relays (37 being Pilot Wire/Transfer Trip relays for 18 locations, the rest being URD feeder relay upgrades to digital) and 0 MS RTUs with a planned spend of $7.67 million. This results in a total of 460 percent more relays renewed while spending 119 percent more. This increase in relays with less spend is mainly due to the unit cost of Pilot Wire Renewals seeming to originally include copper renewal costs within the estimate. Also, since this was a newer segment and the costs were more unknown and as such better estimates are being developed as more projects are completed.

4. Relay Renewal – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro plans to upgrade or renew 251 relays for a total cost of $48.91 million. Table 49 below provides an annual breakdown of the units completed and proposed between 2025 to 2029.

Table 49: Relay Renewal - Forecast Unit Volumes

	Forecast					Total
	2025	**2026**	**2027**	**2028**	**2029**	**2025-2029**
TS Relays	18	21	22	17	22	100
Pilot Wire Relay	6	2	3	3	0	14
Transfer Trip Relay	2	1	1	2	1	7
MS Relays	19	23	26	27	35	130
Expenditure ($M)	9.1	9.1	10.3	9.8	10.7	48.9

Toronto Hydro plans to increase the work on relays during the 2025-2029 rate period to modernize the system from obsolete electromechanical relays to digital relays, as well as upgrade remaining Pilot Wire and Transfer Trip Relays to Fiber. In total, 121 TS and 130 MS relays are proposed for an estimated total of $48.91 million.

The Relay Renewal subsegment is mainly prioritized according to the modernization to upgrade electromechanical relays to digital relays. Stations with larger number of customers, larger loads, and at higher risk of asset failure will be given higher priority compared to stations with lower number of customers, loads, and lower failure risks. Priority of replacements is assessed qualitatively by evaluating various factors as shown below:

Table 50: Control and Monitoring Relay Renewal Prioritization

Factor	Prioritization
Modernization	Assets that are driven by modernization while important will have the lowest priority since failure risk is the highest priority of the portfolio.
Number of Customers	The larger number of customers connected to the asset, the higher the priority.
Load	The larger amount of load (MVA), the higher the priority.
Failure rate	Assets at stations with higher incident of failures/repairs will have higher priority.
Switchgear Renewal Planned	Stations with switchgear renewals being planned do not need any of their assets to be replaced since the work is assumed to be done along with the switchgear.
Voltage conversion planned	Stations with voltage conversion being planned do not need any of their assets to be replaced.

a. TS Relay Renewals

The TS Relays will focus on modernizing the relays to renew the obsolete Electromechanical Relays with Digital Relays. The TS Relays can be broken down into four categories being:

- TS Electromechanical to Digital Relay Renewal
  - Toronto Hydro is prioritizing modernizing the system from obsolete electromechanical relays to digital relays.
  - Toronto Hydro plans to replace a total of 100 of these Relays for an estimated $25.33 million.
- TS Digital Relay Renewal
  - Toronto Hydro will prioritize renewing existing digital relays that are either past their typical useful life or have obsolete relays that have been having known failures or are no longer available by the manufacture.
  - Toronto Hydro currently does not have any plans for these Relays in the 2025-2029 rate period and plans to begin like-for-like digital relay renewals in the next period of 2030-2034.
- Pilot-Wire Relay Renewal
  - Toronto Hydro is prioritizing renewing existing Pilot-Wire Protection Systems that have either copper communications or electromechanical relays to both avoid failure risk on the copper cables to replace with fiber, and to upgrade the customers with Pilot-Wire Protection Systems to the new standards.
  - These upgrades are also required to facilitate a transfer from an older switchgear to a new switchgear renewal, so proactively replacing these units will also help with TS Switchgear Renewals in the future to take a little less time.
  - Toronto Hydro plans to replace a total of five locations with 14 Relays for an estimated $4.77 million. This will complete the remaining copper cables and electromechanical relays suppling these customers.
- Transfer Trip Relay Renewal
  - Toronto Hydro is prioritizing renewing existing Transfer Trip Protection Systems that have either copper communications or electromechanical relays to both avoid failure risk on the copper cables to replace with fiber, and to upgrade the customers with Transfer Trip Protection Systems to the new standards.

- Toronto Hydro plans to replace a total of 6 locations with 7 Relays for an estimated $4.01 million. This will complete the remaining copper cables and electromechanical relays suppling these customers.

The priority of this work will focus on the Pilot-Wire and Transfer Trip Relays since they supply larger customers who prioritize reliability in their supply. These systems are also the most at risk of faults since they still have older copper communication cables versus fiber. The remaining TS Relay upgrades will focus on obsolete electromechanical relay to digital renewals to modernize the system.

The associated costs have been estimated by a combination of historical average costs of other TS Relay renewals on a per cell basis as well as taking the newer and higher estimates for 2023-2024 work.

b. MS Relay Renewals

For the 2025-2029 rate period, the MS Relays will focus on modernizing the relays to renew the obsolete Electromechanical Relays with Digital Relays. Similarly to the TS Relays, ideally the plans would include replacing existing digital relays that are more at risk to failure than electromechanical. However, as digital relays are newer to the system, Toronto Hydro does not estimate many will need to be replaced and if existing MS digital relays require renewal, it would take priority over electromechanical relays. The MS Relays can be broken down into two categories:

- MS Electromechanical to Digital Relay Renewal
  - Toronto Hydro is prioritizing modernizing the system from obsolete electromechanical relays to digital relays.
  - Toronto Hydro plans to replace a total of 130 of these relays for an estimated $14.80 million.
- MS Digital Relay Renewal
  - Toronto Hydro will prioritize renewing existing digital relays that are either past their typical useful life or have obsolete relays that have been having known failures or are no longer available by the manufacture.
  - Toronto Hydro currently does not have any plans for these relays in the 2025-2029 rate period and plans to begin like-for-like digital relay renewals in the next period of 2030-2034.

The associated costs for MS Relay Renewals have been estimated by a high-level estimation taking MS RTU renewal estimates and TS Relay renewal estimates and trying to determine a fair estimate on a per relay basis. Since this is a newer program, the unit costs are still not very well defined.

5. Interstation Control Wiring Renewal – 2020-2024 Variance Analysis

In the 2020-2024 rate period, Toronto Hydro initially planned to do 45km of Copper Wiring Renewals with a planned spend of $3.1 million. The current plan for 2020-2024 as shown in Table 51 below, is to complete 13km of Copper Wiring Renewals with a planned spend of $1.30 million. This results in a total of 71 percent less distance of copper renewals while spending 58 percent less. As a result of the novelty of this segment and considering Toronto Hydro had not previously performed planned replacement of its interstation control wiring, the costs were originally forecasted to be approximately $70k/km. However, based on projects executed during the 2020-2022 period, Toronto Hydro is revising its unit cost to $100k/km. This subsegment is planned to be completed by 2024 since there should be no more copper communications between stations.

Table 51: 2020-2024 Copper Renewal Plans

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-2024
Copper Renewal (km)	3	1	2	6	1	13
Expenditures ($M)	0.58	0.14	-0.13	0.27	0.43	1.3

6. Interstation Control Wiring Renewal – 2025-2029 Expenditure Plan

As shown in Table 52 below, Toronto Hydro expects to complete the requirement of Interstation Control Wiring Renewal from copper to fiber in 2020-2024. While copper communications wires still exist on the system, it should only exist from station to customer which will be addressed in the Relay Renewal program under sub-section E6.6.4.3 above.

Table 52: 2025-2029 Copper Renewal Plans

	Forecast					Total
	2025	2026	2027	2028	2029	2025-2029
Copper Renewal (km)	Subsegment Completed					
Expenditure ($M)	Subsegment Completed					

E6.6.4.4 Battery and Ancillary System Expenditure Plan

As shown in Table 53 below, Toronto Hydro forecasts to spend $7.3 million during the 2020-2024 rate period in its Battery and Ancillary System segment which is aligned to the 2020-2024 Battery & Ancillary system plan of $7.1 million. This spend is expected to be of $4.55 million and $2.75 million respectively for batteries/chargers and other ancillary projects. Toronto hydro forecasts to complete 37 fewer Battery and Chargers and three fewer Ancillaries (SST, AC Panel, Sump pump, Air compressor). Variance analysis for each subsegment is provided in the following subsections.

Table 53: Battery and Ancillary Systems Historical & Forecast Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Battery and Charger Renewal	1.0	0.53	0.61	1.9	0.52	0.82	0.71	0.94	0.84	0.80
Other Ancillary Renewal	0.91	0.70	0.49	0.35	0.30	2.4	1.5	0.99	2.6	2.1
Total	**1.9**	**1.2**	**1.1**	**2.2**	**0.8**	**3.2**	**2.2**	**1.9**	**3.4**	**2.9**

During the 2025-2029 rate period, Toronto Hydro proposes to spend $13.6 million in its Battery and Ancillary System segment and complete 63 battery and charger projects, and 11 ancillary projects. The budget of Battery and Charger Renewal has remained relatively similar to the budget approved for the 2020-2024 rate period. However, the cost of the SST and Other Ancillary Renewal have gone up due to two major factors: revised cost of installing Sum Pump and the renewal work required for AC Panels in Downtown TS.

The battery and ancillary systems at Toronto Hydro TS are prioritized above the same assets at MS due to the sheer volume of customers that are served through each TS. A TS asset failure affects significantly more customers than the same asset failing at an MS. Also, recent survey results have shown that the customer needs can be categorized into two main categories which are Rates and

Reliability. The 2025-2029 expenditure plan proposes a plan that looks to minimize the system risk while also maximizing the value of each project.

1. Battery and Charger Renewal – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete 46 MS and ten TS batteries, 39 MS and two TS charger systems for a total cost $4.55 million. Table 54 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 rate period.

Table 54: Battery and Charger Renewal - Historical Actual and Bridge and Unit Volumes

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Battery units	16	8	10	18	4	56
Charger units	15	8	8	9	1	41
Expenditures($M)	1.0	0.53	0.61	1.9	0.52	4.6

The 2020-2024 Filed Plan proposed 60 MS Batteries, 7 TS batteries, 60 MS chargers, and 7 TS Chargers for a total cost of $4.8 million. Therefore, expenditures are forecasted to be underspent by $0.25 million while unit volume is generally forecasted to be below target. Unit variances are respectively: -14, +3, -21, and -5.

Forecasted unit volume is below target, due the following:

- These include a higher unit cost for the replacement of TS batteries relative to the cost of MS batteries. Therefore, as a result of a higher volume of TS battery replacements, Toronto Hydro replaced fewer MS batteries.
- A number of MS batteries and chargers were replaced reactively during the 2020-2022 period.
- As a part of the work done, Toronto Hydro assessed whether it was necessary to replace batteries and chargers together. However, given the fact that the useful life of chargers is much longer than the batteries, Toronto Hydro decided to only replace the batteries if the charger has not reached its useful life in order to be cost-effective.

In addition, the overspend on stations ancillary renewal caused limitation to the DC battery renewal budget. All the factors explained above contributed to the under attainment for both batteries and charger systems.

2. Battery and Charger Renewal – 2025-2029 Expenditure plan

Over the 2025-2029 rate period, Toronto Hydro proposes to replace 55 end-of-life batteries and eight charger systems. The forecasted cost to complete this work is $4.12 million. Table 55 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 55 : Battery and Charger Renewal – Forecast Unit Volumes

	Forecast					Total
	2025	2026	2027	2028	2029	2025-29
MS Batteries	8	6	9	8	8	39
TS Batteries	4	3	3	3	3	16
MS Charger Systems	1	2	1	2	1	7
TS Charger Systems	-	-	1	-	-	1
Expenditures($M)	0.82	0.71	0.94	0.84	0.80	4.1

To complete the proposed 55 batteries and eight charger systems, Toronto Hydro forecasts a cost of $4.12 million over the 2025-2029 rate period. This forecast was developed based on project-level estimates for the proposed replacements, and average unit costs of: of $0.041 million per MS battery, $0.12 million per TS battery, $0.06 million per MS charger, and $0.15 million per TS charger. Unit costs were informed by actual and forecasted project costs over the 2020-2024 rate period.

Toronto Hydro prioritizes the replacement of its battery and charger systems based on the failure risk and impact posed by each system. The failure risk is assessed qualitatively by considering the following factors.

Table 56: Battery and Charger Prioritization

Factor	Prioritization
Age	Older battery and charger systems are given higher priority.
Number of Customers	The larger the number of customers connected to the station, the higher the priority (e.g. battery and charger systems located at Transformer Stations are given higher priority than those located at Municipal Stations).
Other factors determined on a case-by-case basis	Systems which are non-standard or contain obsolescent technology are given higher priority (e.g. some DC distribution

Factor	Prioritization
	panels are obsolete). Spare parts that should be accessible routinely are no longer available (e.g. DC panel breaker).
Voltage conversion planned (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets replaced.

3. Ancillary Renewal – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete zero air compressors, one sump pump, four SSTs, two carry-over SST, and one carry-over AC panel from the 2015-2019 rate period, for a total cost of $2.75 million. The carry-over projects incurred expenditures of $0.4 million over the 2020-2024 rate period.

Table 57 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 rate period.

Table 57: Ancillary Renewal - Historical Actual and Bridge Units

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-2024
Air Compressor Replacements	-	-	-	-	-	-
Sump Pump Installations	-	1	-	-	-	1
SST	3	0	1	1	1	6
AC Panels	1	0	0	0	0	1
Expenditures($M)	0.91	0.70	0.49	0.35	0.30	2.8

The 2020-2024 Filed Plan proposed two air compressors, three sump pumps, six SSTs and zero AC panels for a total cost of $2.3 million, and therefore expenditures are forecasted to be aligned while completing fewer units overall. Unit variances are respectively: -2, -2, -2, and +1. Forecasted unit volume is below target, because of multiple factors such as reactive replacements and under estimation of unit costs. However, the major factor of the cost variance is due to the higher unit cost of sump pump installations. Variance analyses for each subsegment are provided in the following subsections.

Air compressors: During the 2020-2024 rate period, the two planned projects were not required as one was replaced reactively and the other was sold to a third party.

Sump Pump Installation: For the 2020-2024 rate period, the plan was to install three sump pumps. Initially, it was determined that no extra civil work is required on site, however after site investigation it was established that there is no existing system in place. As a result, the scope will need to include all the required civil work for the new system installation. This created variance in the project where total budget for sump pumps was $0.2 million and the one project that was completed cost $1.0 million. Toronto Hydro prioritized installing the Cecil TS sump pump since it has many major assets in the basement that would be vulnerable if flooding occurs.

SST: The 2020-2024 Filed Plan proposed six SST renewals for a total cost of $1.9M. One of the SSTs at Dufferin TS was replaced reactively and upon further assessment the SST renewal project at Windsor TS was no longer required. This resulted in two fewer SST replacements.

Overall, Toronto Hydro forecasts to spend $2.0 million on SST replacements. In addition, George & Duke SST renewal was a carryover from the 2015-2019 rate period. This project included replacement of one SSTs and one AC panel. This carryover project incurred expenditure of $0.4 million over the 2020-2024 rate period. This results in a forecasted net expenditure of $1.6M for the four SST renewal projects, and average unit cost of $0.4 million.

As a result, the forecasted unit cost over 2020-2024 has slightly increased from the unit cost provided in the 2020-2024 rate application period. The main factor driving the increase is that Toronto Hydro did not have actual costs or experience executing this work to base its estimates on, as SST renewal was a newer segment in the last rate application period.

4. Ancillary Renewal – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro proposes to install three sump pumps, and replace three SSTs, and five AC panels. The forecasted cost to complete this work is $9.52 million.

Table 58 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 58: Ancillary Renewal - Historical Actual, Bridge and Forecast Units

	Forecast					Total
	2025	2026	2027	2028	2029	2025-29
Sump Pump Installations	1	-	-	1	1	3
SST	1	1	0	1	0	3
AC Panels	1	1	1	1	1	5
Expenditure ($M)	2.4	1.5	0.99	2.6	2.1	9.5

Sump Pump Installations: The utility has increasingly focused on storm hardening its system to ensure reliable power supply for its customers. After completing station risk assessments, Toronto Hydro is proposing $3.01 million for the installation of three sump pumps in 2025-2029.

SST: For the 2025-2029 rate period, Toronto Hydro is proposing $1.55M to replace three SSTs located at three of its 15 downtown TS. The slight increase in cost is driven by addition of the metering to the SST cell allowing for better load tracking and renewal foresight in the future.

Currently, Toronto Hydro does not monitor SST loads, and sizing has been based on theoretical values rather than actual loading data to reference. Furthermore, the cost increase is driven by increased unit costs in recent projects attributed mainly to civil requirements and higher labour requirements than originally estimated.

AC Panels: Based on the experience, the average unit cost of AC panel replacement is $0.99 million. Toronto Hydro is proposing $4.96 million for the installation of five AC panels over 2025-2029. It should be noted that the estimated cost is based only one AC panel replacement in the recent years, therefore Toronto Hydro expects cost variances until a number of these projects are completed.

Historically, AC panel replacements have not been completed. It was assumed that when needed, AC panel replacements would be absorbed into the scope of work of SST or charger renewals. However, an SST replacement at George & Duke MS revealed the complexity and true costs of AC panel replacements.

Toronto Hydro prioritizes the replacement of its ancillary systems based on the failure risk and impact posed by each system. The failure risk is assessed qualitatively by considering the following factors.

Table 59: Ancillary System Prioritization

Factor	Prioritization
Age	Older systems are given higher priority.
Failure Impact on a system-by-system basis	Systems that have more far reaching impacts are given higher priority. For example, AC Panel failure could render entire switchgears breakers inoperable, which could cascade into a larger system problem which has to be solved within the eight hours the DC system could provide, therefore replacing AC Panels will be given a higher priority compared to SSTs. On the other hand, basement flood would have a more immediate impact on the system compared to failure of an air compressor
Number of Customers	The larger the number of customers connected to the station, the higher the priority. For example, ancillary systems located at TS are given higher priority than those located at MS.
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets to be replaced

E6.6.5 Options Analysis

E6.6.5.1 Transformer Stations

The Sustainment Option is Toronto Hydro's proposed plan for the Transformer Stations segment over the 2025-2029 rate period, as presented in this document. This option was selected because it is best aligned with customer priorities: an equal balance on reliability and cost. As a result, the Sustainment Option is expected to maintain TS reliability given population demographics and System Health. In addition, two other options were considered: Improvement and Managed Deterioration. The outcome measures, units, and costs of each option are presented in Table 60 below.

Table 60: Transformer Stations Options – Measures, Units, and Costs

Outcome Measure		2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
APUL [%]	TS Switchgear	42	32	28	34
	Outdoor Breaker	13	8	8	13

Outcome Measure		2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
	Outdoor Switch	7	14	14	20
System Health (ACA) [%]	TS Switchgear	2	15	13	16
	Outdoor Breaker	5	12	12	19
Arc-Resistant TS Switchgear [%]	TS Switchgear	26	36	40	32
CIR Period		**2020-24**	**2025-29**	**2025-29**	**2025-29**
TS Switchgear		5	5	7	4
TS Outdoor Breaker		12	12	12	7
TS Outdoor Switches		69	63	63	49
Cost ($M)		95.2	134.1	168.1	112.2

The Improvement Option would replace an extra two TS switchgear with an additional cost of $34.0 million relative to the Sustainment Option. This option would ensure that population demographics meet or exceed those present over the 2020-2024 rate period. This is expected to result in higher system reliability, and would result in an improvement to all measures provided in Table 60. This option is not recommended because customers have indicated almost equal priority on cost and reliability. The Improvement Option favours reliability over cost, and therefore is not aligned with customer priorities.

The Managed Deterioration Option would replace one TS switchgear, five outdoor switchgear breakers and 14 disconnect switches less, resulting in 21.9 million decrease in spending compared to the Sustainment Option. The Managed Deterioration Option would result in more obsolete and old components remaining in the system, thereby marginally decreasing Toronto Hydro's reliability. In order to maintain Toronto Hydro's standards and align with industry standards, this option is not recommended.

E6.6.5.2 Municipal Stations

The Sustainment Option is Toronto Hydro's proposed plan for the Municipal Stations segment over the 2025-2029 rate period, as presented in this document. This Option was selected because it is best aligned with customer priorities: an equal balance of reliability and cost. As a result, the

Sustainment Option is expected to maintain MS reliability given population demographics and asset failure trends. In addition, two other options were considered: Improvement, and Managed Deterioration. The outcome measures, units, and costs of each Option are presented in Table 61 below.

Table 61: Municipal Stations Options – Measures, Units, and Costs

Outcome Measure	2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
APUL [%]	40	33	31	35
System Health (ACA) [%]	3	21	20	22
Arc-Resistant MS Switchgear [%]	22	37	40	35
Rate Application Period	**2020-24**	**2025-29**	**2025-29**	**2025-29**
MS Switchgear	10	12	15	10
Power Transformers	11	15	17	12
MS Primary Supplies	4	1	1	1
Cost ($M)	44.6	70.3	83.2	57.7

The Managed Deterioration Option would replace two fewer MS switchgear and three fewer power transformers with a cost reduction of $12.6 million relative to the Sustainment Option. The Managed Deterioration Option would result in an increase in the number of the oldest MS switchgear in service, and would maintain population demographics for the power transformers. This is expected to result in lower system reliability, especially given recent failure trends, and would result in a degradation to all measures provided in Table 61. This Option is not recommended because customers have indicated almost equal priority on cost and reliability. The Managed Deterioration Option is expected to reduce reliability, and therefore is not aligned with customer priorities.

The Improvement Option would replace three more MS switchgear and two more power transformers with a cost increase of $12.9 million relative to the Sustainment Option. The Improvement Option would result in equal or improved MS switchgear demographics, and would increase pacing in power transformer replacements to eliminate all units operating past 59 years by the end of 2034. This is expected to result in improved system reliability, and would result in an improvement to all measures provided in Table 61. This Option is not recommended because customers have indicated equal priority on cost and reliability. The Improvement Option is expected to improve reliability at significantly greater cost, and therefore is not aligned with customer priorities.

E6.6.5.3 Control and Monitoring

The Improvement Option is Toronto Hydro's proposed plan for the Control and Monitoring segment over the 2025-2029 rate period, as presented in this document. This Option was selected because it is best aligned with customer priorities: a balance between reliability and cost in terms of RTU Renewal with the addition of modernizing the grid from older obsolete electromechanical relays to digital relays for Relay Renewal. As a result, the Improvement Option is expected to maintain Control and Monitoring reliability given population demographics and asset failure / corrective work trends while also modernizing the grid to new digital relays. In addition, two other options were considered: Sustainment, and Managed Deterioration. The outcome measures, units, and costs of each Option are presented in Table 62 below.

Table 62: Control and Monitoring Stations Options – Measures, Units, and Costs

Outcome Measure	2024 Bridge	2029 Proposed – Improvement	2029 Alternative 1 – Sustainment	2029 Alternative 2 – Managed Deterioration
RTU APUL/Obsolete [%]	29%	0%	0%	6%
TS Relay APUL/Obsolete [%]	43%	21%	28%	28%
Digital Relays [%]	63%	90%	64%	64%
CIR Period	**2020-2024**	**2025-2029**	**2025-2029**	**2025-2029**
TS RTU	12	19	19	14
MS RTU	48	14	14	8
TS Relay	46	121	98	98
MS Relay	0	130	16	16
Cost ($M)	28.3	64.7	35.7	30.4

The Sustainment Option would focus on replacing both RTUs and digital relays (rather than electromechanical relays) that are obsolete or past their typical useful life, resulting in a cost reduction of $28.96 million. The Sustainment Option would also continue to upgrade pilot wire and transfer trip relay customers with copper communications to fiber and upgrade the relays from electromechanical to digital. This option would replace the same amount of RTUs, pilot wire relays, and transfer trip relays, however, this would still replace 21 electromechanical relays (pilot wire or transfer trip relays) and focus the remainder on the digital relays which are expected to be obsolete or past their typical useful life. For this option, it mainly focuses on the renewal portion of the portfolio rather than modernizing the system. While this option still seems like an improvement due to the continued improvement to the outage measures (other than Digital Relay percentage), the rate of replacement in terms of total RTUs is less than proposed last rate application and relays are now becoming more integrated into the portfolio so it should lower the amount of relays that are considered obsolete or past their typical useful life to a more reasonable percentage. In addition, these percentages also include the help of current planned Switchgear Renewals and MS Conversions. This option is not recommended because with an ever-growing need for modernization, digital relays can help provide a greater ability for control and monitoring Toronto Hydro distribution.

The Managed Deterioration Option is very similar to the Sustainment option, with the difference being to only replace RTUs that are past their typical useful life versus RTUs that are considered obsolete as well. This would result in a reduction from the proposed option of $34.33 million. This option is not recommended, since modernization and having the ability to control and monitor the system has become a high priority and is crucial for many of Toronto Hydro's operations.

E6.6.5.4 Battery and Ancillary Systems

The Sustainment Option is Toronto Hydro's proposed plan for the Battery and Ancillary segment over the 2025-2029 rate period, as presented in this document. This Option was selected because it is best aligned with customer priorities: an equal balance on reliability and cost. This option would reduce failure risks and provides positive outcome for customers by maintaining reliability. In addition, two other options were considered: Improvement, and Managed Deterioration. The outcome measures, units, and cost of each option are presented in Table 63 below.

Table 63 : Battery and Ancillary Systems – Measures, Units, and Costs

Outcome Measure	2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
Batteries APUL [%]	12%	9%	0%	14%
Charger Systems APUL [%]	7.5%	11%	1%	12%
SST APUL [%]	7%	0%	0%	2%
CIR Period	**2020-24**	**2025-29**	**2025-29**	**2025-29**
MS Batteries	46	39	53	32
TS Batteries	10	16	16	16

Outcome Measure	2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
MS Charger Systems	39	7	21	5
TS Charger Systems	2	1	1	1
Sump Pump	1	3	3	1
SST	6	3	3	2
AC Panel	1	5	5	3
Expenditure ($M)	7.3	13.6	15.1	8.8

The improvement Option would replace 14 more MS Batteries and 14 more MS Chargers with a cost increase of $1.42 million relative to the Sustainment Option. Overall, this option is expected to improve system reliability and replace almost all batteries and chargers which are past their useful life by 2029. This option is not recommended, because it does not align as well with customer priorities: an equal balance on reliability and cost.

The Managed Deterioration Option would replace seven fewer MS Batteries and two fewer MS Chargers, two fewer sump pumps, one less SST, and two fewer AC Panels at a cost reduction of $4.89 million relative to the Sustainment Option. This Option would permit an increase in APUL for Batteries and Charger Systems and SSTs. Also, for other ancillary systems, two AC panel renewals and two sump pump installations would be deferred to the next rate application period, which is expected to result in lower system reliability. This Option is not recommended because customers have indicated almost equal priority on cost and reliability.

E6.6.6 Execution Risks & Mitigation

Each segment of the Stations Renewal Program faces challenges which can delay or prevent planned renewal work from occurring. Many of these challenges overlap across the four segments of this Program. These challenges are summarized in the Table 64 below.

Table 64: Execution Risk Applicability by Segment

Segment	Execution Risks						
	Resource Constraints	Planned outages	Asset Failures	Procurement Lead Times	Project Assessment	Distribution Coordination	Other Risks
Transformer Stations	✓	✓	✓	✓	✓	✓	✓
Municipal Stations	✓	✓	✓	✓	✓	✓	✗
Control and Monitoring	✓	✓	✗	✓	✓	✗	✓
Battery and Ancillary Systems	✓	✓	✓	✓	✓	✗	✗

E6.6.6.1 Resource Constraints

All four segments of the Stations Renewal Program use the same pool of stations design and construction resources. Therefore, if there are insufficient resources to complete all the projects planned in the Program, then certain projects will need to be deferred to ensure highest priority projects are completed. Prioritization of projects within this Program is discussed in Section E6.6.3.4. Toronto Hydro is mitigating this risk with the help of third-party providers to complete any projects in excess of Toronto Hydro's resource capacity.

E6.6.6.2 Planned Outages

Most of the renewal work cannot be completed unless a planned outage is arranged. Planned outages are needed to de-energize feeders, power transformers, switchgear, or entire stations without causing power outages to customers, so that Toronto Hydro's crews can safely complete replacement or maintenance work. For Toronto Hydro to de-energize station assets without introducing any undue risk of power outages, Toronto Hydro cannot execute multiple planned outages within the same TS or at two neighbouring MS. Additionally, projects occurring at neighbouring MS are planned to take place in different years, and if possible, at least two years apart.

E6.6.6.3 Asset Failures

Failure of station assets are a source of unplanned station outages which can prevent replacement projects from proceeding due to lack of redundancy. This risk can be mitigated by proactively replacing end-of-life station assets in a timely manner as proposed in this Program.

E6.6.6.4 Procurement Lead Times

Procurement lead times for power transformers, MS switchgear, and TS switchgear range from six to 18 months. For this reason, it is difficult and sometimes infeasible to advance or expedite the replacement of a station asset, even if such a change in schedule would result in a more effective execution of the Program. To help mitigate this risk, Toronto Hydro orders this equipment six to 26 months or earlier in advance of expected in-service dates. In addition, with the planned renewal plan for relays, there is an added risk of procurement issues as there has been issues procuring relays recently. Currently, lead times are expected to be around four to five months but with the addition of so many additional planned digital relays, this may add additional complications with procurement.

E6.6.6.5 Distribution Coordination

Distribution coordination is a challenge commonly affecting the TS and MS segments. All TS switchgear replacement projects and all projects under the MS segment require a distribution project to support the replacement of station assets. A switchgear replacement requires distribution feeders to be removed from the old switchgear and connected to the new switchgear, and replacement of the primary cable within a MS is completed through a distribution project. As a result, if there are delays or resource constraints in the distribution projects, then dependent station projects may also be delayed. Similarly, distribution projects also require planned outages as discussed earlier.

To mitigate the risk relating to distribution coordination, Toronto Hydro engineers strive to clearly define the need for coordination between station and distribution projects at the inception of such projects. On this basis, project managers plan interdependent projects as a single entity so that adequate resources can be allocated and adequate outage planning can be initiated.

E6.6.6.6 Project Assessment

All planned work undergoes a risk assessment by Toronto Hydro’s control centre prior to execution. This timeframe is accounted for in the pacing outlined in Section E6.6.3.4.

E6.6.6.7 Other Risks

The risks identified below apply only to their specific segments.

1. Hydro One Coordination (TS)

One of the most significant risks for the successful completion of projects under the TS segment will be Toronto Hydro's ability to effectively coordinate with Hydro One. For example, when replacing a TS switchgear, close coordination is required to transfer Hydro One's supplying transformers from the existing switchgear to the new switchgear. For TS outdoor breaker replacements, all protection and control wiring needs to be verified by Hydro One prior to the breakers being placed back in-service.

With this need for coordination, there is always a risk Hydro One might not be able to secure resources to align with Toronto Hydro's work plan. Additionally, similar to the discussion in Section E6.6.6.2, Hydro One also requires that its own equipment undergo planned outages. Given the need for such planned outages, there is a risk that Toronto Hydro's replacement work will be prevented from proceeding due to a lack of redundancy.

Toronto Hydro mitigates this risk by sharing its high-level replacement plans with Hydro One years in advance of planned project start date. As project execution draws closer, Toronto Hydro and Hydro One exchange detailed information and communicate more frequently to ensure that work plans and resourcing aligns for both companies. For more information, see Exhibit 2B, Section B.

2. Physical Constraints (TS)

Space limitations pose a significant risk to the timely completion of TS switchgear renewal projects under the TS segment. In many cases, Toronto Hydro stations do not have space available to install new switchgear. This is a problem because it is usually necessary to install a new switchgear before decommissioning the existing unit, so as to maintain continuous power supply to customers.

The alternative to this approach is to transfer all customers from the existing switchgear to an adjacent switchgear, decommission the existing switchgear, and then install the replacement in the same space. This can only be done if the adjacent switchgear has enough spare capacity to supply these additional customers. Spare capacity on this order is seldom available.

Toronto Hydro mitigates this risk through use of its Station Expansion Program, which is intended to ensure capacity requirements are met on the distribution system.[22] For example, replacement of the Windsor TS A3-4WR switchgear unit will be possible once Windsor A19-20WR been energized,

[22] Exhibit 2B, Schedule E7.4.

following which the electrical load on the Windsor TS A3-4WR switchgear will be transferred to the new A19-20WR switchgear. A19-20 can only be energized with Hydro One T1/T3 after Hydro One replaces their transformers T5/T6 in Q2 2025. Thereafter, A3-4WR can be decommissioned and its space used to install a new switchgear – A21-22WR. This in turn will allow capacity for the next Windsor TS switchgear unit to be replaced.

In the case of TS building not having enough space to install a new switchgear, a new building or renovation for an existing building is required to facilitate the switchgear replacement. However, this solution requires a long-term plan since the construction of the building may take few years to be ready for switchgear installation. Toronto Hydro plans to request Hydro One to refurbish Hydro One owned building for the new switchgear installation at Bridgman TS.

Due to the lack of space at TS in Downtown, it is impossible to expand the building or is very costly to do so. Small footprint switchgear is necessary for limited space in the TS residing in the Downtown area. Pursing the cost-effective switchgear with narrow feeder cell will be only way to implement switchgear replacement in some TS, like Cecil, Charles, Duplex and Windsor.

By ensuring a reasonable level of spare capacity at or adjacent to heavily loaded stations, Toronto Hydro will be able to effectively plan and execute switchgear replacement while accommodating new customer connections.

3. Customer Coordination (Control and Monitoring)

For pilot-wire system replacements under the Control and Monitoring segment, a challenge to successful execution is customer coordination. Such replacements require customer relays and associated equipment to be replaced in parallel with Toronto Hydro's equipment. This introduces a risk since projects cannot be scheduled until a time is found which satisfies both the customer's and Toronto Hydro's needs. Toronto Hydro minimizes this risk by informing customers several months ahead of planned work, allowing sufficient time for customers to respond and schedule a time that is feasible.

E6.7 Reactive and Corrective Capital

E6.7.1 Overview

Table 1: Reactive and Corrective Capital Program Summary

2020-2024 Cost ($M): 297.6	**2025-2029 Cost ($M):** 328.1[1]
Segments: Reactive Capital; Worst Performing Feeders	
Trigger Driver: Failure	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Environment and Customer Focus	

The Reactive and Corrective Capital program (the "Program") addresses the replacement of failed and defective major assets, and provides for near-term corrective actions on Toronto Hydro's least reliable feeders. The work required under this Program is unplanned, unpredictable, and non-discretionary. Toronto Hydro carries out the projects and activities in this Program in response to:

- Major asset failures;
- High risk asset deficiencies discovered through planned inspection or in the course of day-to-day work; and
- Feeders exhibiting especially poor reliability.

The Program is grouped into two segments summarized below, and is a continuation of the reactive and corrective activities described in Toronto Hydro's 2020-2024 Distribution System Plan.[2]

- **Reactive Capital:** This segment covers the non-discretionary replacement of failed or failing major assets across the entire system. There are a significant number of asset failures each year. Between 2018 and 2022, on average, there were over 825 Customer Interruptions ("CI") and over 678 Customer Hours Interrupted ("CHI") associated with each major asset failure across the network. Catastrophic failures of assets can require very large investments by Toronto Hydro which, in the absence of a dedicated reactive capital budget, would deprive other programs of necessary resources to maintain the grid. The objective of this segment is to manage unexpected asset failures and address high-risk deficiencies (or assets

[1] Consistent with the 2020-2024 program, the 2025-2029 program forecast includes allowances for streetlight reactive pole replacement, reactive streetlight replacement and streetlight spot improvement.
[2] EB-2018-0165, Exhibit 2B, Section E6.7

approaching imminent failure) in a timely and cost-effective manner. Toronto Hydro's goal is to mitigate the impact of failures on customer outcomes such as reliability, safety, and the environment for 2025 to 2029 and beyond.

- **Worst Performing Feeders:** The Worst Performing Feeder ("WPF") segment focuses on improving overall service reliability for customers supplied from poorly performing feeders. The objective of this segment is to identify feeders performing poorly over a rolling 12-month period and perform work in an effort to mitigate further interruptions. Toronto Hydro defines a feeder as performing poorly when it meets, or is trending towards meeting, the following criteria:
  - Feeders (with no large customers) at risk of experiencing seven or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of 7 or more, or "FESI-7");
  - Key Account ("KA") feeders at risk of experiencing six or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of 6 or more, or "FESI-6 Large Customer"); or
  - Feeders (KA or non-KA) that are experiencing systemic issues in a localized area that are resulting in, or are at risk of resulting in, multiple sustained or momentary interruptions.

  Toronto Hydro has also started tracking a new metric called Customers Experiencing Multiple Sustained or Momentary Interruptions of 10 or more ("CEMSMI-10") to put additional focus on large critical customers with Ion meters who are experiencing poor reliability (including power quality) that negatively impacts their operations. These customers are typically large manufacturing facilities or hospitals, which are sensitive to voltage sags and momentary outages.

  Poorly performing feeders that are designated FESI-7 or FESI-6 Large Customer have a disproportionately negative impact on the system's overall reliability performance, as reflected in metrics such as the annual CI and CHI. In an effort to effectively manage these metrics and the impact on customer, outages are analyzed on poorly performing feeders and targeted work is issued.

As the nature of work in this Program is largely unplanned, unpredictable, and can vary significantly from year to year, Toronto Hydro has based its 2025-2029 forecast costs and projected reactive work volumes for this Program on historical trends and asset condition demographics. The utility forecasts $328.1 million for the Program during the 2025-2029 rate period, which is approximately 10 percent higher than projected for 2020-2024. Timely reactive work improves safety, avoids depriving other capital programs of planned resources, mitigates environmental impacts and public safety risks, and reduces strain on the distribution system.

E6.7.2 Outcomes and Measures

Table 2: Reactive and Corrective Capital Program Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, FESI-6 Large Customer, System Health Index) by: ○ Promptly replacing major assets that have failed or are at a very high risk of near-term failure; ○ Monitoring feeders that are at a high risk of becoming FESI-7 or FESI-6 Large Customer, and taking near-term mitigating actions where feasible.
Operational Effectiveness - Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency (TRIF) measure and safety objectives (including compliance with Ontario Regulation 22/04) by: ○ Replacing failed major assets or assets approaching imminent failure to mitigate the risk of catastrophic asset failure causing injuries to utility employees and/or members of the public.
Environment	• Contributes to reducing environmental impact of Toronto Hydro's distribution system by: ○ Reducing the potential for release of harmful chemicals, smoke, or waste (e.g. oil leaks, SF6 gas) into the environment through timely replacement of failing or failed major assets. ○ Improving Toronto Hydro's Spills of Oil containing PCBs measure and reduce the risk of toxic exposure to the environment by eliminating PILC cable and AILC cable containing asbestos and/or lead.

Customer Focus	• Contributes to Toronto Hydro's customer service obligations and objectives by: ○ Ensuring the accurate billing of all smart metered customers based on actual usage by restoring metering service as soon as possible. ○ Supporting compliance with the Electricity and Gas Inspection Act and the Weights and Measures Act.

E6.7.3 Drivers and Need

Table 3: Reactive and Corrective Capital Program Drivers

Trigger Driver	Failure
Secondary Driver(s)	Reliability, Safety, and Environmental Risk

The Reactive and Corrective Capital program is largely driven by the need to address equipment failure. The Program is focused on ensuring asset and system performance at an acceptable standard by:

- Addressing asset deficiencies and failures through like-for-like replacements;
- Completing short-term and small-scale replacements to reduce safety and environmental risks; and
- Executing short term, targeted, and small-scale mitigation measures to reduce the risk of additional outages on feeders exhibiting poor reliability outcomes.

The needs underlying the Reactive Capital segment must be addressed in short order mainly due to asset failure risk. The Worst Performing Feeders segment mainly aims to improve overall service reliability for customers supplied from poorly performing feeders.

Through the Program, Toronto Hydro will be better able to maintain system performance and reliability, manage or eliminate safety risks to the public and Toronto Hydro employees, and ensure customer satisfaction. The trigger and secondary drivers for this Program are discussed below.

E6.7.3.1 Failure Risk

Asset failure on Toronto Hydro's distribution system presents reliability risks which can lead to outages and directly impact customers, environmental risks such as oil spills, and safety risks such as arc flashes, and potentially catastrophic fires. These aspects are discussed in more detail in the following sub-sections. Additionally, timely replacement of failed equipment may be required to avoid operating the distribution system under contingency conditions (i.e. with a lack of feeders or assets that can provide backup supply in the event of a subsequent equipment failure).

Various factors can cause failure, including degradation of an asset's condition, foreign interference, and weather (e.g. major storms). For example: a fractured pole caused by a vehicle accident (i.e. foreign interference); or structural deficiencies of an underground vault as a result of gradual degradation. See Figures 1 and 2 below for reference.

Figure 1: Pole struck by vehicle identified through a patrol

Figure 2: Underground vault structural deficiencies

Age and condition can also affect the health of an asset, and contribute to asset failure. With a higher number of end-of-life assets in the system there is a greater likelihood of failure and need for reactive replacement. Toronto Hydro performs Asset Condition Assessments ("ACA") on many of its major asset classes. The System Health – Asset Condition for a major asset is ranked from HI1 to HI5 where HI5 indicates the worst condition. Table 4 below shows the percentage of combined HI4 and HI5 populations of major assets divided by their total populations. Wood poles represent the highest number of HI4 and HI5 assets out of the total at risk asset population (e.g. 9,628 in the distribution system) which will continue to drive expenditures in this Program.

Table 4: Proportion of Assets in HI4 & HI5 by Major Asset

Major Assets	2022 Total # of Assets Breakdown		
	Total Assets per Asset Class	Current Health Score 2022 Data	
		HI4 & HI5	% HI4 & HI5
Wood Pole	106,386	9,628	9%
Cable Chamber	10,657	592	6%
Vault Transformer	11,497	258	2%
Submersible Transformer	9,161	180	2%
Padmounted Transformer	7,011	257	3%
Network Vault	470	91	19%
Network Protector	1,728	42	2%
Network Transformer	1,718	43	3%
Total	**148,628**	**11,073**	**7%**

In addition to assessing current condition, Toronto Hydro projects future asset condition for the same assets. As an example, Table 5 summarizes Toronto Hydro's ACA results for underground submersible transformers, which indicate:

- 180 submersible transformers exhibit material deterioration (HI4 & HI5) and should be considered for replacement as of end of 2022;
- Without any intervention, the number of transformers exhibiting material deterioration is forecasted to more than double by 2029.

Table 5: Asset Condition for Submersible Transformers[3]

Condition	Submersible Transformers	
	2022	2029

[3] For more details on Asset Condition Assessment see Exhibit 2B, Section D1 – Asset Management Process Overview.

HI1 - New or Good Condition	8,120	7,330
HI2 – Minor Deterioration	699	642
HI3 – Moderate Deterioration	162	635
HI4 – Material Deterioration	133	240
HI5 – End of Serviceable Life	47	314
Total	**9,161**	**9,161**

Detailed discussions of the condition and age demographics of various asset classes are provided under Toronto Hydro's System Renewal programs.[4]

1. Reliability

An important driver of the Program is system reliability. Depending on the asset and its location within the distribution system (e.g. Main trunk vs. laterals/sub-laterals), the impact may vary from ten customers experiencing an outage to thousands of customers on the main trunk. Asset failures affect the supply of power to Toronto Hydro's customers (e.g. key account customers, residential and/or industrial) and the additional fault current and switching surges create strain on the system that can lead to cascading failures or reduced expected life of other major assets. Historical system reliability impacts are discussed in detail further below.

Figure 3 below shows the causes of sustained interruptions between 2018 and 2022. The chart shows that 41 percent of all sustained interruptions are caused by defective equipment, which is significantly higher than all other causes. The Program focuses mainly on the mitigation of outages caused by major equipment failures; however, it can also mitigate interruptions by various other causes. For example, when replacing a failing overhead transformer, Toronto Hydro may fit the new transformer with an animal guard that may mitigate the "Animal Contact" cause as well as the "Defective Equipment" cause.

[4] Exhibit 2B, Section E6.

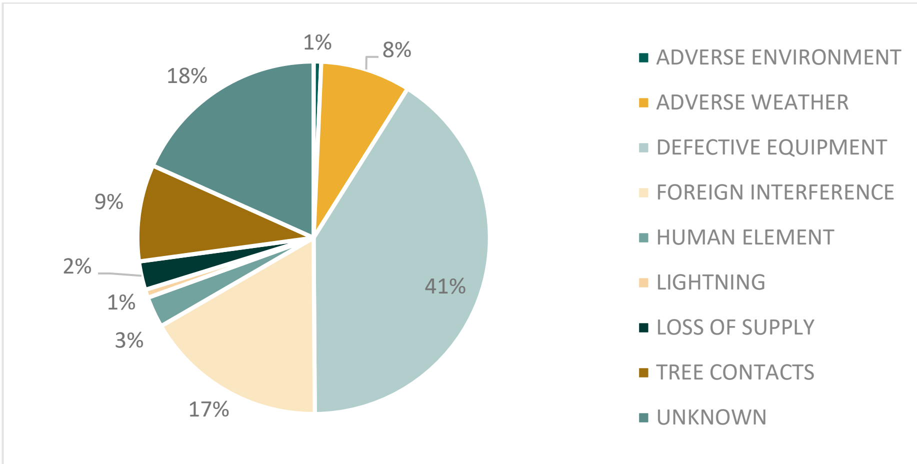


Figure 3: Causes of Sustained Feeder Outages between 2018 and 2022

Table 4 below shows the customer reliability impacts of major asset failures between 2018 and 2022. Each failure of an overhead switch between 2018 and 2022, for example, caused an average of 1,062 customers interruptions and 572 Customer Hours Interrupted. Timely replacement of equipment prior to its failure will mitigate the frequency and duration of interruptions experienced by customers.

Table 4: Average CI and CHI Associated with Failures of Major Assets from 2018 - 2022

Asset	Average Customers Interrupted (CI)	Average Customer Hours Interrupted (CHI)
Overhead Switches	1,062	572
Underground Switchgear	1,204	1,156
Overhead Transformers	115	122
Poles	1,159	673
Underground Cables	881	775
Underground Transformers	596	326

Through Phase 1 of Toronto Hydro's Customer Engagement, "Reliable Service" was identified as a top customer need, and ranked in the top three priorities for all customers, with reliable service being the top priority for key account customers.[5] Most notably, however, there is increasing demand for reliable service from smaller residential customers. A likely contributor to this trend is

[5] See Exhibit 1B, Tab 5, Schedule 1 – Customer Engagement; and Appendix A for Customer Engagement Report.

the transition to work-from-home for many employees at least part of the time, driven by the COVID-19 pandemic. Interruptions to many residential customers is no longer merely an inconvenience, but also impacting businesses through lost labour hours. This Program is intended to address this customer priority, among others, by issuing the necessary mitigation work to reduce the total number of outages and their duration.

2. Safety

Another important driver of the Program is the safety of both the public and Toronto Hydro employees. Failure modes of equipment, depending on their nature, can have immediate and serious safety or environmental consequences. For example, transformers in deteriorated condition may experience transformer fires or oil leaks. Similarly, overhead lines with damaged insulators may lead to tracking and potential pole fires which is a serious safety risk to workers and the public. Furthermore, civil deficiencies such as structural damage in underground assets can jeopardize the public and Toronto Hydro employees. The Reactive Capital segment mitigates safety risks by replacing assets that have failed or are approaching imminent failure. Figure 4 illustrates a pole fire (left) and hazardous civil conditions found in a network vault (right).

Figure 4: Pole fire caused by Tracking (left), Exposed and rusted rebar in Network Vault (right)

3. Environment

Finally, asset failures can also be harmful to the environment. Leaking oil-filled transformers, PILC cable splices, or SF6-insulated switchgear pose a serious environmental risk. Asset failures can also result in the release of harmful contaminants and greenhouse gases into the environment. Timely capital replacements help mitigate such environmental risks. The Reactive Capital segment addresses oil deficiencies by replacing leaking transformers. As an added benefit, during transformer replacement, assets that are at risk of containing PCB are also replaced, thereby reducing the possibility of oil spill containing PCBs and contributing to complete removal of all PCB transformers by 2025.

E6.7.3.2 Reactive Capital

The Reactive Capital segment is comprised of work relating to overhead, underground, secondary network, stations and metering assets. The purpose of this reactive work is to restore service to customers and maintain system reliability by addressing severe asset deficiencies and failures. Reactive work occurs on an unplanned basis in response to an asset failure or the detection of a high-risk asset deficiency (e.g. a severely cracked or rotten pole). Such issues cannot be addressed under planned capital renewal procedures and timelines, and therefore must be reactively replaced to maintain the safety and reliability of the distribution system. Reactive work is executed within a short timeframe (e.g. within 15 days to within six months, based on assigned priority level) following the detection of an asset requiring replacement. Reactive work covers Toronto Hydro's entire distribution system and affects all asset classes.

Asset deficiencies or substandard conditions across Toronto Hydro's distribution system are identified mainly through the Preventative and Predictive Maintenance programs, but can also be identified either during the normal course of operations or through the Emergency Response program, as shown in Figure 5. Identified deficiencies or substandard conditions are subsequently addressed through a variety of programs:

- Preventative and Predictive Maintenance;
- Corrective Maintenance; and
- Reactive and Corrective Capital programs.[6]

[6] Exhibit 4, Tab 2, Schedules 1-4 for maintenance programs

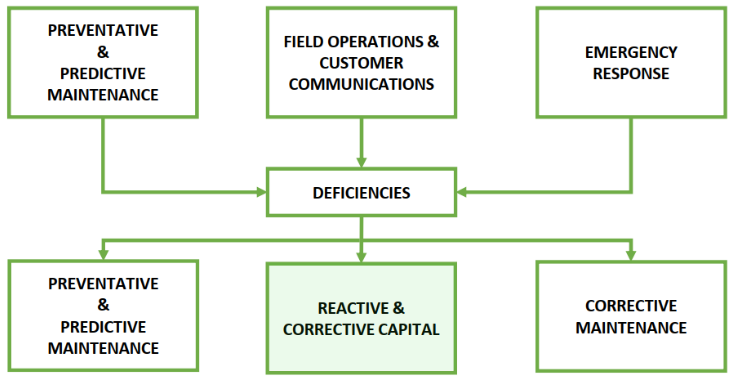


Figure 5: Deficiency Capturing Process[7]

- **Preventative & Predictive Maintenance Activities**: Field crews identify asset failures and deficiencies as part of scheduled maintenance and inspection activities. The inspection cycle depends on the maintenance program as per Reliability Centered Maintenance ("RCM"). The RCM framework is a comprehensive approach to the lifecycle maintenance of distribution system assets. RCM enables Toronto Hydro to leverage a methodological approach to preserve the asset's function by implementing failure management practices that target the potential functional failure.

- **Field Operations & Customer Communications**: Issues or actions identified can also be triggered by sources outside scheduled or planned maintenance activities. These include, but are not limited to:
  - Phone calls from customers to Toronto Hydro;
  - External emails to Toronto Hydro;
  - Observation by field crews during the normal course of operations;
  - Customer inquiries requiring field assessment and follow up; and
  - Line patrol for Worst Performing Feeder Program.

- **Emergency Response:** Reactive capital work can also be required as a result of emergencies or unplanned system events. These include asset failures and deficiencies identified outside of Toronto Hydro's daily (planned) operations but requiring follow-up remediation and reactive replacements in order to permanently restore power or eliminate safety or environmental risks.

[7] The deficiency capturing process is described in detail in Exhibit 2B Section D3.

Deficiencies from the above sources are reviewed to validate the need for reactive intervention, assessed to determine the nature of reactive intervention required (capital versus maintenance) and the level of urgency and priority (e.g. P1-P4) to be assigned to each asset deficiency. Toronto Hydro addresses the deficiencies identified by issuing work requests.[8]

For the Reactive Capital segment, Toronto Hydro uses a prioritization framework that classifies asset deficiencies into four categories:

- P1 requires resolution within 15 days;
- P2 requires resolution within 60 days; and
- P3 requires resolutions within 180 days;
- P4 which indicates that conditions are to be monitored.

Due to the unpredictable nature of asset failures, the number of reactive work requests may vary from year to year. Catastrophic failures of major assets can require large investments by the utility, and as such, Toronto Hydro requires the Reactive Capital segment to manage imminent major asset failures and address high-risk assets approaching imminent failure. This will help with providing reliable, safe, and environmentally responsible service to customers from 2025 to 2029 and beyond.

Figure 6 below shows the volume of reactive capital work requests issued from 2019 to 2022.[9]

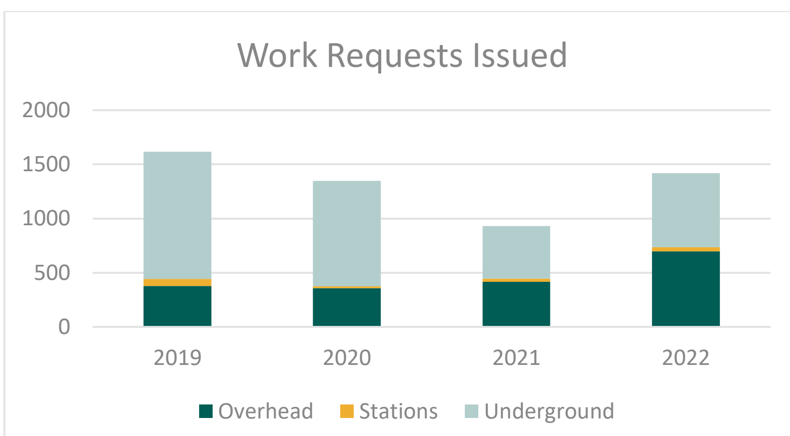


Figure 6: Historical Reactive Capital Work Requests Issued by System Type

[8] Work request are forms issued to assign / schedule corrective work addressed by Toronto Hydro or contractor crews. Deficiencies identified and work requests raised may have a one to one or many to one relationship (i.e. a single work request may contain more than one deficiency).

[9] 2018 data is excluded due to the transition to SAP that occurred during that year.

On average, 1,483 reactive capital work requests were issued each year between 2019-2022, with an overall downward trend, except in 2022, and representing a 9 percent decrease over the 2013-2017 average of 1,624 per year. Generally, the underground system contributes the most to both volume and cost to reactively replace assets, such as Underground Residential Design ("URD") vaults, transformer vaults, and network vaults. Note, that the level of spending depends not just on the volume, but the mix of the different types of work each year. For example, due to the size, operational complexity, and criticality of stations assets, station work can contribute significantly to the overall cost of the Reactive Capital segment, despite the relatively low volume of requests.

1. Metering Assets

The Reactive Capital segment also funds reactive meter replacement. Reactive meter replacement capital work consists of the replacement of defective metering equipment in the field including: smart meters, suite meters, interval meters, and primary meters (Including instrument transformers). The loss of communication with a meter is the primary cause of meter replacements. Primary metering units can also fail due to blown instrument transformer fuses which causes customer consumption to be incorrectly read, resulting in incorrect billing. Failed metering equipment not replaced in a timely manner can result in delayed billing and the need to estimate customer consumption.

Table 7 summarizes the estimated number of meter replacement units and costs for the 2025-2029 rate period. The estimated costs were derived based on a four-year weighted average of historical costs. The average percentage of meters failing remains the same but the population is increasing yearly. The meter replacement costs are embedded into the Reactive Capital segment 2025-2029 forecasts in the Expenditure Plan section.

Table 7: Reactive Meter Replacement Costs (2025 - 2029)

	Projected					
	2025	**2026**	**2027**	**2028**	**2029**	**Total**
Meter Replacements (Units)	5500	5600	5700	5800	5900	28500
Meter Replacement Costs ($ Millions)	3.56	3.66	3.76	3.89	4.02	18.88

E6.7.3.3 Worst Performing Feeders

Toronto Hydro's distribution system contains over 1,500 feeders that supply power to over 790,000 customers in the City of Toronto. While any one of these feeders is subject to random equipment breakdown, foreign interference and environmental effects that can cause unplanned outages, specific feeders experience a disproportionate number of problems and cause an unacceptably high number of sustained or momentary interruptions to the customers connected to them. Figure 7 below shows that between 15 and 20 percent of the total CI, and approximately 10 percent of CHI in a given year, are attributed to FESI-7 feeders, which make up less than 2 percent of all feeders, as shown in Table 8 below.

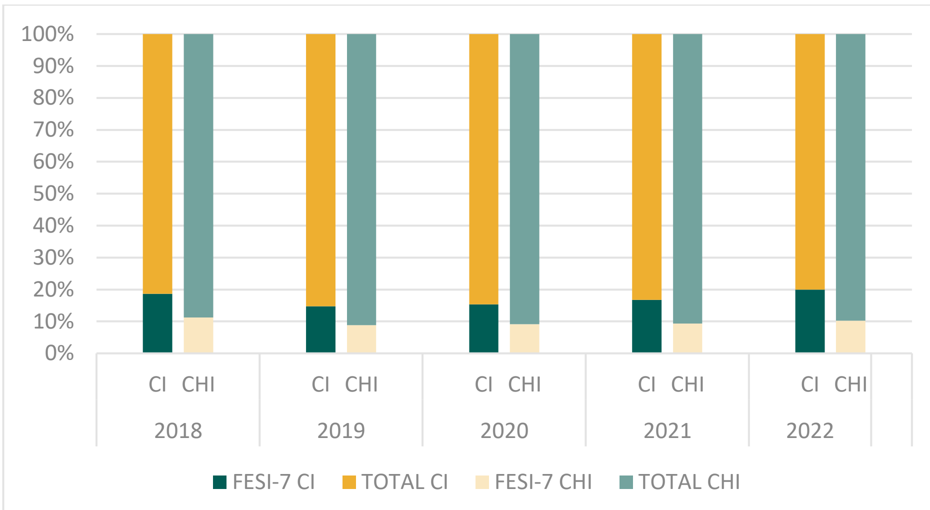


Figure 7: Contribution of FESI-7 feeders to CI and CHI between 2018 and 2022

Table 8: Number of FESI-7 feeders compared to total number of feeders

	2018	2019	2020	2021	2022
# FESI-7 feeders	17	7	9	10	27
Total # feeders	1521				
% FESI-7/total	1.12%	0.46%	0.59%	0.66%	1.78%

Figures 8 and 9 below show the locations of FESI-6 Large Customer feeders in 2020 and 2022 respectively. These feeders typically vary from year to year and are difficult to predict. Since planned renewal programs take a substantial amount of time to plan, design and execute, it is necessary to address emerging issues contributing to interruptions on these feeders in a timely manner.

Figure 8: Locations of 2020 FESI-6 Large Customer Feeders

Figure 9: Locations of 2022 FESI-6 Large Customer Feeders

The main objective of Toronto Hydro's WPF segment is to improve overall service reliability for customers supplied from poorly performing feeders, which aligns with results of the Phase 1 Customer Engagement, where reliability is one of the top three priorities across all types of customer types. This improvement is accomplished by employing a feeder-level analytical approach that selects feeders experiencing a high number of outages or trending towards increased outages, analyzing previous outages to determine the cause, and issuing work intended to address the cause in an effort to mitigate any subsequent outages. The WPF segment is designed to be a short-term mitigation measure and a complement to the planned renewal capital work. Feeders addressed by the WPF segment may still experience unpredictable failure and power outages, albeit at a lesser frequency until permanent, long-term solutions are implemented. Most of this work is targeted for completion within a 12-month period to mitigate the risk of customers being exposed to poor reliability for prolonged periods.

In addition to FESI-7 and FESI-6 Large Customer metrics, Toronto Hydro has begun to track a new metric, Customers Experiencing Multiple Sustained and Momentary Interruptions, or CEMSMI-10. This particular metric closely assesses the experience of each key account customer, as customers may be transferred to alternate supply feeders during contingency scenarios and may not consistently be supplied by their normal supply arrangement throughout the year. Additionally, since many key account customers are also negatively impacted by momentary interruptions (i.e. factory lines, hospital equipment), momentary interruptions are tracked along with sustained interruptions. Where a specific key account customer is trending towards a poor experience over a 12-month period, each feeder that supplies the specific customer will be targeted for analysis in an effort to address any deficiencies that may cause further interruptions.

Through this segment, Toronto Hydro first identifies feeders which are at risk of becoming designated FESI-7 or FESI-6 Large Customer feeders, feeders with KA customers experiencing a high volume of momentary interruptions or power quality issues (i.e. CEMSMI-10), or feeders with specific systemic issues that need to be addressed in the short term. This assessment excludes planned outages, outages occurring on Major Event Days ("MEDs"), outages caused by loss of supply, and interruptions on the secondary side of the distribution transformer. Toronto Hydro then assesses each of the past outages that occurred on the designated feeder, which includes but is not limited to:

- Reviewing comments from the Control Authority and crews attending to the outage;
- Checking for flags raised by SCADA-connected devices; and
- Reviewing voltage and current profiles collected by Ion meters in an effort to localize the outage, so that the cause may be identified and subsequently addressed.

Following a feeder reliability analysis, field crews patrol and inspect the feeders, with a particular emphasis on any locations identified during the analysis, to assess the condition of equipment and identify quick targeted actions that yield immediate reliability improvements. Examples of deficiencies discovered during such feeder patrols are shown in **Error! Reference source not found.**Figure 10 below.

Figure 10: Animal Contact on Metal Switch Bracket (Left)/Rusted Overhead Transformers at Risk of Leaking Oil (Right)

As previously stated and shown in Figure 1, 41 percent of all sustained interruptions are a result of the failure of defective equipment. Through the reliability analysis on poorly performing feeders, assets that are identified as having a risk of imminent failure are targeted for replacement before they would be scheduled for replacement under planned renewal programs. This addresses equipment deficiencies quickly before they cause subsequent outages on already poorly performing feeders.

Between 2020 and 2022, Toronto Hydro issued 107 WPF mitigation scopes to address asset deficiencies across an average of 31 different FESI-7 or FESI-6 Large Customer feeders per year. Figure 11 below shows the breakdown of asset types that were targeted for replacement. Toronto Hydro expects that this trend will continue through the 2025-2029 rate period and that there will be a similar breakdown of asset types requiring replacement through the WPF segment.

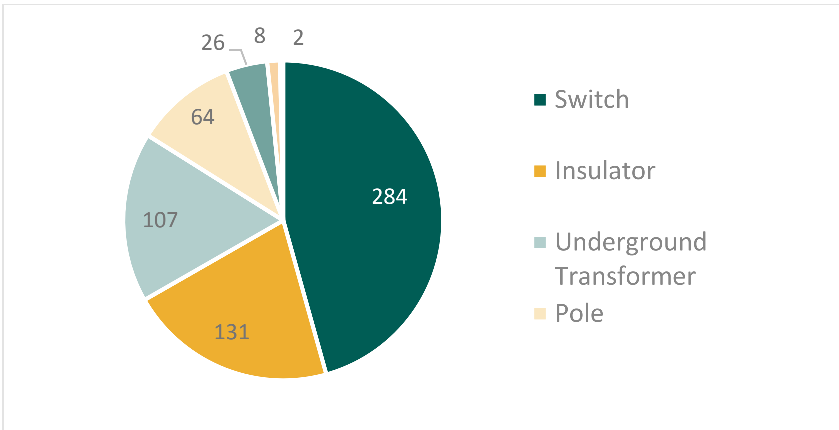


Figure 11: Breakdown of assets replaced under the WPF segment between 2020-2022

The top asset types scheduled for replacement through the WPF segment were overhead switches, insulators, and underground transformers. These assets were targeted for replacement in order to mitigate risk of failures due to the following issues:

Overhead switches with vintage porcelain insulators mounted onto metal brackets are susceptible to electrical tracking, whereby small amounts of current flow from the live switch terminals/end fittings, across the surface of the porcelain shell, to the grounded metal bracket. Electrical tracking is exacerbated by salt spray in the winter months and condensation when warm moisture-laden air comes into contact with a cold porcelain shell. Tracking can cause outages by triggering the operation of upstream protection, as well as degradation of the porcelain shell, leading to its fracture and a full asset failure. Figure 12 below shows a porcelain insulator with a hairline crack and scorch marks. New switches are fitted with larger polymer insulators and are less susceptible to electrical and mechanical failure mechanisms.

Figure 12: Porcelain insulator with small cracks in the shell and scorch marks

- Porcelain insulators mounted onto metal brackets have the same failure mode and mechanism as the above example. New insulators are manufactured using polymer.
- Single-phase submersible transformers manufactured with mild steel tanks and bare, uninsulated low voltage terminals are prone to premature failure where installed in locations susceptible to flooding. Transformers installed in these areas may experience accelerated corrosion of the tank, typically near the base, and potentially heavy corrosion of the aluminum secondary cables and steel tank near the low voltage terminals where the terminals are left bare and water levels inside the vault rise to the height of the terminals. Refer to the photos in Figure 13 below showing two transformers that had been removed from service due to extreme levels of corrosion. New single-phase submersible transformer tanks and lids are manufactured using stainless steel and are fitted with additional components that effectively seal live components from water ingress, mitigating the corrosion.

Figure 13: Mild steel single-phase submersible transformers with heavy corrosion

Figure 14 below shows the historical count of FESI-7 and FESI-6 Large Customer feeders per year. As shown, the annual number of FESI-7 and FESI-6 Large Customer feeders are a small subset of the more than 1,500 total feeders that make-up Toronto Hydro’s distribution system and are gradually trending down over time since the inception of the WPF segment. There was, however, a noticeable increase in the number of FESI-7 and FESI-6 Large Customer feeders in 2022 due to the increased sensitivity of the Outage Management System in recording interruptions, which is further explained in Exhibit 1B, Tab 02, Section 4 "Reliability Performance". It is also important to note, that the WPF segment is not the sole driver for the FESI-7 and FESI-6 Large Customer metrics, and that the success of these metrics is also heavily dependent on planned renewal programs, such as Underground System Renewal – Horseshoe.[10]

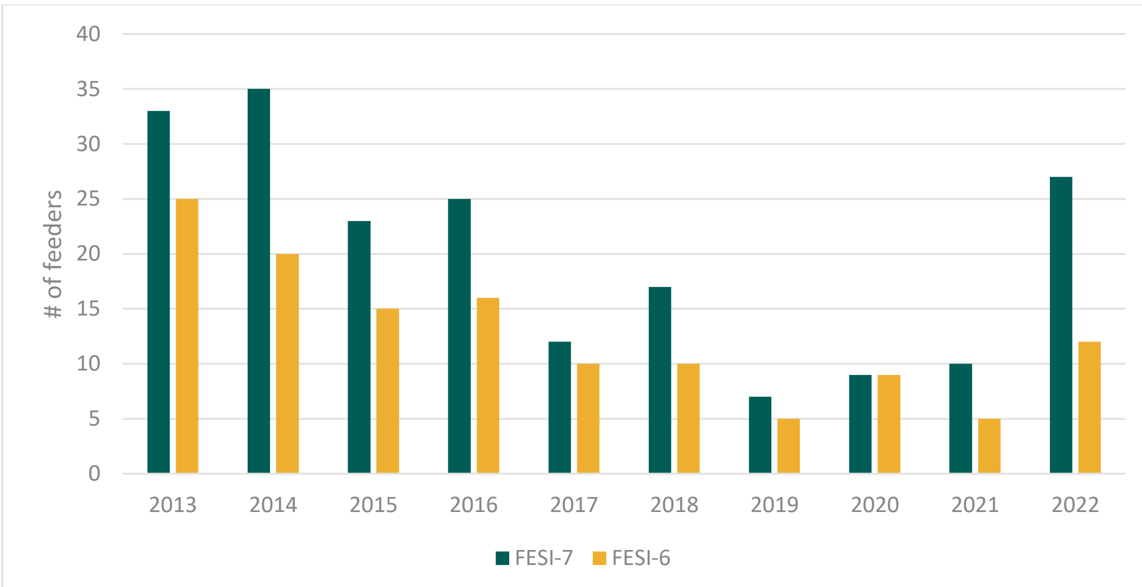


Figure 14: Historical Worst Performing Feeder Interruptions between 2013 and 2022

Although there has been an overall decline in the number of FESI-7 and FESI-6 Large Customer feeders, it is particularly important that the WPF program be maintained to sustain this decrease and continue to mitigate the risk of interruptions caused by equipment failures, as planned renewal programs have been prioritizing the replacement of transformers containing PCBs, which has reduced investment in more reliability-focused work (e.g. replacing high-risk direct-buried cable).

The WPF segment is designed to be a short-term mitigation measure and a complement to the planned renewal capital work. Feeders addressed by the WPF segment still experience unpredictable failure and power outages, albeit at a lesser frequency until permanent, long-term solutions are implemented. Overall, the WPF segment has been successful in reducing the frequency of power

[10] Exhibit 2B, Section E6.2.

interruptions for customers on feeders that are experiencing especially poor reliability performance, as shown in Figure 14 above.

E6.7.4 Expenditure Plan

Table 9 provides the Actual (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for the Reactive and Corrective Capital program.

Table 9: Historical and Forecast Program Costs ($ Millions)

	Actual			Budget		Plan				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Reactive Capital	58.7	50.9	56.0	55.1	53.1	55.4	58.4	58.3	60.6	62.8
Worst Performing Feeder	4.2	3.7	3.8	6.7	5.7	6.1	6.3	6.5	6.7	6.9
Total	**62.9**	**54.5**	**59.7**	**61.7**	**58.7**	**61.6**	**64.8**	**64.8**	**67.3**	**69.7**

E6.7.4.1 Reactive Capital Segment

Toronto Hydro invested $165.6 million in reactive capital work over 2020-2022 and projects to invest a total of $273.7 million by the end of 2024 (including forecasted inflation), which is approximately $17 million more than the $256.8 million budget approved by the OEB in the 2020-2024 rate application. Due to the demand-driven, non-discretionary nature of this segment and the volume and mix of work that needed to be addressed, Toronto Hydro could not reasonably constrain spending for this spending to the OEB approved amount.

Actual work volumes and costs will vary from year to year and Toronto Hydro forecasts future costs based on historical trends. Toronto Hydro developed its forecasts for 2020-2024 in 2018 based on the best available information at the time, which reflected an increasing trend that has since plateaued. That being said, Toronto Hydro has since developed a more detailed projection model for its 2025-2029 forecast, which is discussed below.

The predominant driver for the variance during the 2020-2024 rate period is the demand-driven nature of the actual volumes and type of assets requiring non-discretionary replacement. The unpredictable nature of asset failures can vary in type and number of equipment from year to year due to foreign interference or weather. For example:

- The volume of condemned pole reactive replacements can increase as the overall condition of poles deteriorates, as indicated by the number HI4/HI5 poles. Toronto Hydro replaces condemned poles, identified through inspections, both reactively and through proactive (planned) renewal. The total number of condemned poles approximately doubled from 2020 to 2021 and remained at a similar level in 2022. Toronto Hydro has seen a steady increase in reactive pole replacement, which includes not only condemned poles but any pole replacements required due to emergency or storm events. Given the current and projected condition of Toronto Hydro's wood poles, the utility expects this trend to continue.
- The total volume of overhead and underground transformer replacements declined from 2020 to 2022. In 2020, there were 849 transformer related work requests which decreased by approximately 50 percent in 2022. This reduction is likely due to the Toronto Hydro's recent focus on eliminating transformers at risk of containing PCBs, which are also at higher risk of failure due to their age. Toronto Hydro expects the number of transformer replacements to plateau over the next 3 to 4 years.

Toronto Hydro's 2025-2029 Reactive Capital predictive model uses a layered approach, which is based on the previously established weighted moving average methodology, but also incorporates relevant condition-based information for underground distribution transformers to forecast future capital expenditure. The underground transformer forecast leverages historical reactive replacement data to determine the average probability of reactive replacement for a given health index band. The model considers a 3-year window of anticipated asset deterioration as per ACA projections, which corresponds to the longest underground transformer inspection cycle. Expenditures beyond the 3-year window are calculated using the conventional weighted average methodology. Toronto Hydro's corresponding forecast of work request volumes is shown in Figure 15, along with historical actuals.

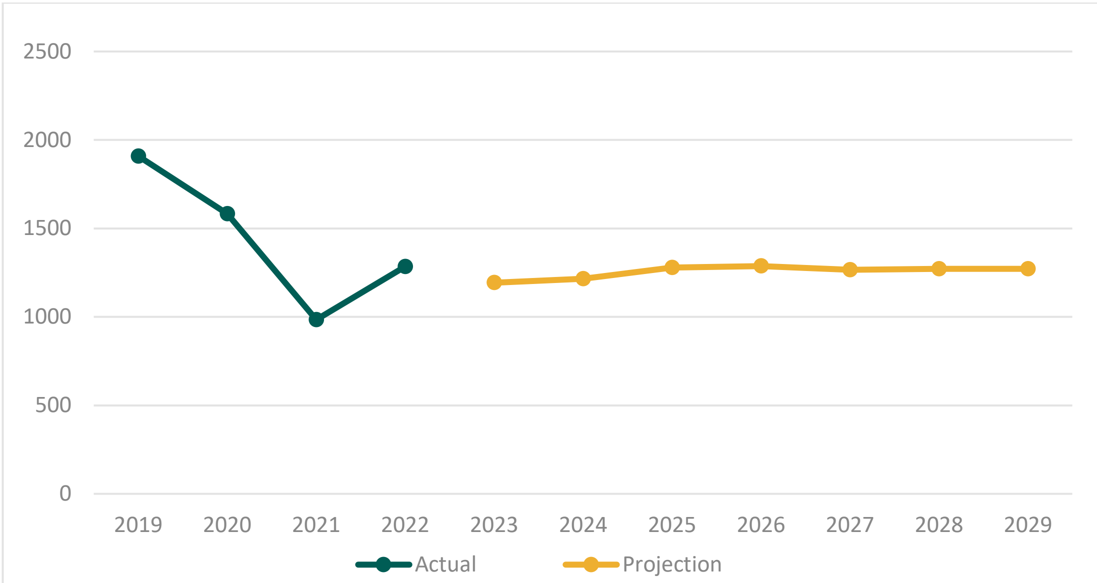


Figure 15: 2019-2029 Reactive Capital Work Requests Actuals and Forecast

As previously noted, the nature of work in this segment is unplanned, unpredictable, non-discretionary, and can vary significantly from year to year. When an asset exhibiting severe deficiencies is found through maintenance inspections, reported by operations teams or customers, or caused by emergency events, the utility immediately assigns personnel to triage and resolve the issue. Based on the expertise and experience of Toronto Hydro engineers and operation teams, deficiencies are evaluated and prioritized for resolution. Crews are then dispatched to address those assets with the highest priority based on severity of the issue and the impact on environmental, safety and reliability.

Since 2015 Toronto Hydro has also undertaken efforts to maximize the productivity, safety, reliability, and environmental benefits of reduced switching work on the downtown "grid" system. Where possible for P3 work types, planned maintenance, customer or capital work can be bundled together to align with feeders that are taken out of service to create a safe work zone for repairs or equipment replacement which can reduce the switching costs. Due to lower urgency and more flexible turnaround times, P3 work can be aligned with upcoming maintenance, capital, or customer work.

Toronto Hydro has also taken steps to improve work processes in this segment, including: better coordination within the utility to ensure material availability; enhanced inspection forms; and adoption of software tools to improve tracking, management, and reporting of work requests and reduce manual work.

E6.7.4.2 Worst Performing Feeder Segment

Between 2020 to 2022, Toronto Hydro invested $11.7 million in the WPF segment, and projects to invest an additional $12.4 million, for a total of $24.1 million by the end of 2024. The total spend is projected to be slightly less than the $24.9 million forecast in the 2020-2024 DSP, while still generally expecting to meet segment objectives (i.e. meeting or exceeding FESI targets). The WPF segment has proven to be a cost-effective means of managing reliability issues in the short term.

In order to address the evolving needs of customers, for whom reliable service has gained importance, Toronto Hydro needs to invest in this segment at slightly higher rate, for a total of $32.5 million over the 2025-2029 rate period. Some of the main drivers for this are summarized below.

Due to the increased sensitivity of the Outage Management System noted previously, a higher proportion of outage events that occur on the system will be logged, providing Toronto Hydro better visibility into poor performing feeders and actual customer reliability experience. This will enable Toronto Hydro to better mitigate issues and improve service for customers experiencing poor reliability. However, this also requires more investment and will put upward pressure on measures such as FESI-7. Similarly, the new CEMSMI-10 measure provides better visibility into large, sensitive customers experiencing poor reliability (including momentary interruptions), which Toronto Hydro will need to invest in addressing. Finally, due to the recent focus on removing PCBs from the system through programs such as Overhead System Renewal and Underground System Renewal – Horseshoe, Toronto Hydro has been investing less in reliability-focussed proactive renewal of the distribution system, increasing the need for short-term mitigation measures taken through WPF segment.

Toronto Hydro has based its 2025-2029 forecast expenditures for the WPF segment on historical trends and considering the factors noted above. The utility prioritizes WPF scopes based on the reliability performance of each feeder and field patrol findings. The intent of the short-term capital work is to mitigate immediate risk to reliability by replacing or upgrading assets that are at high risk of failure that will result in power outages. Most of this work is targeted for completion within a 12-month period so the outcome of reliability improvement is realized immediately thereafter.

E6.7.5 Options Analysis

E6.7.5.1 Reactive Capital Segment

Toronto Hydro considered three different forecasts for funding the replacement of failed or failing assets for the 2025-2029 rate period:

1) **Lower Bound** – Annual need and costs remain consistently on lower end of historical experience;
2) **Most Likely** – Toronto Hydro's best estimate of needs and costs for this segment based on historical trends and asset condition; or
3) **Upper Bound** – Annual needs and costs reflect higher end of historical experience.

1. Option 1: Lower Bound

As for all three options, this forecast relies on Toronto Hydro's Reactive Capital predictive model to estimate future costs. However, under this option the forecast expenditures in each year are adjusted downward to reflect the assumption that the volume and costs of required work will be consistently on the low end of Toronto Hydro's recent experience with no major storm events or other factors to drive up costs. While it is possible that the required work in one year could drop to this level, it is not very likely and it would be very unrealistic to expect it to stay around that level for a full five-year period.

Implementing this option would very likely result in inadequate funding to meet the demand for reactive capital work based on historical trends. A backlog of work would arise and deprive planned capital or maintenance programs of required resources. Addressing reactive capital work through planned capital rebuilds would also take time to plan, design and execute and would not typically allow for the timely replacement of failed and failing assets. Inadequate funding would also increase environmental risk, and safety risks to the public and Toronto Hydro employees. Ultimately this would lead to more interruptions and longer outages for customers, potentially significant legal consequences (e.g. related to environmental obligations), and risk of worker and public safety incidents.

2. Option 2 (Selected Option): Most Likely

The expenditures for this option are forecast using Toronto Hydro's Reactive Capital predictive model and represent the utility's best estimate of required spending in this segment over the 2025-2029 rate period. The proposed investment levels are necessary to maintain system performance and reliability, ensure customer satisfaction, eliminate safety risks to the public and Toronto Hydro employees, and mitigate environmental risks.

3. Option 3: Upper Bound

This option is the reverse of Option 1, i.e. the forecast expenditures from the predictive model are adjusted upwards to reflect a scenario where the required work is at the higher end of Toronto Hydro's recent experience. Under this option, Toronto Hydro would also ensure no backlogs of work, while also being in a better position to address any storm events without compromising funding needed for its other capital work. While this would be ideal from a risk management perspective, the extra costs are not prudent given the relatively low likelihood of there being that level of need over the full five-year period.

E6.7.5.2 Worst Performing Feeder Segment

Toronto Hydro considered three alternatives for addressing the WPF segment's budget for the 2025-2029 rate period:

1. Managed deterioration - Reduction of work issued under the WPF segment, addressing asset replacement mainly through planned renewals;
2. Sustainment - Continuation of the current WPF segment, addressing asset replacement at similar levels as seen in the 2020-2024 rate period;
3. Improvement - Enhancement of the WPF segment, addressing asset replacement at higher levels than previously seen in the 2020-2024 rate period (preferred option)

1. Option 1: Managed Deterioration

Under this option, Toronto Hydro would reduce the pace of WPF work. Addressing deficiencies on feeders exhibiting poor reliability mainly through planned capital renewal programs is an adequate solution for the long term, however, planned renewal projects take significantly longer to plan, design and execute; and do not typically allow for the timely mitigation of worsening reliability trends on poorly performing feeders. Additionally, the planned capital renewal programs have recently been focused on the replacement of PCB transformers. Without sufficient targeted, short-term interventions on poorly performing feeders, many customers would likely experience worsening reliability. It is expected that the number of FESI-7 and FESI-6 Large Customer feeders, and CEMSMI-10 customers would increase, negatively impacting customers for prolonged periods. This option does not align with the Phase 1 Customer Engagement report conducted in 2022, which identified a growing preference for reliable service, and therefore this option is not recommended.

2. Option 2: Sustainment

Under the sustainment option, Toronto Hydro would continue issuing mitigation work at the current pace, which has proven effective over recent years. However, given the pressures on reliability metrics discussed previously (e.g. recent focus of planned renewal programs on removing PCBs transformers), Toronto Hydro expects that this level of investment will not be sufficient to prevent the number of FESI-7 and FESI-6 Large Customer feeders, and CEMSMI-10 customers from increasing. More importantly, some customers will face delays in having their poor reliability addressed and customers have made it clear that reliability is a top priority. Therefore, this option is not recommended.

3. Option 3: Improvement

Under the Improvement option, Toronto Hydro will increase the pace of spending by a small amount in this segment to address pressures on reliability and customer priorities. This option will provide immediate reliability improvements to more customers served by poor performing feeders at a reasonable cost, and serves as a "bridge" solution until planned capital rebuilds can be executed. This option is a reasonable balance of the top customer priorities of price and reliability by spending a little bit more to improve service reliability for those experiencing worse than average performance in the short term, until planned renewal projects can take place.

E6.7.6 Execution Risks & Mitigation

Each segment of the Reactive and Corrective Capital program faces challenges which can delay or prevent work from occurring. Many of these challenges overlap across the two segments of this Program. These challenges are summarized in the table below.

Table 10: Execution Risk Applicability by Segment

Segment	Execution Risks			
	Material Constraints	Resource Constraints	Logistics Constraints	Planned Work Restrictions
Reactive Capital	✓	✓	✓	✗
Worst Performing Feeder	✓	✓	✗	✓

E6.7.6.1 Material Constraints

Both segments use major equipment, which includes but is not limited to, transformers, switches, switchgear, and poles. The procurement lead time for a major asset can vary from 21 days to 14 months based on the type. For this reason, it is difficult and sometimes infeasible to advance or expedite the requests. Supplier shortages affecting material availability may cause delays in executing the work in a timely manner. For more details and what Toronto Hydro has been doing to address this issue please see Exhibit 4, Tab 2, Schedule 13 (Supply Chain). To help mitigate this risk, Toronto Hydro orders assets in advance of expected in-service dates and ensures sufficient supply of critical spares.

E6.7.6.2 Resource Constraints

Both segments use design and construction resources. Therefore, if there are insufficient resources to complete all the projects in the Program, certain requests will need to be deferred to ensure highest priority requests are completed. Unpredictable events such as major snow storms or a resurgence of the COVID-19 pandemic could also contribute to lack of construction resources. Furthermore, depending on the location or type of failure, further design, planning, and approval may be required prior to work execution. For example, work may require pole loading, cable pulling or voltage drop calculations by a designer prior to replacing the asset in the field. Toronto Hydro is mitigating this risk with the help of third party (e.g. contractors) to complete any project in excess of Toronto Hydro's resources capacity.

Under the WPF segment, in order to assist with the mitigation of this risk, Toronto Hydro has mapped out the WPF process, where feeder patrols scheduling and timelines for project execution have been clearly established. As a result, mitigation work is normally placed on high priority and scheduled for field execution taking into consideration available resources. Additional emphasis is placed on feeders that have experienced a high number of outages in a 12-month rolling window.

E6.7.6.3 Logistics Constraints

Reactive Capital work can face challenges such as installation of legacy equipment, lack of space in a vault or feeder not being able to be taken out of service. For these reasons, there is a risk of delay as additional teams may need to be involved for further analysis. Toronto Hydro is mitigating this risk by ensuring clear communication with the overhead or underground renewal portfolios.

E6.7.6.4 Planned Work Restrictions

Under the WPF segment, since this is planned work and is not generally considered to be as urgent as reactive replacements of failed equipment, feeder scheduling restrictions and road work moratoriums may also pose risks to the completion of work in a timely manner. To mitigate this risk, monthly stakeholder meetings are scheduled to review status of work, emerging issues, as well as alternatives to ensure work is completed in a satisfactory manner and time frame.

E7.1 System Enhancements

E7.1.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 26.3	**2025-2029 Cost ($M):** 151.2
Segments: Contingency Enhancement, Downtown Contingency, System Observability	
Trigger Driver: Reliability	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Financial Performance	

The System Enhancements program (the "Program") is comprised of three strategic investment initiatives that are designed to modify and augment the distribution system, with the goal of ensuring that, by 2030, the physical grid is equipped with the foundational technologies and capabilities necessary to optimize the efficiency of grid operations and deliver incremental customer value in response to emerging risks and drivers. These drivers include (1) the accelerating electrification of energy demand (e.g. electric vehicles and cold-climate heat pumps); (2) accelerating adoption of distributed energy resources (e.g. rooftop solar and batteries); and (3) increasing risks to reliability and resiliency from the effects of climate change (i.e. adverse weather events).

The System Enhancements program consists of the following three segments:

- **Contingency Enhancement:** This segment enhances Toronto Hydro's ability to optimize the grid and efficiently restore power to customers by: (1) adding remotely operable feeder tie and sectionalizing points on feeders where the number of switching points is currently sub-optimal or where there is an opportunity to facilitate or expand a distribution automation network, (2) upgrading undersized conductors on lateral loops to improve contingency options, and (3) upgrading undersized trunk egress cables. Toronto Hydro plans to invest an estimated $132.9 million in 2025-2029 in Contingency Enhancement, which is a significant increase in segment spending relative to the forecast total for the 2020-2024 period. The increased pace of investment reflects Toronto Hydro's strategic objectives for grid modernization. By 2030, the utility aims to deploy sufficient remote operable switching points to allow for distribution automation across the Horseshoe region, where reliability has typically been more challenging to maintain (compared to the Downtown system) and where significant growth causing system strain is forecasted, particularly in the Horseshoe west region of the distribution system. This segment also introduces modern switching assets that will provide automated and remote controllability functions to address feeders experiencing numerous momentary and sustained interruptions. Such devices include but are not limited to reclosers on the trunk and laterals of feeders. Reclosers are pole-mounted breakers which will allow Toronto Hydro to better prevent momentary interruptions from cascading into prolonged outages, and to better isolate a feeder during sustained interruptions, thereby limiting the number of customers impacted by an outage. A fault event on the feeder downstream of the recloser will only cut off power to that section instead of the entire feeder by coordinating with the station breaker, which would primarily benefit those customers that are particularly sensitive to momentary interruptions. Furthermore, installing a recloser on the lateral section of a feeder will provide advanced lateral protection, which prevents temporary faults from becoming sustained outages and avoids momentary interruptions on feeders. The devices proposed under this segment support Toronto Hydro's *Grid Modernization Roadmap*.

- **Downtown Contingency:** This segment provides for plans to add provisions in the downtown core for incremental Toronto Hydro-controlled back-up supply to stations – above and beyond existing Hydro One provisions. Toronto Hydro plans to invest an estimated $13.6 million during the 2025-2029 period in the Downtown Contingency segment. Major loss-of-supply incidents – driven by a variety of causes – have become more frequent in recent years, underscoring for the utility and many of its critical downtown customers (e.g., financial institutions; shopping centres; office towers; large multi-residential buildings; hospitals; etc.) the importance of grid resiliency. The planned enhancements will provide N-2 (i.e., two station loss-of-supply issues at the same time) operational capability to address serious loss-of-supply scenarios. These investments will bring the downtown and horseshoe back-up supply practices into greater alignment with one another, improving resiliency in areas of the system with highly critical loads. The impact of significant outage events in the Downtown core will be of increasing concern to customers and stakeholders as the economy becomes more reliant on electricity in the next decade and beyond.

- **System Observability:** This segment introduces new assets that can provide real-time condition data, loading data and fault-finding capabilities. Such devices include, but are not limited to, overhead and underground sensors, online cable monitors, and transformer monitors as well as considerations for emerging technologies. By installing monitoring on

Toronto Hydro's overhead and underground assets, power outage response times would be improved by the devices' ability to provide alerts and fault localization in real time. The installation of online cable monitors provides real-time thermal profiles of cables, determines actual loading to enhance decision making on loading/connections and provides a better understanding of cable risk. These devices are also beneficial for monitoring cables in locations that require long or costly preparations for inspections. Toronto Hydro plans to invest an estimated $4.7 million in 2025-2029 in System Observability. Overall, these assets are intended to provide real-time or near-real-time information and will expand on pilot programs and focus on system reliability improvements for planned and unplanned scenarios.

The investments in this program represent a substantial portion of the Intelligent Grid component of Toronto Hydro's *Grid Modernization Roadmap*. For more details on the Intelligent Grid strategy, please refer to Exhibit 2B, Section D5.

Overall, Toronto Hydro plans to spend an estimated $151.2 million in this Program over the 2025-2029 period.

E7.1.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Reducing fault isolation times and the average duration of outages by installing SCADA switches and SCADA-enabled tie and sectionalizing points ○ Reducing the average duration of outages on targeted feeders by installing SCADA-enabled tie and sectionalizing points as well as reclosers; ○ Reducing outages resulting from contingencies by upgrading undersized or de-rated equipment; ○ Using real-time monitoring to detect line disturbance, proactive monitoring of cables, and providing information to identify early signs of failure and to proactively manage the load on the system. • Reduces the impact of downtown Major Event Days (MED) by:

	○ Providing back-up supply for low probability, high impact, long duration station loss-of-supply incidents; ○ Reducing the average duration of outages due to loss-of-supply incidents.
Operational Effectiveness - Safety	• Continues to maintain Toronto Hydro's Total Recorded Injury Frequency (TRIF) measure and safety objectives by installing remote switching, thereby reducing crew exposure to safety risks associated with manual switching
Financial Performance	• Contributes to Toronto Hydro's financial objectives by: ○ Leveraging distribution system automation (including real time loading, and remote switching operations) to reduce operational costs associated with patrolling faulted sections of the feeders; ○ Improving power outage response time through real-time power interruption alerts, remote switching operations, and better optimizing resource management (i.e. crews patrolling feeders to identify fault location).

E7.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Reliability
Secondary Driver(s)	Safety, Operational Constraints, System Efficiency

Toronto Hydro has developed a Grid Modernization Roadmap which aims to (1) leverage technology to improve the efficiency of the grid, and (2) develop capabilities that are responsive to emerging risks and drivers. These drivers include the accelerating electrification of energy demand (e.g. electric vehicles and cold-climate heat pumps); accelerating adoption of distributed energy resources (e.g. rooftop solar and batteries); and increasing risks to reliability and resiliency from the effects of climate change (i.e. adverse weather events).[1]

The System Enhancements program (the "Program") is the most important part of the Intelligent Grid component of the utility's Grid Modernization Roadmap for 2025-2029. It is comprised of three strategic investment initiatives which will modify and augment the distribution system, with the goal

[1] Exhibit 2B, Section D5

of ensuring that, by 2030, the physical grid is equipped with the foundational technologies and capabilities necessary to achieve sufficient flexibility, automation and resiliency in grid operations.

Investments in the System Enhancements program are necessary to support the utility's system reliability objectives for 2025-2029. Across the system, Toronto Hydro has identified opportunities to maintain and improve reliability and resiliency by implementing targeted system modifications. These system design interventions can cost-effectively mitigate the consequences of failure in many circumstances (i.e. the number of customers affected and outage duration), as distinguished from investments that reduce the probability of failure, such as replacing or maintaining aging and poor condition assets or trimming trees. The investments in this Program will reduce the consequence of failure by improving power restoration capabilities during both normal interruption events and adverse weather events, which are becoming increasingly frequent, as outlined in the Climate and Weather component of the Overview of Distribution Assets for 2025-2029.[2] Other investments in this program will establish capabilities to monitor distribution asset performance and loading in real-time, allowing for early detection of conditions that could warrant proactive interventions to avoid or reduce the impact of failures and violations of system operating parameters.

The following sections discuss each of the three program segments in greater detail.

E7.1.3.1 Contingency Enhancement

This segment includes the following four types of work, three of which are continuations of activities included in Toronto Hydro's 2020-2024 Distribution System Plan:

1. Installing additional SCADA-enabled tie and sectionalizing points in the Horseshoe area in an effort to reduce outage restoration times, improve system resiliency and support Distribution Automation;
2. Installing additional SCADA-enabled tie and sectionalizing points in the open loop overhead areas of the Downtown distribution system in an effort to reduce outage restoration times and improve system resiliency;
3. Upgrading undersized loop conductors in the Horseshoe area; and
4. Upgrading the capacity of trunk egress cables in the Horseshoe area.

Each of these activities is discussed in the following sections.

[2] Exhibit 2B, Section D2.1.2

1. Installing SCADA-enabled Tie and Sectionalizing Points in the Horseshoe area

When a feeder or section of feeder loses power during a contingency event, customers connected to it should receive power from an alternate feeder via feeder tie points and sectionalizing switches. However, if a feeder is not sufficiently equipped with sectionalizing or tie points that can divide the load into smaller sections, re-routing service may not be possible for all customers. This is especially true during peak loading times. Load growth and the addition of new developments can exacerbate this problem as less capacity is available on the feeders. The Contingency Enhancement segment adds tie or sectionalizing points to those feeders lacking sufficient switches.

A secondary issue is the lack of remote operation at some existing tie-points. Before SCADA-controlled devices were available, manual switches were installed. To restore power with manual switches, crews must travel to perform the switching work on-site. Depending on the location of the fault and accessibility of the switches, this typically takes one to two hours. In contrast, SCADA-controlled switches will relay instant loading information to the control room, enabling controllers to remotely re-route power to adjacent feeders within minutes. Remotely controlled switches are also safer than manual switches because employees are not exposed to live equipment during manual switching operations.

Toronto Hydro plans to deploy reclosers alongside traditional SCADA switches to eliminate interruptions to sections of customers on a feeder, thereby reducing overall outage times and improving system resiliency. Reclosers provide additional protection to overhead electrical distribution systems by acting as circuit breakers with electronic reclosing capability. By installing a recloser on the trunk of a circuit feeder, it effectively and efficiently contains any temporary or forced outages within that specific section, without affecting upstream customers. Toronto Hydro has successfully piloted reclosers within the distribution system and is ready to roll-out at scale in situations where they will provide necessary incremental benefits to static switches.

Toronto Hydro plans to strategically deploy both reclosers and traditional SCADA switches to enable faster power restoration in the Horseshoe area:

1. Installation of SCADA-enabled tie and sectionalizing points to provide appropriate backup supply; and
2. Installation of reclosers to constrain the impact of an outage to a section of a feeder.

The addition of SCADA controlled tie and sectionalizing switches enables Toronto Hydro to segment a feeder into smaller sections, transferring load to alternate feeders and minimizing the duration of power outages. To provide an appropriate back-up supply, Toronto Hydro divides feeders into sections using SCADA-operated switches, where one section serves approximately 700 customers. Each sectionalized portion of the feeder should contain a SCADA tie point that is connected to another feeder. In most instances, to meet this requirement, feeders will require at least three strategically located tie points connected to three unique back up feeders where:

1. The first tie point connects to another feeder from the same substation bus;
2. The second tie point connects to another feeder on a separate bus located at the same substation; and
3. The third tie point connects to another feeder from a different substation.

This configuration ensures a contingency power source is available for the faulted feeder regardless of whether the fault occurs at the feeder, bus, or station level, effectively reducing the duration of an outage. During the 2018-2022 period, the average duration for outages on feeders with less than three SCADA tie-points was approximately 707 minutes per year per feeder, whereas the average duration of those feeders with three or more SCACA tie-points was approximately 496 minutes.

Figure 1 below shows a map of Toronto highlighting the location of all the Horseshoe feeders that have less than three SCADA tie points.

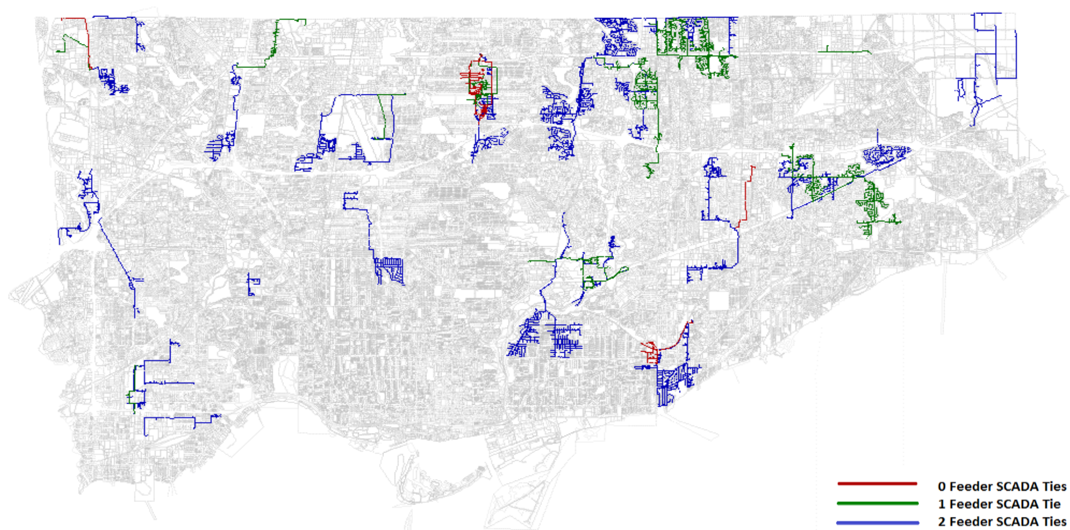


Figure 1: Map of Toronto showing Horseshoe Feeders with less than 3 SCADA Tie Points

Reliability data such as total customer minutes out ("CMO") over the five-year period from 2018-2022 and potential reliability improvement will be the main criteria in determining where the SCADA switch installation work will be carried out. The potential reliability improvement is determined by evaluating the existing SCADA switch condition on a feeder, and what potential improvement could be achieved if the feeder is modified to have a SCADA sectionalizing switch and a SCADA tie switch for every 700 customers connected to the feeder. Figure 2 below illustrates a 25 percent potential reliability improvement when a feeder that has approximately 2,800 customers has been upgraded from its existing condition. The upgrade includes two new SCADA sectionalizing switches to meet Toronto Hydro's Standard Design Practices ("SDP") where approximately 700 customers are to be connected in each section of the feeder. The ability to restore more customers increases following a sustained outage, as more focused isolation of the fault can be achieved.

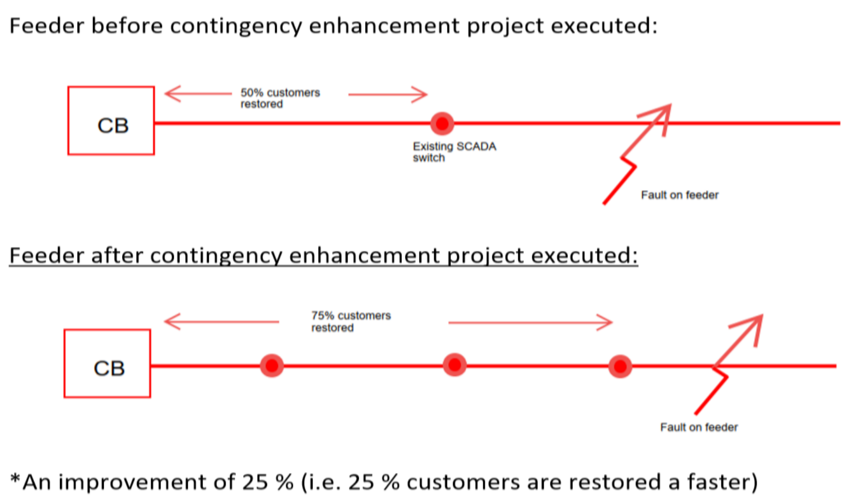


Figure 2: Potential Reliability Improvements Through Contingency Enhancement Investments

During the 2025-2029 period, Toronto Hydro plans to install a total of 205 SCADA switches on 94 feeders in the Horseshoe area. This work is expected to result in an average of approximately 12.6 percent reliability improvement on the 94 feeders where SCADA switch installation work is expected to take place. This will result in an average yearly total CMO reduction from 180,113 during the 2018-2022 period to an improved average yearly total CMO of 162,889. The potential SAIDI improvement as a result of this work is expected to be approximately 0.022 minutes per feeder per year.

Toronto Hydro intends to install reclosers alongside the installation of other SCADA-switches to enhance the grid's response to outages by containing their impact to a specific section of a feeder.

The recloser introduces new functionality where it will also operate automatically in response to a fault in a coordinated manner such that downstream customers on the faulted section of the feeder will be isolated without interrupting the remainder of the feeder. Figure 3 demonstrates that if a sustained or momentary fault were to occur downstream of a recloser, all customers upstream of that recloser will not experience an outage.

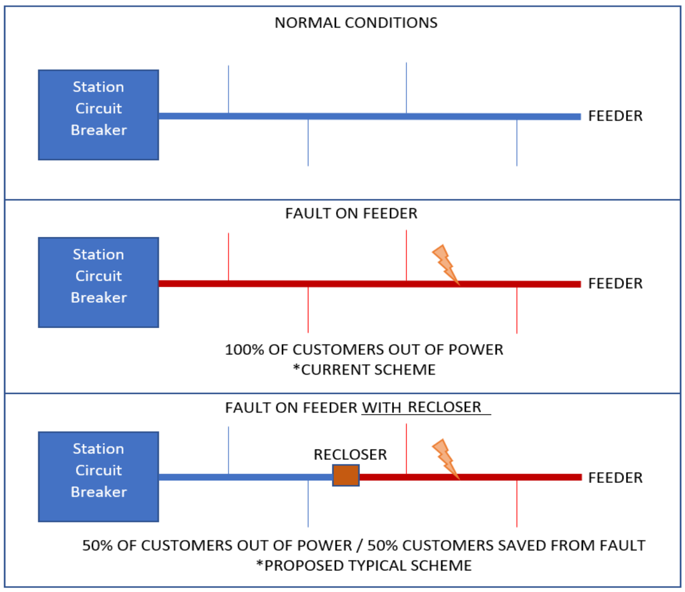


Figure 3: Concept Behaviour of Reclosers in the Distribution System for Sustained and Momentary Faults

The installation of a recloser near the halfway loading point on the circuit feeder trunk will result in significant improvements to MAIFI, SAIFI, SAIDI, and CAIDI. In particular, placing reclosers on the feeder downstream of customers sensitive to power outages can improve power quality as reclosers efficiently respond to downstream faults without impacting upstream customers.

Where coordination is possible, the utility can install multiple reclosers. This will improve reliability by decreasing the number of customers affected by an outage from 50 percent to 33 percent by strategically placing reclosers at the one-third and two-thirds loading points on the feeder trunk.

At a minimum, Toronto Hydro plans to install one recloser per overhead feeder prioritizing those with high historical CMO and CI, high number of customers, and/or on heavily loaded feeders. Based on the results of the recloser pilots, the potential SAIDI improvement is expected to be up to 0.108

minutes per feeder per year. Reclosers also reduce the number of customers experiencing an outage, with a potential SAIFI improvement expected to be up to 0.001 customers per feeder per year.

Additionally, reclosers have intelligent switching capabilities, allowing them to test for faults and voltage sensing on the upstream and downstream portion of the feeder. This enhanced visibility improves outage management and provides incremental information that can be analysed and used for decision-making. These additional features minimize transformer substations faults, extending their useful life; and reduce thermal and mechanical stress on cables, conductors, and connection points will experience less thermal and mechanical stress caused by faults.

Furthermore, the SCADA switch installation work in the Horseshoe will also support Distribution Automation. With the foundational SCADA devices installed, Distribution Automation will be deployed to rapidly isolate a fault and minimize the number of customers affected, without any manual intervention. Distribution Automation requires two main components: SCADA switches, and a Fault Location, Isolation and Service Restoration (FLISR) application. They are as follows:

1. SCADA switches on feeders allow the remote troubleshooting and sectionalizing of feeder faults to achieve more efficient and rapid troubleshooting and restoration, which is the focus of the Distribution Automation work within the Contingency Enhancement segment.

2. FLISR is an application which, together with the Network Management System (“NMS”), can automatically read and process signals from the distribution system to locate a fault. The implementation of Distribution Automation using FLISR would enable Toronto Hydro to rely on autonomous detection and isolation of affected portions

During a feeder level outage, control room operators and crews first work to locate the fault and sectionalize the feeder to isolate the faulted section. This will minimize the impact of the outage to a large portion of the customers before crews are able to identify the root cause of the outage and complete repairs. The use of remote operated SCADA switches reduces the fault isolation time by approximately one hour on average. If a feeder has a recloser and a fault occurs downstream, it can save an upstream customer from experiencing any interruption. The use of FLISR would further improve fault isolation and service restoration by remote operating additional SCADA switches to further sectionalize faulted sections of the feeder and restore healthy portions of the feeder. Figure 4 illustrates the benefits of a feeder with FLISR enabled.

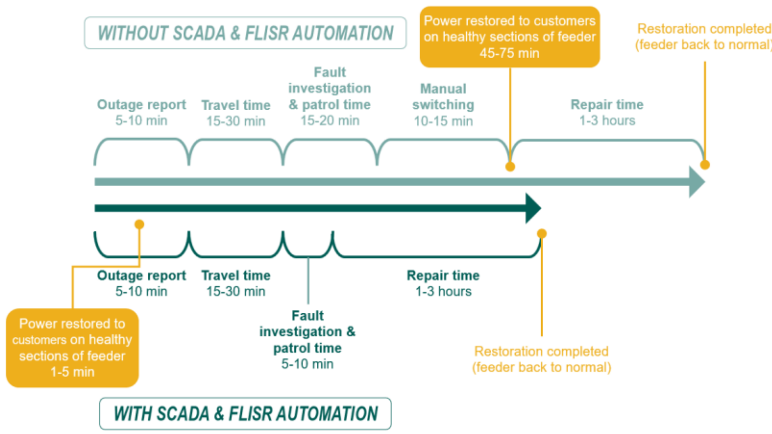


Figure 4: Typical Outage Restoration Times with FLISR VS Without FLISR

In addition, the integration of SCADA switches, reclosers and FLISR has significant benefits and impact on reliability. Figure 5 illustrates the incremental reliability gains for a sustained outage. In the first stage, where only SCADA switches are installed on the feeder, there is no automation and the entire feeder is affected by a fault on the trunk of the feeder. Adding a recloser to the same scenario, automation is introduced and 50 percent of customers will not experience an outage if the fault is downstream of the recloser. In the final scenario, FLISR is implemented in addition to the reclosers and SCADA switches. The three devices will work together to further isolate the fault, activate contingencies and reduce the outage down to 25 percent of the feeder, with the goal of achieving restoration in under one to five minutes.

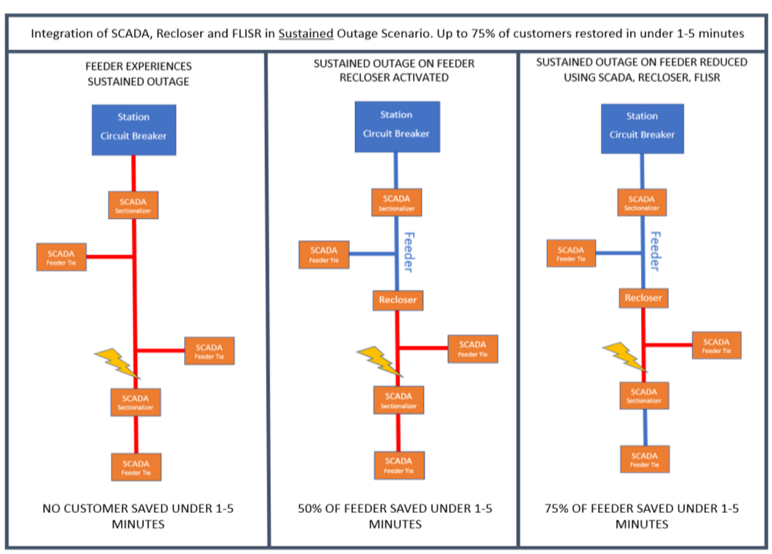


Figure 5: Integration of SCADA, Recloser and FLISR in a Sustained Outage Scenario

Toronto Hydro is focusing the installation of SCADA devices on the trunk feeders on the 27.6 kV distribution network in the Horseshoe area as they have the largest impact on customers. As shown by Figure 6, the 27.6 kV system accounts for the largest share of reliability issues in the system, which also means considerable resources are required to restore outages using manual or remote-operated SCADA switches. Trunk outages interrupt the entire feeder and can impact hundreds to thousands of customers. In contrast, lateral or local outages only impact up to a few hundred customers.

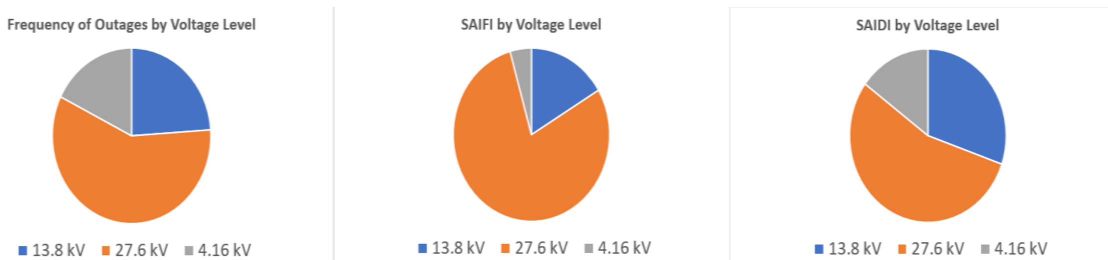


Figure 6: Reliability Impact by Voltage Level – (2018-2022)

Even though trunk outages make up only a third of the outages that occur on 27.6 kV feeders, they can significantly impact SAIFI and SAIDI (as shown in Figure 7 below). The installation of SCADA switches will allow faster sectionalization and restoration of customers in unaffected sections, thereby reducing the impact of trunk outages and improving the reliability of the system.

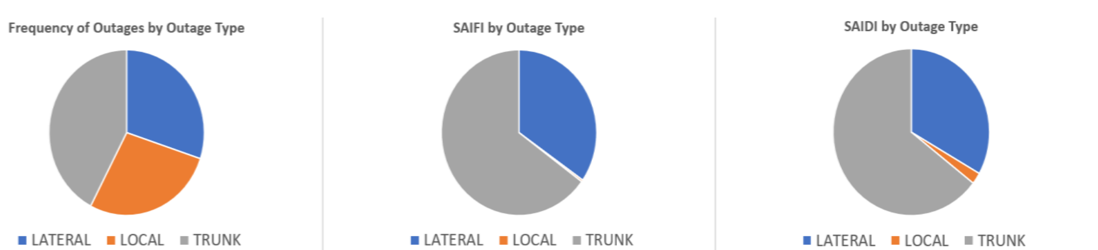


Figure 7: Reliability Impact by Outage Type – (2018-2022)

As of the end of 2022, there are 293 horseshoe feeders of which 230 are considered to be automation ready, defined as having at least two SCADA sectionalizing switches, and at least one SCADA tie point. The switches on these feeders are ready for the implementation of Distribution Automation to realize the full benefits of autonomous restoration. There are 63 Horseshoe feeders that currently do not meet this minimum SCADA switch requirement for Distribution Automation. For these feeders, additional switch installations are required to provide remote restoration capabilities and to enable Distribution Automation to allow for faster outage restorations to customers. During the 2025-2029 period, Toronto Hydro plans to complete SCADA switch installation work on at least 34 of the remaining 63 feeders which will allow all the feeders in the Horseshoe to be able to reap the benefits of Distribution Automation. Ultimately, this will bring the percentage of feeders which meet the Distribution Automation criteria to over 90 percent in the Horseshoe.

The work planned in the Horseshoe area represents the minimum requirement to ensure feeder readiness in support of Toronto Hydro's automatic FLISR schemes. Additionally, the reliability improvements and operational flexibility gained with the proposed plan supports overall performance outcomes related to SAIDI, SAIFI and worst performing feeders. This proposed plan provides the necessary improvements on the Horseshoe feeder trunks and sets the foundation for future system improvements where future SCADA switch installations will provide more visibility and controllability on more specific areas of the system. For example, future opportunities exist to strategically deploy additional SCADA-operated switches:

- To ensure all remaining feeders have no more than 700 customers per section, per Standard Design Practices ("SDP");
- To reduce the number of customers per section in order to reduce customers impacted when a feeder experiences a fault, especially as 700 customers will represent a significant portion of load on a feeder with each customer;
- On riser poles where the main feeder transitions from overhead to underground and vice versa, to increase fault locating capabilities and add the ability to isolate and test reclose if a suspected fault is on the underground segments through targeting approximately 3444 OH-UG Non-SCADA riser points;
- On riser poles at egress cable risers or at the overhead conductor exiting from the station to have the ability to independently remote operate the first switching device and isolate the entire feeder; and
- On riser poles at expressway/highway crossings where high salt contaminated areas exist and SCADA switches have been able to provide much higher operability and are more resilient when compared to manual switches.

2. Installing SCADA-enabled Tie and Sectionalizing Points in the Downtown area

During the 2015-2019 period and 2020-2024 period, the scope of work for Contingency

Enhancement included installing SCADA-enabled tie and sectionalizing switches for the 27.6 kV Horseshoe distribution system in an effort to reduce outage duration and to support Distribution Automation. The Downtown distribution system is inherently more reliable than the Horseshoe since it is predominantly underground and uses supply configurations like Dual Radial which reserves dedicated standby capacity and the Secondary Grid Network which results in no interruptions to customers under contingency. However, the Downtown distribution system does include overhead feeders that are similar to the Horseshoe which is an open loop distribution system. Toronto Hydro anticipates that the impact of outages in Downtown Toronto will be of increasing concern to customers as they become more reliant on electricity thus increasing the need for greater resiliency to the power supply. As determined through Phase I Customer Engagement results, there is generally support among customers for investments in new technology to improve the system.[3] To address these concerns and improve the resiliency of the power supply in the Downtown core, Toronto Hydro plans to expand the scope of Contingency Enhancement investments to include SCADA switch installations on the open loop overhead feeders in the Downtown distribution system.

During the 2025-2029 period, Toronto Hydro plans to install a total of 93 SCADA switches on 40 overhead feeders in the Downtown area. This work is expected to result in an average of approximately 16.3 percent reliability improvement on the 40 feeders where SCADA switch installation work is expected to take place. This will result in average yearly total CMO reduction from 128,499 during the 2018-2022 period to an improved average yearly total CMO of 104,625. The potential SAIDI improvement as a result of this work is expected to be approximately 0.03 minutes per feeder per year.

3. Upgrading undersized loop conductors in the Horseshoe area

Figure 8 depicts a typical looped distribution lateral supplying a series of transformers off the main trunk portion of a feeder. There is an open point near the middle of the loop so that, under normal operating conditions, approximately half of the load in the loop is supplied from one lateral or the other.

[3] See Customer Engagement – Exhibit 1B, Tab 5, Schedule 1

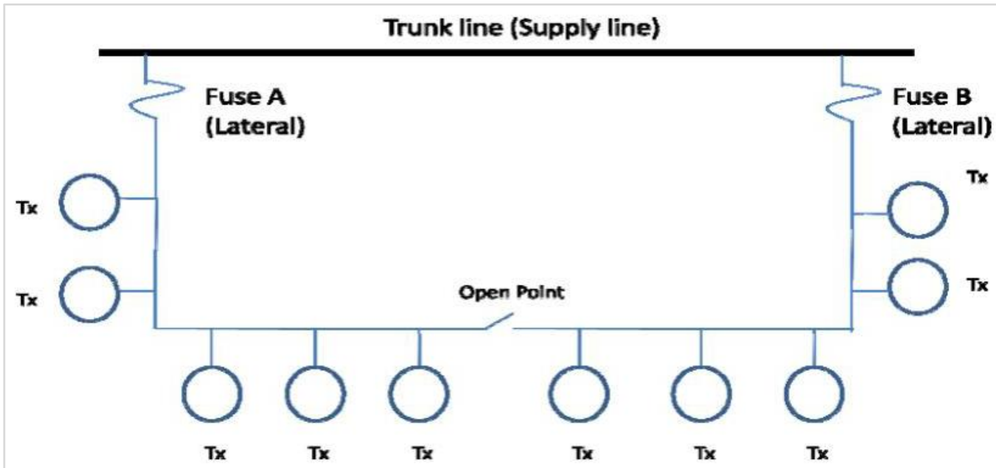


Figure 8: Looped Distribution Design

The conductor on either lateral is designed to be large enough to handle the load of the entire loop if necessary. In a situation where a fault occurs on the first section downstream of Fuse B, the load must be supplied entirely from the other side of the loop, as shown in Figure 9.

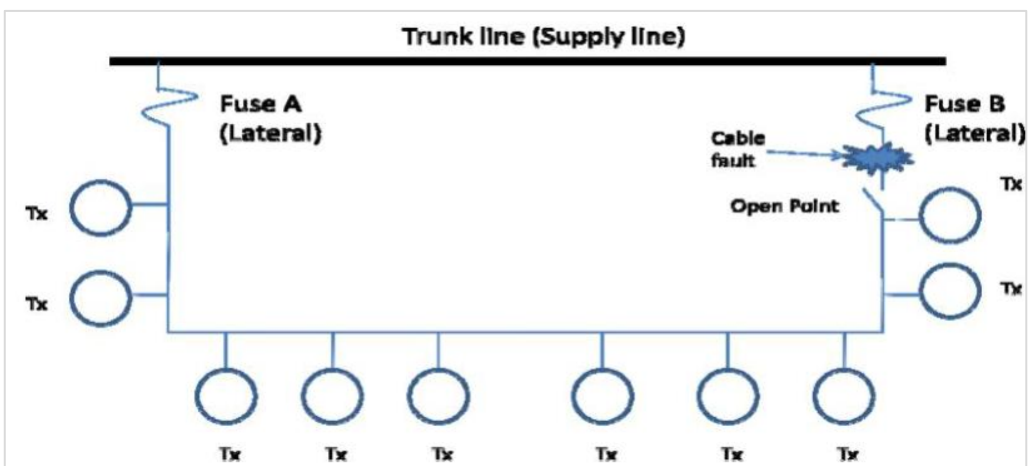


Figure 9: Power restoration in loop after a fault has occurred

Gradual increases in load in certain areas have resulted in existing conductors no longer being able to supply the load of the entire loop. A contingency situation in these locations would cause cascading power outages to the entire loop. Controllers monitor the conductor size and number of transformers transferred to the circuit under contingency; however, the actual load on each transformer may not be known by the controller in real-time.

Toronto Hydro plans to upgrade undersized conductors in lateral loops that are smaller than the utility's standard loop sized conductors during the 2025-2029 period to ensure that they are rated to carry the load of the entire loop under contingency conditions.

3. Upgrading the Capacity of Trunk Egress Cable

Toronto Hydro plans to replace legacy aluminum cable on feeder trunk egress sections with copper cable. The initial section of a feeder, between the station breaker and the first distribution switch (i.e. the section upstream from any load connections), is called the "egress". The egress cable must be adequately sized to supply the load of the feeder, plus any additional load from adjacent feeders under contingency, up to the maximum capacity of the feeder breaker (i.e. 600 A).

Some egress cable installed in the 1960s and 1970s on 27.6 kV feeders is 1000 kcmil aluminum, a cable type that is de-rated (i.e. its current carrying capacity is lowered) when installed in an underground environment, to 500 A in summer and 530 A in winter. In some areas, load growth has exceeded the capacity of this existing configuration. Under contingency, a feeder is required to carry the load of adjacent feeder sections that connect to it. Thus, it is critical that the maximum capacity of the feeder is utilized to restore as many customers as possible. This poses a high-risk situation, as failure of the load-carrying feeder to deliver power to its maximum capacity may result in loss of power to two other feeders, causing outages to a large area for four hours (or more) that it would take to make repairs. Due to the limitation of current carrying capability of these trunk egress cables, customers that would otherwise be served by those feeders under a contingency would experience an outage until the work on their normal feeder has been completed. For these reasons, it is critical that the egress portion of the feeder be fully rated to effectively utilize the rated capacity of the breaker.

Under a contingency condition, controllers may not be able to utilize feeders with a 1000 kcmil aluminum egress trunk cable to pick up load lost on adjacent feeders during a fault or planned maintenance. As a result, affected customers will experience a prolonged power outage until the faulted asset is repaired or replaced on the normal supply feeder. Toronto Hydro may also be required to defer important scheduled maintenance work until the load on feeders is low enough to be re-routed, resulting in the deterioration of asset conditions and further reducing reliability.

As of the end of 2022, there are 11 Horseshoe stations with a total of 88 km of egress cable considered under-rated (i.e. not standard 1000 kcmil copper). Table 4 below shows the amount of under-rated cable for each of these stations. During the 2025-2029 period, Toronto Hydro will prioritize doing work on feeders that have experienced the most customer minutes out over a five-year period and for feeders where the peak loading of their tied feeder is greater than the capacity of the aluminum egress cable. These targeted upgrades and installations will better equip the distribution system to meet the needs of customers in contingency scenarios and more effectively maximize the customer value derived from existing feeders by minimizing unnecessary failure risk.

Table 4. Stations with Under-Rated Trunk Egress Cable.

Station	Under-Rated Egress Cable (km)	Total Egress Cable (Circuit km)
Bermondsey TS	22	23.3
Runnymede TS	1	14.6
Leslie TS	18	23.9
Agincourt TS	7	8.0
Fairchild TS	13	26.5
Bathurst TS	10	48.2
Rexdale TS	3	9.1
Cavanaugh TS	7	13.1
Fairbanks TS	2	9.7
Finch TS	4	20.1
Scarborough TS	1	7.5
Total	**88**	**203.9**

E7.1.3.2 Downtown Contingency

The Downtown Contingency segment is designed to mitigate the risk of high impact, long duration station supply failures. While the likelihood of a long duration loss-of-supply incident occurring in any given station in any particular year is low, these events do continue to occur. Long duration outages are particularly consequential because critical customer loads such as major financial institutions, hospitals and universities are concentrated in the downtown core.

Between 2003 and 2022, there were 34 major outages directly associated with loss of supply incidents. The typical causes of these outages include foreign interference, transmission equipment failure and station flooding. Most recently, on August 11, 2022, a barge moving a crane in an upright position ran into high-voltage transmission lines in the Port Lands. This incident caused three Hydro One power lines to fail causing loss of supply at three Toronto Hydro stations: Esplanade, George &

Duke, and Terauley, impacting 1,633 customers including local businesses, hospitals, office spaces, and the Eaton Centre. All customers were restored within 6.5 hours of the event. The table below outlines other recent examples of loss of supply incidents. The interstation switchgear ties work proposed in this segment specifically targets the stations impacted by the August 2022 incident.

Table 5: Examples of Major Loss of Supply Events from 2003 to 2022

Event	Description
Loss of Supply (July, 2005)	• 115kV pole and line H5E from Hearn failed • 24,572 Customers interrupted • 4,610,141 Customer minutes out • The last customer restored after 18 hours and 50 minutes
Foreign Interference (January, 2005)	• Station flooding due to broken city water main • 3,556 Customers Interrupted • 2,304,288 Customer minutes out • The last customer restored after 10 hours 48 minutes
CB Failure (July, 2012)	• Circuit Breaker failed causing bus differential trip • 4,565 Customers Interrupted • 1,901,191 Customers minutes out • The last Customer restored after 6 hours and 57 minutes
Loss of Supply (August, 2022)	• Loss of Supply due to crane contact with 115kV lines • 11,183 Customers Interrupted • 2,789,920 Customer minutes out • The last Customer restored after 6 hours 34 minutes

Table 6: Downtown Stations at Risk

Downtown Stations	
Basin	Gerrard
Bridgman	Glengrove
Carlaw	Highlevel
Cecil	Leaside
Charles	Main
Copeland	Strachan
Dufferin	Terauley
Duplex	Wiltshire
Esplanade	Windsor

George and Duke	

The period between 2003 and 2022 saw more incidents than the previous decades. As such, to maximize the benefit of investments in the Program, it is appropriate to target the downtown area through the Downtown Contingency segment. To demonstrate the potential reliability benefits of these Downtown Contingency investments, it is helpful to consider the impacts on customer interruption over the 2003-2022 period had full Downtown Contingency been in place during that period.

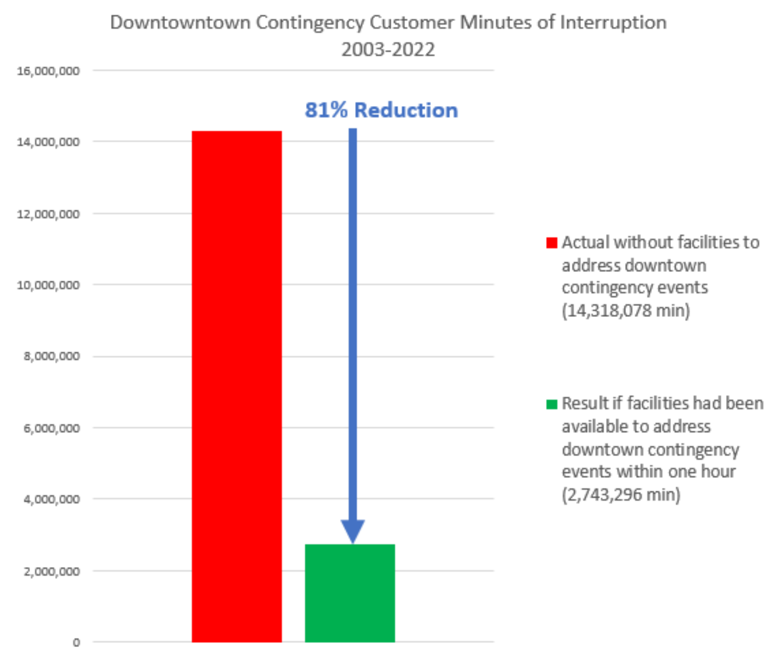


Figure 10: Reliability impact of downtown station load transfer implementation

The operationalization of a Downtown Contingency program with the ability to pick-up customer loads from another station within one hour, could result in an approximately 80 percent reduction in Customer Minutes of Interruption caused by such incidents.

Following the occurrence of downtown contingency incidents, Toronto Hydro analyzes the cause and undertakes projects in an effort to minimize the risk of reoccurrence. Examples of station improvements include: hardening station facilities and equipment to be able to withstand externally and internally-driven failure modes, additional sensors and alarms that can identify developing incidents at the earliest opportunity, and high-volume sump pumps that can address major water entry incidents such as city water main breaks. As a result, the risks of long duration station supply failures have continued to drop over time. However, although these projects reduce the risks, they often cannot be entirely eliminated. Risks outside of Toronto Hydro's control, such as the recent crane contact with Hydro One lines incident, will therefore cause an increasing proportion of long duration station outage incidents in future years. Concerning the nineteen long duration outage events in 2002-2022 that could be addressed by downtown contingency enhancements, sixteen were due to causes outside of Toronto Hydro's control, or approximately 84 percent.

Contingency enhancement options include a variety of methods to install ties between stations. Including:

- Interstation switchgear ties (i.e., ties between buses in different stations)
- Intrastation switchgear ties (i.e., ties between buses in the same station)
- Interstation feeder ties
- Automated Primary Closed Loop (APCL) ties

Ideally, each station switchgear would have sufficient emergency loading capability to pick-up all, or most, of an interconnected switchgear's load. In addition, each station would also ideally be connected to a different Hydro One source of supply.

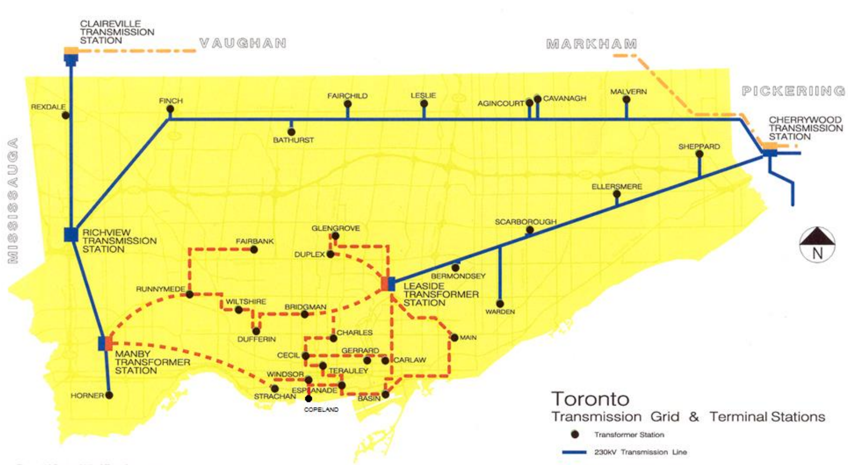


Figure 11: Map of Toronto stations with Hydro One transmission connection

To achieve these benefits, Toronto Hydro has chosen the medium-term plan to provide interstation switchgear ties.

The proposed ties will cover the stations that were impacted by the 2022 crane contact incident, where the best option for an anchor downtown source is Copeland Station. This station has a switchgear designed for load transfer purposes, as well as an extra transformer available for emergencies. Additionally, future plans include replacing the initial 115 kV transmission connection with a 230-kV connection. This means that Copeland Station will ultimately have a Hydro One source of supply well-separated from those supplying all other nearby downtown stations. When combined, these factors make Copeland Station by far the best choice for an anchor source in the downtown area.

E7.1.3.3 System Observability

An important component of Toronto Hydro's *Intelligent Grid* strategy for 2025-2029 is the targeted deployment of technologies that will enhance grid transparency. An overview of these investments is provided in the System Observability category of the utility's Grid Modernization Roadmap (See Exhibit 2B, Section D5). From a materiality perspective, the most significant investment Toronto Hydro is making to enhance grid transparency in the 2025-2029 period is the replacement of end-of-life, legacy smart meters with next generation smart meters ("AMI 2.0").[4] AMI 2.0 has the long-term potential to provide many of the high frequency, multi-parameter insights that will be required to address the operational pressures and requirements expected as electrification and DER proliferation ramps-up. However, many of the potential benefits and use cases for AMI 2.0 are currently untested and will require significant investment in incremental data analytics, digital systems integrations, and business process changes. It is not yet apparent which of these potential AMI-based solutions will prove to be more economical and sustainable as compared to more use-case-specific grid sensor technologies which are currently more proven and available. In light of this uncertainty, and in the interest of providing immediate benefits to customers while diversifying the long-term options available to Toronto Hydro for monitoring the system, the utility is introducing the System Observability segment for 2025-2029.

This segment will involve the strategic deployment of sensors that will provide the utility's planners and grid operators with real- or near-real time insight into asset performance and operating conditions at critical points on the grid. These capabilities will provide Toronto Hydro with two primary benefits: enhanced response capabilities through the use of fault finding sensors and other

[4] For more details about Toronto Hydro's AMI 2.0 investments, please refer to the Metering program in Exhibit 2B, Section E5.4

telemetry; and the ability to make more effective capital investment and maintenance planning decisions.

To achieve these benefits, the System Observability segment will deploy several sensory assets, such as overhead and underground powerline sensors, online cable monitors, and transformer monitors.

1. Overhead and Underground Sensors

Overhead and underground sensors can improve Toronto Hydro's outage response time. As of today, Toronto Hydro depends in large part on customers to notify the utility when there is a localized outage. The most impactful use-case for grid sensors is that they can eliminate extra steps in the process by alerting the control room to an outage in real time so the utility does not have to wait for notification from a customer. With the mature directional sensor capabilities that are now available, Toronto Hydro can cost-effectively introduce and expand visibility to parts of the grid where it has not traditionally been available.

Additionally, overhead and underground sensors enable controllers and dispatch crews to narrow locations of faults, effectively reducing outage response times. They may also aid in helping verify the cause of outages. As a subsequent need, overhead and underground sensors and monitors provide data that enable Toronto Hydro to record information for diagnostic purposes and drive towards proactive asset management to improve SAIFI & SAIDI metrics. Data can also be extracted to find core failure causes and address them proactively. Figure 12 illustrates sensors on overhead lines that could be part of the System Observability investments.

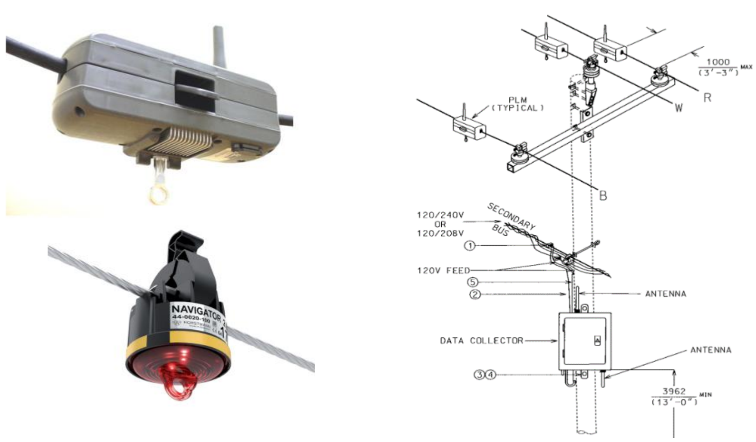


Figure 12: Illustration of Sensors on Overhead Lines

2. Online Cable Monitoring

Online Cable Monitoring utilizes distributed temperature sensing (DTS) technology to obtain a continuous temperature profile of fiber optic cables that are placed alongside underground cables. This information will enable operations and planners to understand feeder loading, increase asset utilization, and identify hot spots. Online Cable Monitoring would allow for proactive measures to be taken on cables such as identifying cables that could be at risk of failure before failure or costly to inspect otherwise. Furthermore, Online Cable Monitors allow for monitoring of load growth and for Toronto Hydro to proactively address and prioritize capacity availability. Lastly, Online Cable Monitors would save OPEX costs and planned outage times when it comes to cable testing and diagnostics. Toronto Hydro plans to deploy Online Cable Monitoring using DTS to complement diagnostic testing as part of Toronto Hydro's cable testing program in order to achieve a better understanding of the overall underground cable system. Currently, limited and targeted cables go through a lengthy and manual testing process of partial discharge which has been cumbersome. Figure 13 illustrates example online cable monitoring devices that could be part of the System Observability investments.

Figure 13: Illustration of Online Cable Monitoring Devices

Online cable monitoring may be deployed in parts of the distribution system that have physical constraints and associated processes to access. One example includes assets within the Western Gap Utility Tunnel bridging Toronto Island to Toronto mainland where cables are located in a tunnel that is pressurised with lake water, making it costly to inspect or maintain.

3. Transformer Monitoring

With the increasing rate of adoption of electric vehicles and increases in residential density in the City of Toronto, there is more pressure due to higher load demand on Toronto Hydro's secondary distribution system. Transformer monitoring allows Toronto Hydro to gain more accurate, real-time loading on the transformer instead of aggregating customer meter loading. The data these devices provide will help improve design requirements when considering new and existing secondary distribution systems. These monitors are also expected to help improve the understanding on the impact of unmetered services on the secondary distribution system to refine connection strategies. The data obtained will also help refine asset management strategies for distribution transformers and optimize their usage and life. An example transformer monitor is shown in Figure 14.

Figure 14: Illustration of a Transformer Monitoring Device

The System Enhancements program segments work together towards the goal of achieving Toronto Hydro's vision of an Intelligent Grid. The continued implementation and enhancement of the Contingency Enhancement segment and the introduction of the System Observability segment specifically contribute to the Intelligent Grid components shown in Figure 15. As key components of the Intelligent Grid, being able to fully implement the System Enhancements program is essential to the overall success of the Intelligent Grid initiative.

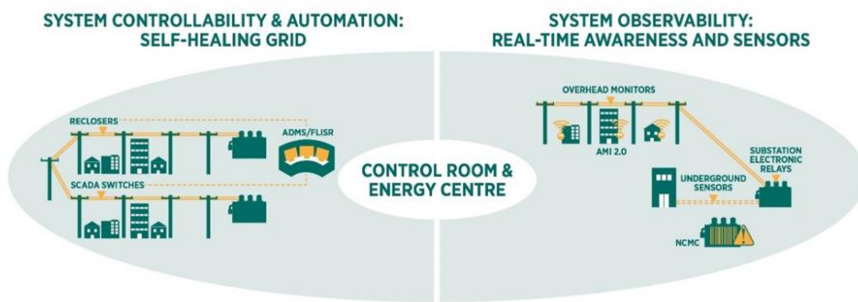


Figure 15: Intelligent Grid Components

E7.1.4 Expenditure Plan

To meet its objectives for an intelligent grid, Toronto Hydro plans to invest $151.2 million over the 2025-2029 period in the System Enhancements program.

Table 6: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Contingency Enhancement	5.0	0.8	4.9	3.7	5.5	17.0	19.6	32.0	29.0	35.3
Downtown Contingency	-	3.7	1.7	-	0.1	1.7	2.9	2.9	3.0	3.1
Customer-Owned Substation Protection	-	0.7	0.1	-	-	-	-	-	-	-
System Observability	-	-	-	-	0.1	0.8	0.9	1.0	1.0	1.0
Total	**5.1**	**5.1**	**6.7**	**3.7**	**5.7**	**19.6**	**23.3**	**35.9**	**33.0**	**39.4**

E7.1.4.1 Contingency Enhancement

1. 2020-2024 Variance Analysis

Toronto Hydro invested $10.7 million in the Contingency Enhancement segment from 2020-2022 period and is projected to allocate an additional $9.2 million in 2023-2024, totalling $19.9 million. This is 25.1 percent lower than the initial proposal outlined in Toronto Hydro's 2020-2024 Distribution System Plan ($24.9 million).

Due to the necessity of installing connections between Copeland TS and Windsor TS in the 2020-2022 period, $5.5 million from the Contingency Enhancement segment was reallocated to Downtown Contingency (see variance analysis below). As a result, planned cable upgrades at Bermondsey TS, Fairbank TS, and Leslie TS were deferred to the 2025-2029 rate period. These entail the replacement of over 4,000 meters of aluminum egress cable with the latest standard copper cable.

Between 2020 and 2022, Toronto Hydro added tie points to 5 feeders, sectionalizing points on 9 feeders, and upgraded one undersized lateral loop. These investments brought 3 feeders up to the minimum Standard Design Practice for operating contingency and prepared three additional feeders for Distribution Automation. Note that a typical Horseshoe feeder serves between 1,400 and 6,000 customers.

For 2023 and 2024, Toronto Hydro plans to install tie points on four distribution feeders and sectionalizing points on three feeders.

2. 2025-2029 Proposed Plan

Toronto Hydro intends to invest approximately $132.9 million in Contingency Enhancement projects during the 2025-2029 period. This increase in expenditure, relative to the 2020-2024 levels, is informed by customer priorities for reliability where they indicated outage durations, particularly during extreme weather events, to be of high importance. Small business and residential customers, in particular, expressed a strong preference for investment in new technology.[5]

Therefore, over the 2025-2029 period in total, Toronto Hydro plans to install approximately 300 SCADA switches (at a pace of 60 per year) on feeders across the Horseshoe and Downtown area with the highest total Customer Minutes Out ("CMO") during the latest 5-year period. As stated in Section E7.1.3.1, this is intended to achieve a total of 18 percent improvement in reliability across 90 Horseshoe feeders and 29 percent on 40 Downtown feeders. This will ensure the remaining 63 Horseshoe feeders meet the distribution automation requirement, thus enabling Toronto Hydro's Grid Modernization objectives.

Specifically, Toronto Hydro plans to install a total of 205 SCADA switches on 94 feeders in the Horseshoe area. This work is expected to result in an average of approximately 12.6 percent

[5] *Supra* note 3

reliability improvement on the 94 feeders where SCADA switch installation work is expected to take place. This will result in average yearly total CMO reduction from 180,113 during the 2018-2022 period to an improved average yearly total CMO of 162,889. The potential SAIDI improvement as a result of this work is expected to be approximately 0.022 minutes per feeder per year.

Furthermore, Toronto Hydro plans to install a total of 94 SCADA switches on 40 overhead feeders in the Downtown area during the 2025-2029 period. This work is expected to result in an average of approximately 16.3 percent reliability improvement on the 40 feeders where SCADA switch installation work is expected to take place. This will result in average yearly total CMO reduction from 128,499 during the 2018-2022 period to an improved average yearly total CMO of 104,625. The potential SAIDI improvement as a result of this work is expected to be approximately 0.03 minutes per feeder per year.

In addition, this investment option plans to install 220 modern reclosers in the distribution system which will yield improved service reliability, a reduction in CMO and CI, and operational efficiency advantages over fault management as stated in Toronto Hydro’s Grid Modernization Roadmap (Exhibit 2B, Section D5).

Moreover, this investment initiative will replace approximately 70 km of undersized cable which makes up approximately 80 percent of the total existing undersized egress cables in the Horseshoe area where the peak loading under contingency situation exceeds the capacity of the aluminum egress cable.

Investments made within this segment will be prioritized on the basis of historical reliability performance, loading statistics, cost-benefit analysis, and other relevant data.

E7.1.4.2 Downtown Contingency

In the 2015-2019 rate period, Toronto Hydro's Downtown Contingency program provided station level contingency through load transfer capabilities between stations in the downtown area to mitigate loss of supply risks. Toronto Hydro successfully completed a number of overheard feeder ties, but upon re-evaluating the costs and challenges associated with underground feeder ties, the utility decided not to pursue additional work in this program. However, over the 2020-2022 period, Toronto Hydro spent $5.5 million and installed interstation switchgear ties between Copeland and Windsor stations due to the need to provide contingency mitigation in the downtown core. This work enabled:

- Contingency mitigation at Copeland TS due to the need for transformer repair. These bus ties ensured that should an equipment failure occur, customers supplied by Copeland would not experience an extended power outage.
- Transfer load from Windsor station switchgear to enable switchgear upgrade projects. This work will require the Copeland to Windsor ties to be modified multiple times in the near future. These will provide downtown contingency capability between Copeland and Windsor stations in the long-term.

Recent loss-of-supply incidents have resulted in Toronto Hydro proposing an interstation switchgear tie project from Copeland Station to Esplanade Station over the 2025-2029. The Copeland-Esplanade project work will progress from inspection to design to civil construction and finally electrical construction. Following this window, additional options should become available and are discussed in the next section.

E7.1.4.3 System Observability

The System Observability segment is a new segment with no planned investments in the 2020-2024 DSP. However, Toronto Hydro now plans to spend approximately $0.1 million in 2024 to start installing sensors and monitors before ramping up to $0.9 million per year on average over the 2025-2029 period.

Over the 2020-2022 period, Toronto Hydro assessed a number of overhead and underground sensors and monitors. Over the course of 2023 and 2024, the utility intends to issue a request for proposal to evaluate and select the technology best suited for Toronto Hydro's system.

Once completed, these sensors and monitors will be installed on the overhead and underground system during the 2025-2029 period at a steady pace with ramp up starting in 2024. Priority would be given to areas that are forecasted to increase in load (such as Electric Vehicle growth, electric heating, etc.) and in areas that inspections are costly such as the Western Gap Utility Tunnel bridging Toronto Island to Toronto mainland where cables are located in a tunnel that is pressurised with lake water.

The utility also plans to pilot transformer monitors to validate transformer readings in order to support planning analyses and enhance policy planning decisions. Toronto Hydro intends to pilot transformer monitors across the City of Toronto in various settings to obtain samples of data that are representative of the many different scenarios. The results of the pilot and additional functionality determined will drive future plans and expenditures.

E7.1.5 Options Analysis

E7.1.5.1 Options for Contingency Enhancement

1. Option 1: Contingency Enhancement at Current pace

Under this option, Toronto Hydro would continue investing at the current pace to spend approximately $20 million over 2025-2029. This would severely limit the scope of work that can be accomplished. Toronto Hydro would have to prioritize only the most critical Contingency Enhancement investments, such as installing 111 SCADA switches for 37 of the feeders in the Horseshoe with the worst reliability and approximately 17.8 km of undersized egress cable upgrades for 7 feeders. The utility would not be able to install SCADA switches on a portion of the Horseshoe feeders that currently fail to meet the minimum Distribution Automation requirement or on overhead Downtown feeders. This option also excludes the implementation of modern reclosers in the distribution system and any upgrades of undersized loop conductors.

Under this option, the utility's ability to reduce the number of customers impacted and outage duration during contingency events would be limited. Moreover, the absence of strategically placed reclosers would leave Toronto Hydro's assets susceptible to damage and strain during system faults. Without the fault testing capabilities provided by recloser features, Toronto Hydro would be constrained in its ability to proactively prevent faults. Considering these factors, the status quo is not recommended.

2. Option 2 (Selected Option): Contingency Enhancement

Executing the proposed Program would strengthen Toronto Hydro's distribution system in contingency conditions, improving reliability for affected customers. The addition of SCADA controlled tie and sectionalizing switches would enable Toronto Hydro to segment a feeder into smaller sections, transferring load to alternate feeders and minimizing the duration of power outages. This investment option entails upgrading approximately 300 SCADA switches for 94 Horseshoe feeders and for 40 Downtown feeders. Furthermore, 44 feeders will be targeted for upgrading undersized egress cables from aluminum to copper, replacing approximately 69 km of cable. These enhancements align with Toronto Hydro's Grid Modernization plan, ensuring that 90% of Horseshoe feeders meet the Distribution Automation requirement by the end of the period.

Additionally, this investment option will include implementing 220 modern reclosers in the distribution system that will yield improved service reliability, a reduction in Customer Minutes Out (CMO), and operational efficiency advantages over fault management. By targeting high-priority locations and responding to customer concerns, Toronto Hydro will enhance its ability to restore power quickly during outages, especially in the Horseshoe and Downtown areas, including high-impact contingency events. This option offers short-term and long-term benefits, directly benefitting customers and prolonging the life of system assets. Therefore, this option is highly recommended as it strikes a balance between mitigating risks and meeting customer expectations. It aligns with Toronto Hydro’s Grid Modernization goals.

E7.1.5.2 Options for Downtown Contingency

1. **Option 1: Maintain the status quo**

This option maintains the system at status quo. Projects would continue within the Stations portfolio to eliminate downtown reliability risks and to install new equipment which meet the latest standards; reducing vulnerabilities and improving flexibility in emergency situations. Distribution projects that allow customer load transfer between stations during major station outages will be pursued. While these investments would improve reliability risks within the system, they do not mitigate contingency event scenarios. And therefore, this option is not recommended.

These ongoing incremental improvements will continue into the future regardless of other options being undertaken.

2. **Option 2 (Selected Option): Station-to-Station switchgear ties (i.e. interstation switchgear ties)**

This option involves the installation of station-to-station switchgear ties on eligible stations with the required 3000A feeder positions present. Each station switchgear should have sufficient emergency loading capability to pick-up the majority of an interconnected switchgear’s load. Additionally, each station should be connected to a different Hydro One source of supply. This option is the selected option as it would provide the quickest timeline to achieve reliability benefits, while accommodating operational constraints.

As noted in E7.1.3.2, the best option for an anchor downtown source is Copeland Station.

3. Option 3: Station-to-Station feeder ties

This option involves the installation of station-to-station *feeder* ties, and would need to continue into the future in order to maximize benefits. It requires a long time to achieve the stated benefits compared to the previous options. However, the result would provide more benefits.

The feeders should have sufficient emergency loading capability to pick-up the majority of the neighbouring feeder's load and a different Hydro One source of supply. There are approximately 557 feeders in the downtown area suitable for feeder ties, of which 26 have already been tied.

To complete the required feeder ties in a reasonable time frame, this option requires installation of approximately 11 feeder ties annually, for a period of approximately 25 years.

Feeder ties provide limited ability to pick-up loads; therefore, if required, the Control Room would have to select the loads to pick-up out of the options available. The Control Room would be required to prioritize loads such as hospitals, water and sewage treatment, and key financial centers.

Interstation feeder tie projects were undertaken in the 2015-2019 period, but were found to have escalating costs and challenges as noted in 2020 CIR (Section E4.2.3 at, pg. 12-13). Due to the relatively high costs for the benefits achieved, this option is not recommended.

4. Option 4: Switchgear ties within the same station (i.e. intrastation switchgear ties)

This option involves the installation of direct bus ties between switchgears in the same station. These ties can be used to resupply a Toronto Hydro station switchgear that has lost its Hydro One supply, from another Toronto Hydro switchgear within the same station that continues to be supplied by Hydro One.

This work is in the Stations portfolio and will not be undertaken in the downtown contingency segment. In this option, when existing Toronto Hydro station switchgear are replaced, the new switchgear includes provisions for direct bus ties to other switchgear within the same station.

5. Option 5: Automated Primary Closed Loop ties (i.e. APCL ties).

The Automated Primary Closed Loop ("APCL") option provides the most substantial long-term improvements of all the options. It also increases development risks and challenges.

This option involves the installation of station-to-station *feeder* ties. Unlike Option 3, this option involves the addition of components to tie future APCL distribution systems supplied by two different stations. APCL equipment and system design are currently in development, with no plant presently installed in the field. Over the 2023-2025 period, the first prototype APCL vault equipment is expected to be acquired and will be used to develop and test protection and control, as well as operational practices. APCL ties provide fundamentally more cost effective and operational benefits than other options.

This option requires a longer timeline to achieve a specified level of benefits than other options. However, it would achieve more benefits at a lower cost. Ultimately, APCL will not be achievable in the 2025-2029-time frame, but will be considered for future distribution system plans.

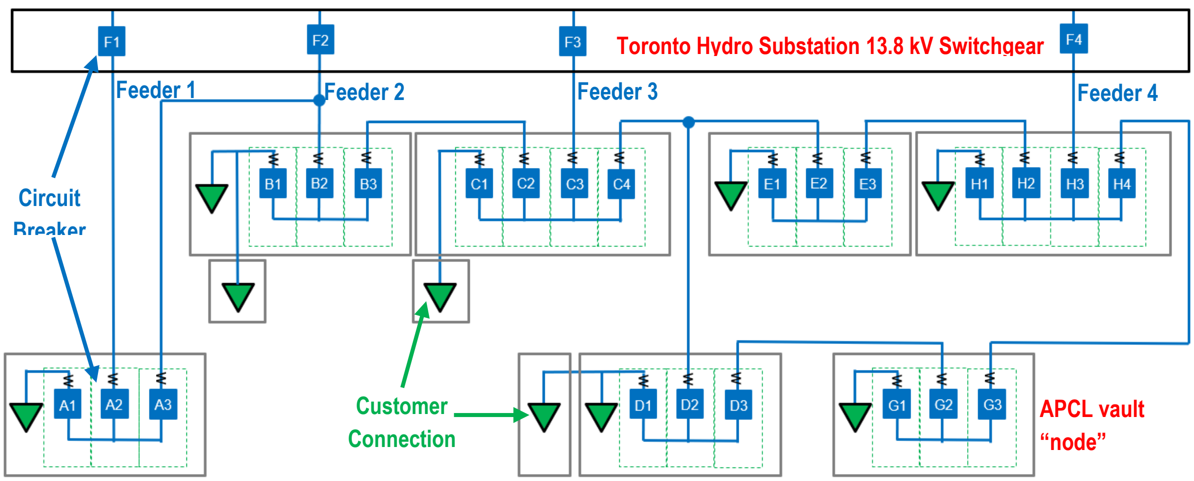


Figure 16: APCL Distribution System

E7.1.5.3 E7.1.5.3 Options for System Observability

1. Option 1: No Installation of System Observability Assets

The present circumstances, being a system without visibility on live data, is costly and timely to customers when it comes to outage restoration. Acknowledging that proven technology is readily available, the existing costs and existing average outage durations are avoidable and capable of being reduced. Without the thermal profiles and partial discharge identifying capabilities through online cable monitors, proactive measures cannot be taken which are costly and preventable. The current system waits for cables to fail and then Toronto Hydro reacts accordingly which is costly and untimely. For these reasons, this option is not recommended.

2. Option 2 (Selected Option): Installation of System Observability Assets

Installing monitoring devices onto Toronto Hydro's existing system will enable visibility on the electrical grid at strategic locations and would be a win-win for customers and Toronto Hydro, and is the recommended option. Observability would provide reduced outage times, extended asset life and improved planning in many cases. Costs can be reduced by less time identifying the fault and less wear-and-tear on equipment that occurs during fault. Without observability assets, manual inspections are undertaken which may not be frequent or sufficient to identify developing issues prior to failure. Online cable monitors and transformer monitors provide a paramount overview of risk failure. This initiative for visibility on faults coupled with communication to Toronto Hydro's controllers and crews is the recommended option.

E7.1.6 Execution Risks & Mitigation

E7.1.6.1 Contingency Enhancement

Unforeseen site conditions, such as the presence of third-party infrastructure (e.g. gas, sewer or water pipes), can necessitate scope changes, and result in cost increases or delays in the completion of the underground cable replacement Contingency Enhancement work. In these situations, Toronto Hydro will reprioritize or reschedule work after taking all factors into consideration.

As well, Toronto Hydro must consider city road moratoriums. Underground cable replacement work which is part of this segment might come in direct conflict with city-imposed road moratoriums. This could delay any civil infrastructure installation required for cable upgrades which will delay the Contingency Enhancement projects. Toronto Hydro will mitigate this risk by ensuring that it maintains open communication with the City of Toronto and coordinates its activities with those of the city.

Distribution Automation projects, by their nature, require robust communication between SCADA switches. Under the proposed centralized approach (FLISR) utilizing the NMS, this risk will be mitigated.

Supply chain challenges is a new risk that Toronto Hydro is currently experiencing where many of the vendors cannot provide material and equipment on time to ensure timely execution and completion of Contingency Enhancement projects. This can be mitigated by working closely with the supply chain team to order as much of the required material in advance, and to reprioritize the order of which projects get executed each year to minimize disruption to the work program for this segment during 2025-2029 period.

Based on Toronto Hydro's recloser pilot, reclosers require coordination with HONI, System Studies, and Operations to make the reclosers coordinate and operate properly. Without proper coordination between the station circuit breaker and the recloser, there is a risk that both devices will trip resulting in minimal benefits from the recloser. Modern reclosers compatible with Toronto Hydro's system require microprocessor relays at the station to properly set the coordination of the relays. Feeders that meet the criteria for more than one recloser on the feeder, fibre optic communication provisions may be required for coordination and proper operation. Without fibre optic infrastructure connected from the station breaker to the recloser, the feeder may be limited to a maximum of one recloser due to coordination limitations. Hence, the plan may include a two-phase approach of installing reclosers on poles and then adding fibre optic in a subsequent phase or vice versa depending on feeder, station coordination and existing infrastructure.

E7.1.6.2 Downtown Contingency

Unforeseen field conditions, equipment configurations and new standards and materials will impact the station-to-station switchgear ties program. These include, but are not limited to, the following:

- Running new ducts in downtown congested areas: Underground civil structures have been utilized and/or constructed over the last several years. Additional civil plant will likely need to be constructed in congested areas, which may create unanticipated project delays and cost escalation. In addition, recent experience has shown increased civil cost and project delays due to very high-water tables near the waterfront

- The new switchgear requires a swing option. Generally, station-to-station switchgear ties require new switchgears with appropriate configuration. If a new gear is not available at the time of the tie project, project delays will occur. Project plans should ideally be based on suitable existing switchgear. Alternatively, projects should be only planned where there is high confidence that the switchgear will be ready when required

- Furthermore, station-to-station switchgear tie projects are expected to require new cabling, jointing and termination standards. Changes to standards should be addressed as soon as requirements can be firmly established.

- Finally, the response strategy to manage moratoriums and obstacles includes; reschedule civil construction work to avoid moratorium time periods, and redirect duct bank routes to avoid areas under construction moratoriums.

E7.1.6.3 System Observability

Overhead and underground sensors provide real time data which requires consideration for communication infrastructure. Current market products that have been proven and utilised in other Canadian power utilities to date include the use of SIM cards for communications. Considerations for network connectivity and coverage must be tested in advance of installation. In a previous Toronto Hydro study of 32 power line monitors, they all became obsolete after telecommunication networks advanced from the 2G network to the 3G and 4G networks. This significantly reduces the asset's useful life and return on investment. Compatibility with Toronto Hydro's current SCADA and FLISR systems will be considered along with overhead and underground sensors such that they can adapt with changing communication networks or be independent of them entirely. Additionally, some overhead and underground sensors within the current market require their own independent power sources. Top current market products show that the majority require DC power or batteries that may require replacing or charging. Visibility of battery life and signal strength of sensors would be major considerations to mitigate operational risks. Furthermore, risk considerations of extreme weather and extreme high/low Toronto temperatures along with instrument calibration would be realistic risk factors for these measuring assets. To mitigate these risks, data from the manufacturers and other utilities would be considered during the Request for Proposal stage which is planned for in 2023.

Online Cable Monitors will require fibre communication infrastructure to attain live data. Coordination and planning will be required prior to the installation of Online Cable Monitors especially in locations that do not presently have fibre communications that have been identified as an optimum location for an Online Cable Monitor. To mitigate the risk of not having the Online Cable Monitors installed in the most optimum locations, planners and operational controllers will need to ensure that fibre communications is installed prior to the Online Cable Monitors. Part of the strategy is to consider installing Online Cable Monitors where fibre optic already exists and then expand to areas that are fibre optic feasible.

The current market for Transformer Monitors may require a separate software for access to the live data being acquired. Lack of integration with the FLISR system is a risk as it may hamper the operational benefits if there are separate systems. To mitigate this, product selection must include customised or retrofitted integration to experience the full benefits on operations.

Lastly, integration of new technology into the current Toronto Hydro system will require IT support and vendor support. Accessing real-time data during a power interruption will require fundamental integration into the current software systems to achieve optimum use of the data.

E7.2 Non-Wires Solutions Program

E7.2.1 Overview

Table 1: Program Summary

Total 2020-2024 Cost ($M): $2.2	**2025-2029 Cost ($M): $22.5**
Energy Storage Systems 2020-2024: $1.2	Energy Storage Systems: $ 22.5
Local Demand Response 2020-2024: $1.0	Flexibility Services: OPEX only
Segments: Flexibility Services, Energy Storage Systems	
Trigger Driver: Capacity	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Financial Performance, Public Policy Responsiveness	

Toronto Hydro has been actively exploring how Non-Wires Solutions (NWSs) can support conventional utility planning since 2015, primarily through the Local Demand Response (LDR) program (now included in the Flexibility Services segment), but also through the deployment of grid-supporting Energy Storage Systems (ESS). In previous years, these two programs have been managed separately; going forward, they will be brought together under one Non-Wires Solutions program.

NWSs refer to operating practices, activities or technologies that enable the utility to defer the need for specific distribution or transmission projects, at a lower total resource cost, by reliably reducing system constraints at times of maximum demand in specific grid areas. Typically, these NWSs leverage the use of Distributed Energy Resources (DERs), often in partnership with utility customers, or with other enabling third-parties.

The NWS strategy for the 2025-2029 period is focused on being flexible and adaptable to help system planners respond to load growth while navigating the underlying uncertainty that stems from changing demand patterns and increased reliance on electrification. This strategy builds on Toronto Hydro's experience utilizing DERs to reduce peak demand, helping to defer grid expansions or, in most cases, avoid grid expansions should demand not materialize as expected (e.g., lower than expected demand, fluctuating demand). This approach can help utilities meet system needs while avoiding overbuilding, ultimately reducing the risk of stranded or underutilized assets. Given the scale of investment that will be required to meet high-levels of electrification, NWSs are viewed as additive to conventional utility expansion strategies, enabling Toronto Hydro to expand its planning toolbox to include additional strategies for keeping up with load growth.

The NWS program at Toronto Hydro has two broad streams:

1) **Flexibility Services**

   Flexibility Services at Toronto Hydro refers to programs that address localized distribution issues through targeted procurements with customers or other third-parties. The most well-established flexibility service program at Toronto Hydro is LDR, which has been running since 2015. For the 2025-2029 period, Flexibility Services will be expanded beyond standard 4-hour Demand Response (DR) to include other services that can address a demonstrated grid-need, such as shorter duration DR where appropriate.

2) **Energy Storage Systems**

   Energy Storage Systems at Toronto Hydro are an innovative tool to complement traditional utility technologies in addressing distribution grid challenges. For the 2025-2029 period, Toronto Hydro will focus on developing a scalable, demand-driven, ESS strategy that is responsive to distribution system needs and supports the pathway to renewable integration and electrification

Toronto Hydro's NWS strategy for 2025-2029 reflects the last eight years of experience in both LDR and the energy storage space. The vision for the future is a product of experience and reflection, resulting from facing and overcoming numerous challenges. The program is unique in that in contains both capital expenditures (ESS equipment), as well as operating expenditures (capacity or energy payments for DR capacity). These expenditures are outlined below.

E7.2.1 Flexibility Services

E7.2.1.1 Background and Future Vision

Toronto Hydro's vision for flexibility services is built upon its strong foundation of successfully deploying NWSs. Toronto Hydro, a leader in developing NWSs, intends to continue to evolve the opportunities and benefits afforded by NWSs.

Local Demand Response Overview

The LDR program is Toronto Hydro's flagship NWSs initiative. The LDR program was the first utility-driven NWS program in Ontario and has been deployed successfully since the 2015-2019 rate period. This program is designed to help address short-to-medium term capacity constraints at targeted transformer stations by identifying opportunities where DR, including behind-the-meter and customer-owned DERs, can be leveraged to support the broader distribution system cost-effectively.

The LDR program is a big step forward in evolving conventional utility station planning to include the consideration of NWSs alongside traditional "poles and wires" investments. This approach enables the utility to address capacity constraints using targeted deployment of DR, expanding the planning toolbox beyond conventional wires solutions when evaluating options to address short-to-medium term capacity needs.

Utilities regularly utilize information and data to prioritize infrastructure investment based on where the system needs it the most. Demand Response strategies can provide utilities with increased flexibility when determining which projects should be undertaken, which ones can be deferred to a later date, and which ones can be avoided entirely, ensuring optimal allocation of limited capital funds. This results in a more efficient use of capital, and in some instances, leads to avoiding capital expenditure all-together.

Since launching LDR in the 2015-2019 rate period, Toronto Hydro has demonstrated the ability to procure and deploy contractual DR capacity to support the grid. This experience has helped develop and grow capabilities in utilizing NWSs.

During the 2015-2019 period, Toronto Hydro ran LDR at one station located in the downtown core: Cecil TS. At the time, the utility was forecasting that capacity constraints would materialize on two busses at Cecil TS in 2020. Toronto Hydro used LDR to reduce summer peak demand by about 8 MW, helping to avoid anticipated capital investment. The anticipated capital investment was initially deferred to the 2025-2026 period. However, these upgrades were avoided entirely, as the load profile at Cecil TS evolved over the 2020-2022 period, resulting in a much different outlook which no longer necessitated station expansion. This pilot project is an example of how a utility can leverage customer-owned DERs to gain planning flexibility when dealing with investment needs that carry a high degree of uncertainty.

The Cecil TS LDR Pilot at a glance:

- Successfully contracted 8 MW of DR, working with commercial and institutional customers
- Reduced summer peak demand by 8 MW in 2018 and 2019
- Resource mix included back-up behind-the-meter generation and customer load curtailment activities
- 5-6 events per year, delivered over a 4-hour period (2pm to 6pm)

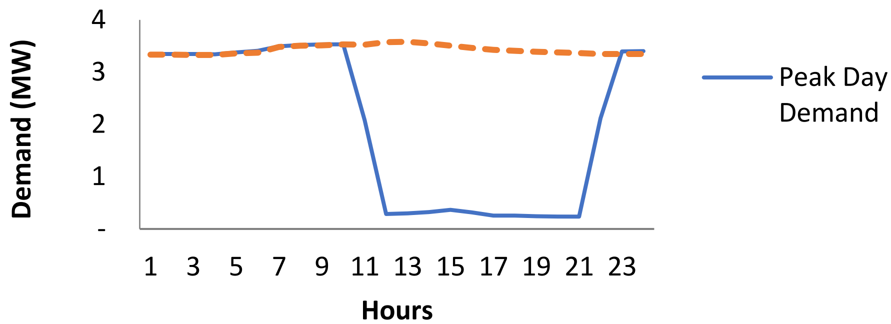


Figure 1. Sample LDR Event with a 3 MW Customer

For the 2020-2024 period, Toronto Hydro expanded the program to target two stations, Manby TS , and Horner TS. The details of this program are outlined in section E.7.2.2.4 below.

<u>Evolution of LDR: Flexibility Services</u>

For the next rate period, Toronto Hydro will build on the success of LDR to build a Flexibility Services program, which will expand to include services other than standard 4-hour DR. As with LDR, Flexibility Services are demand-side services that the utility purchases from customers and third-party vendors (i.e. energy services providers and aggregators) in order to address distribution system needs. These services allow the utility to work with customers and vendors to change where or when electricity is consumed, helping to level out peaks in demand. The goal is to find innovative ways to support electrification while enabling efficient use of capital, avoiding overbuilding the distribution system.

Table 2. Types of Flexibility Services:

Type of Service	Description	Use Case
Demand Response (DR)	Contractual arrangements with customers or aggregators for 4-hour blocks of load curtailment	Peak-shaving, capacity support
Short-Duration DR	Contractual arrangements with customers for 2-hour blocks of load curtailment. Enables participation from a wider variety of loads	Peak-shaving, capacity support

A key feature of the Flexibility Services program is the development of a competitive marketplace for the procurement of resources. To create this successfully, Toronto Hydro will:

- Identify areas in the system where demand-side approaches can help alleviate system constraints;
- Determine characteristics of capacity requirement (i.e. quantity, duration, seasonal need, expected number of activations);
- Conduct an options analysis to determine how these system needs can be addressed conventionally, and utilize this analysis to determine the capacity value and target price for capacity; and
- Communicate this information to prospective participants via an online platform; and
- Hold periodic auctions to procure capacity competitively, allowing Toronto Hydro to match available capacity with system needs.

One result of Toronto Hydro's 2020-2024 LDR program will be the creation of an online DR Capacity Auction tool, which enables the competitive procurement of DR capacity. This tool can be utilized in the 2025-2029 period to target several station areas (see Drivers section for more details). A prototype of the tool is currently under development in partnership with Toronto Metropolitan University's Centre for Urban Energy ("CUE").

E7.2.1.2 Outcomes and Measures

The Flexibility Services program works together with the Stations Expansion and Load Demand programs to ensure Toronto Hydro can supply growing customer demand while maintaining system reliability and improving grid resiliency. By leveraging customer-owned energy resources to offset peak demand, Flexibility Services provides incremental customer value in the form of grid optimization capabilities that were not traditionally available to grid planners and operators, while also providing an incremental source of value to current and prospective DER owners. This aligns with Toronto Hydro's broader modernization strategy, which aims to implement technologies and develop capabilities that will allow the utility to optimize the utilization and performance of its grid, ensuring distribution service and access remains as cost-effective as it can be while keeping up with anticipated demand pressures from electrification and the digitalization of the economy.

Table 3: Outcomes & Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: o Engaging with customers and enabling them to participate in the grid o Adding flexibility to the grid to enable efficient customer connections o Providing revenue opportunities for DERs, thereby encouraging DER uptake and integration
Operational Effectiveness - Reliability	• Contributes to maintaining Toronto Hydro's system reliability objectives by providing additional tools for managing and prioritizing capacity constraints.
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by acting as a bridging strategy to help to avoid (or defer) capital investments where demand is uncertain.
Public Policy Responsiveness	• Contribute to Toronto Hydro's public policy responsiveness objectives by: o Responding to the regulator's direction for utilities to consider and leverage NWSs where possible to drive rate-payer value o Reducing greenhouse gas (GHG) emissions by enabling the proliferation of energy storage, DERs, and grid-modernization o Enabling electrification by investing in additional capacity and operational flexibility

E7.2.1.3 Drivers and Need

Table 4: Segment Drivers – Flexibility Services

Trigger Driver	Capacity
Secondary Driver(s)	Reliability

The Flexibility Services program primarily helps complement conventional station expansion and load demand programs to address capacity constraints on the distribution system. Pressures such as densification, population growth, and electrification create constraints that need to be addressed either by building additional capacity, transferring load, or reducing load on the system via demand-side services.

These conditions are expected to intensify beyond 2024 as supported by the City of Toronto's long-term Precinct Plans[1] for both the downtown and the Horseshoe areas and by Toronto Hydro's 10-Year Station Load forecast (see Section D4 of the DSP). The Station Expansion program speaks extensively to the identified needs in Toronto Hydro's service territory over the 2025-2029 period.[2]

While the Station Expansion program at Toronto Hydro addresses large-scale, longer term load growth challenges through the provision of new or expanded transformer stations, the Load Demand program ensures that sufficient capacity is always available to keep pace with day-to-day load growth, preventing the overloading of system assets.

As described in the Load Demand program, a key tool for meeting capacity needs and ensuring system reliability and efficiency is bus level load transfers (load transfers between station buses to alleviate overloaded buses).[3] The Flexibility Services program directly supports Load Demand by identifying opportunities to defer or avoid these load transfers when and where it is appropriate.

To help identify where to target Flexibility Services, both long-term planning (station expansion) and short-term planning (load demand) needs are considered to identify opportunities for NWS support. Factors that are considered when selecting a target area include high-levels of projected growth, large customer connections (e.g. data centres), high levels of load connections generally, and projections for electrification drivers, e.g. electric vehicle adoption. For the 2025-2029 period, the Flexibility Services program will focus on one major station cluster in Toronto Hydro's service territory: Horseshoe North.

It should be noted that a key feature of the Flexibility Services program is that it can easily adapt in terms of scope and location to meet the most pressing system needs. The current focus on Horseshoe North is due to the high potential for NWSs to defer capital expenditure. This is based on the identified system needs, as well as an assessment of current and expected future DER capacity. This station cluster has emerged as an ideal target area because:

- High levels of load growth are expected over the next ten years;
- Large-scale developments (including City Downsview Development) are expected to materialize in the near-term;

[1] City of Toronto, *How Does the City Grow?* https://web.toronto.ca/wp-content/uploads/2017/08/9014-How-Does-the-City-Grow-April-2017.pdf
[2] Exhibit 2B, Section E7.4.
[3] Exhibit 2B, Section E5.3.

- Currently has a high-penetration of large Key Account customers, some of which have DER capacity that could be utilized to provide distribution grid services; and,
- It has been identified as an area that will require up to 130 MVA of load-transfers in the next rate-period.

Based on Toronto Hydro's most recent 10-year station load forecast,[4] three Horseshoe North West stations will require capacity relief in the 2024-2029 period: Fairbank TS, Finch TS, and Bathurst TS.[5] Details about the load projections in this area are outlined in the Station Expansion section and the Load Demand section.[6]

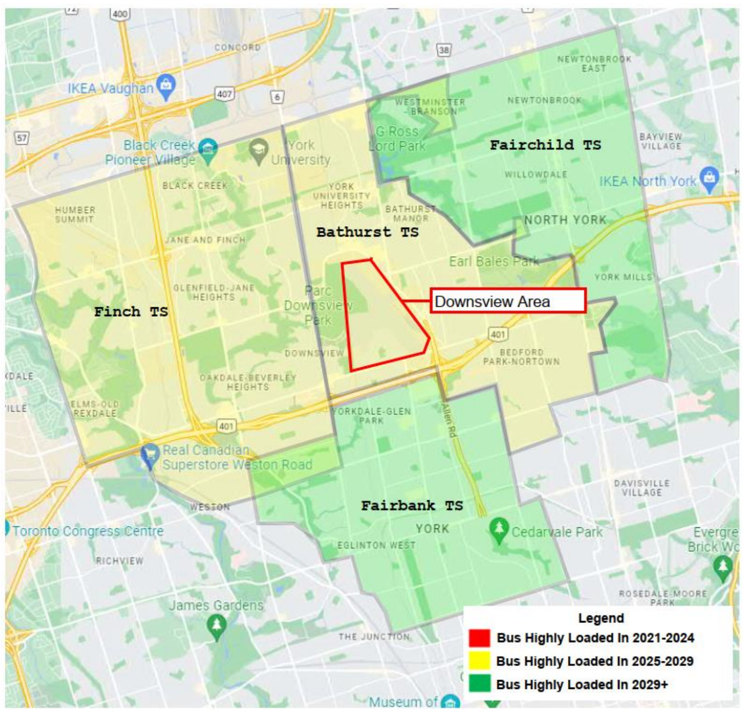


Figure 2: Service Territories of Stations in the Downsview Area

[4] Described in Exhibit 2B, Section D2.3 System Utilization
[5] Typically, load relief on a 27.6 kV horseshoe station bus is required when the forecasted peak load of the bus reaches 95 percent of the bus firm capacity.
[6] Exhibit 2B, Section E5.3.

Table 5: Non-Coincident Downsview Area 10-Yr Load Forecast[7]

STATION	Summer LTR (MW)	2021 Actual	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bathurst TS	361	67%	71%	70%	75%	80%	85%	90%	94%	99%	98%	97%
Fairbank TS	182	108%	102%	92%	90%	90%	91%	90%	91%	91%	92%	93%
Fairchild TS	346	62%	68%	72%	72%	72%	72%	71%	71%	71%	71%	71%
Finch TS	366	69%	75%	88%	97%	97%	98%	98%	98%	99%	100%	100%
Area Non-Coincident %	**1255**	**72%**	**76%**	**79%**	**83%**	**84%**	**86%**	**87%**	**88%**	**90%**	**90%**	**90%**

The current shortage of feeder positions or bus capacity makes it difficult to connect new customers to an optimal supply point within the station service area. In this case, feeders are extended outside the boundary of the station service area, which may require the construction of additional civil infrastructure. Furthermore, load transfers between feeders could also be required to accommodate new customer connection from the nearest available feeder.

Table 6. Load Transfers Anticipated in 2025-2029 Period

Station	Bus	Estimated Load to Transfer (MVA)	Area
Bathurst	*J&Q*	5 – 20	Horseshoe North
Fairbank	*B & Q*	15 – 30	Horseshoe North
Finch	*B&Y, J&Q*	25 - 55	Horseshoe North

Flexibility Services targeting these stations can provide temporary relief, giving planners flexibility to determine whether load transfers will become necessary. As part of the Load Demand program, station bus load forecasts are re-evaluated annually and informed by up-to-date system conditions,

[7] Hydro One Needs Assessment Report, Toronto Region (December,2022)

new connections, and updated weather corrected load forecasts. Based on the outcome of this evaluation, the need for specific load transfers can either be escalated in priority or deferred. This provides Toronto Hydro with the opportunity to explicitly consider and use NWSs to help avoid a portion of these load transfers when possible[8]. This consideration will inform where to focus NWS procurement efforts on an annual basis utilizing the appropriate, competitive process. This has been an auction process in the 2020-2024 period; however, as part of the ongoing evolution of this program, Toronto Hydro will continue to consult with stakeholders to refine and update the procurement mechanism, ensuring maximum participation from customers and aggregators.

Given the range of expected load transfers in Table 6, Toronto Hydro will aim to procure up to 30 MW of demand response capacity in the Horseshoe North area. This could help avoid anywhere between 28 percent to 66 percent of the total load required to be transferred in this area. This translates to avoided capital expenditure in the range of $10 million, at a projected cost of about $5.7 million in operating expenditure. Further details about costs are provided in the Expenditure plan.

E7.2.1.4 Expenditure Plan

Table 7 and Table 8 below summarize the LDR Program plan for 2020-2024.

Table 7: 2020-2024 CIR – LDR ($ Millions)

	2020	2021	2022	2023	2024	Total
CAPEX	1.0	-	-	-	-	1.0
OPEX	-	0.8	0.8	0.8	0.8	3.2

Table 8: Actual and Bridge Costs- LDR ($ Millions)

	Actual			Bridge	
	2020	2021	2022	2023	2024
CAPEX	1.0	-	-	-	-
OPEX	0.2	0.2	0.2	0.7	0.7

[8] As noted in the Load Demand narrative (Exhibit 2B, Section E5.3.), Manby TS and Horner TS, which were originally planned for relief in the 2020-2024 period, have been deferred to the 2025 period, in part due to the Local Demand Response program.

For the 2020-2024 period, Toronto Hydro has moved the majority of the capital allocated to the LDR battery system into the ESS program to plan and track all ESS projects under one program. The remainder of the total 2020-2024 Local DR program cost (e.g. incentives, labour) is not capitalized (i.e. OPEX). The majority of the costs are related to DR capacity payments ($1.4 million), and the remainder of the costs ($0.6 million) are related to program administration, legal costs, and consulting costs. Details about costs are provided in the program description below.

1. 2020-2024 Local Demand Response Program

For the 2022-2024 period, Toronto Hydro has continued to advanced capabilities in the NWS space, building on the work done in the 2015-2019 period at Cecil TS. For this period, the LDR program targeted two transformer stations (TS): Manby TS and Horner TS. These stations were selected based on specific needs; Manby TS has been reaching capacity on two busses for several years and overloading at Horner TS has been forecasted in the near-to-mid term. These capacity issues were identified in Toronto Hydro's 2015-19 Custom IR Application[9] and Hydro One's 2016 Regional Infrastructure Plan for the Metro Toronto Region.[10]

Several load transfers north to the Richview TS have been completed. Further transfers are difficult due to the distance between the stations and a lack of remaining overhead corridors running north-south. Load transfers to neighbouring stations to the east cannot be easily achieved due to capacity constraints at Runnymede TS, the Humber River posing a geographical barrier, and different system voltages (13.8 kV vs 27.6 kV). Load transfers to the west and south are not possible because the Manby TS and Horner TS are on the boundary of Toronto Hydro's service territory. Due to limited space at Manby TS for expansion, work has been underway to expand capacity at Horner TS. This new capacity will be utilized to relieve Manby TS in 2025. In the meantime, while the expansion work is undertaken, LDR has been leveraged to provide increased flexibility in the Manby TS and Horner TS area. As a result, some additional load transfers from Manby and Horner TS have been avoided over this rate-period and it is expected that this will continue to be the case until 2025, when load will be permanently removed from Manby TS to Horner TS.[11]

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[9] Toronto Hydro Custom IR Application for 2015-2019 (OEB File No. EB-2014-0116).
https://www.rds.oeb.ca/CMWebDrawer/Record?q=CaseNumber=EB-2014-0116&sortBy=recRegisteredOn-&pageSize=400
[10] https://www.hydroone.com/about/corporate-information/regional-plans/metro-toronto
[11] Exhibit 2B, Section E5.3

As noted, the majority of the LDR program costs are related to capacity payments for demand response ($1.4 million), and the remainder of the costs ($0.6 million) are related to program administration.

The capacity payments made to DR providers are benchmarked against the cost of additional load transfers that would have otherwise been required at Manby TS and Horner TS. It was estimated that the capital cost of executing 10 MW of load transfers from Manby TS or Horner TS to adjacent stations would be in the range of $4 million. Utilizing LDR to avoid these load transfers between 2023-2025 has effectively helped manage demand in this area until the expansion of Horner TS is complete and a permanent transfer can be made from Manby TS in 2025. As such, it was important to ensure that the total cost of LDR (capacity payments + admin) was well below the cost of the wires solution on a net present value basis. The maximum capacity payment for LDR was benchmarked utilizing a discounted cash flow model comparing the cost of load transfers to the cost of LDR, and the capacity payment was further driven down as a result of competitive procurements. The LDR program was initially projected to cost $4 million but will cost closer to $2 million over the current rate-period.

Evolution of LDR: Grid Innovation Fund Pilot Project

In late 2021, Toronto Hydro identified an opportunity to build on the LDR program planned for Manby TS and Horner TS to examine how Toronto Hydro and other distributors can work with the Independent Electricity System Operator (IESO) to better coordinate the use of DERs as NWSs in order to maximize value and lower resource acquisition costs. The IESO's regional planning documents indicated that capacity constraints were expected in the Richview-Manby transmission corridor starting in 2021. Transmission system upgrades will be necessary to address these capacity constraints. Due to project lead-time, the upgrades are not expected to come into service until 2025. The IESO is pursuing short-term measures, such as incremental Conservation and Demand-side Management (CDM) and DR, where feasible and cost-effective, to assist in reducing customer reliability risk until the transmission system upgrade can come into service.

Given the clear alignment of needs between Toronto Hydro and the IESO, Toronto Hydro partnered with Power Advisory LLC and Toronto Metropolitan University's CUE, to create a project that explores how to effectively and efficiently procure and deploy DR capacity to address overlapping distribution and transmission system level needs. This project is called the Benefit Stacking

Transmission and Distribution Pilot ("Benefit Stacking Pilot") and is supported by the IESO's Grid Innovation Fund, and the Ontario Energy Board's (OEB's) Innovation Sandbox.

Currently, customers with load control capabilities or behind-the-meter DERs seeking to provide DR services interact with Toronto Hydro's distribution system (e.g., LDR) and the IESO-operated transmission/bulk system (e.g. as Market Participant) separately. There is limited opportunity for coordination between the two systems to maximize the benefit and value of the DERs.

The Benefit Stacking Pilot Project explores how customer-owned DERs can provide services to both the distribution grid and transmission/bulk system using an efficient single pathway that works with existing market mechanisms. By making it easier for DER owners to participate in multiple programs thereby maximizing the value proposition for DERs to provide non-wires services, it is anticipated that participation levels would increase which would then, over time, drive down resource procurement costs. A key deliverable of the Benefit Stacking Pilot Project will be an analysis of the resulting rate-payer value of the dual DER participation.

Toronto Hydro will simulate offering LDR capacity into the IESO market, unlocking additional revenue streams and system benefits, often referred to as "benefit stacking". Toronto Hydro will also simulate the utilization of the LDR resources in the IESO's real-time markets, testing how Transmission-Distribution system coordination can be undertaken to avoid conflicting dispatch instructions between the two levels. The costs of the simulation are being funded through the IESO's Grid Innovation Fun (GIF). The pilot explores current barriers to LDC-IESO coordination, seeks to improve overall visibility for both LDCs and the IESO with respect to DR resource activities and identify pathways for better coordination, leading to more efficient dispatch at both levels.

2. 2025-2029 Forecast Expenditures

Given the range of expected load transfers in Table 6, Toronto Hydro will aim to procure up to 30 MW of demand response capacity in the Horseshoe North area. This could help avoid anywhere between 23 percent to 54 percent of the total load required to be transferred in this area. This translates to an avoided (or deferred) capital expenditure in the range of $10 million (at minimum), at a projected cost of about $5.7 million in operating expenditure.

Because Flexibility Services are market-based, the goal will be to again run competitive procurements that enable Toronto Hydro to drive down the cost of contracting for DR. The anticipated spend of $5.7 million dollars is based on the current market value of demand response in the LDR program, which is $700/MW-day for the summer 2023 period. However, each time a procurement is planned, Toronto Hydro will go to market to determine if the NWS is cost-effective as compared to the wires solution. To determine the cost-effectiveness, the cost of the specific load transfers would be compared to the procurement of DR over a specified period of time. This analysis determines the reference price for the DR, and the competitive procurement seeks to further lower this price through competition.

Table 9. Segment Unit Scenarios over 2025-2029 period

Segment	Cost per unit	Target Capacity	Projected cost	Capital Avoidance & Deferral
Flexibility services	$0.7M/MW	Up to 30 MW	$5.7M	$10M

Table 10: 2025-2029 CIR – Flexibility Services ($ Millions)

	2025	2026	2027	2028	2029	Total
Flexibility Services (OPEX)	0.2	0.9	1.1	1.6	1.9	5.7

It is anticipated that Toronto Hydro will spend the first year of the 2025-2029 rate period prioritizing targeted stations, setting capacity targets, and developing procurement processes and documentation. Between 2026-2029, Toronto Hydro will set the following procurement targets:

- 2026: 10 MW
- 2027: 15 MW
- 2028: 25 MW
- 2029: 30 MW

Program operating costs are based on an assumed capacity payment of $700/MW-day plus $200,000 per year for labour and operations. It is highly likely that the $700/MW-day figure will be driven down through competitive procurements over time, which means the total program cost for Flexibility Services should be understood as a maximum cost that could be significantly lower. The 2020-2024 total program cost, for example, will come in at almost half of what was anticipated due to procurement efficiencies.

E7.2.1.5 Options Analysis

Option 1: Conventional Wires Options

As noted, the wires option for addressing short to medium term constraints in the Horseshoe North cluster of stations would include bus level load transfers. The range of expected load transfers are indicated in Table 6 above. Proceeding with Option 1 would mean failing to consider the role of NWSs when scoping and prioritizing those bus-level load transfers, losing the opportunity to defer or avoid anywhere between 23 percent to 54 percent of the total load required to be transferred in this area. Financially, this translates to a potential deferral or avoidance of up to $10 million in capital in the Load Demand program.

Additionally, proceeding without a Flexibility Services program would present a lost opportunity to build a more intelligent and interactive grid that can leverage local sources of generation and capacity resources to optimize grid performance. Doing nothing in the NWS space also presents a missed opportunity to work with customers and third-parties such as aggregators to find innovative solutions to distribution system problems. Customer engagement results indicate that it is important to customers to find ways to engage with the utility to better manage electricity usage, as well as to find efficiencies and cost reductions. The Flexibility Services program is directly responsive to this priority. Ultimately, the goal is to find the lowest-cost solution by exploring all possible options, including demand-side measures.

As demand becomes increasingly unpredictable due to increased uptake of DERs, Flexibility Services can help the utility navigate this uncertainty by providing a greater number of cost-effective options. This strategy checks an important regulatory requirement to evaluate alternatives to building traditional poles and wires infrastructure. It also enables a new lens on productivity – one that is focused on managing total system cost by optimizing how capital is allocated to address system needs more efficiently. In the Conservation and Demand-Side Management Guidelines, the OEB directs all utilities to explore NWSs alongside conventional wires solutions to provide cost-effective system options. Not proceeding with the Flexibility Services program would impact Toronto Hydro's ability to explicitly consider LDR options when addressing system issues.

Option 2: Continue with a small-scale LDR program that targets 1-2 stations

This option entails continuing with the LDR program as it is currently run in the 2020-2024 period, which means focusing on a modest capacity procurement of 10 MW and selecting 1-2 stations within the Horseshoe North cluster to target. This option would help defer a small number of load transfers in this area, and would come in at a lowered cost of about $3.6 million (about $2 million less than the proposed plan in Option 3). There are several drawbacks to this approach. While it does cost less, it also provides a reduced opportunity for load transfer deferral (about $4 million versus the $10 million in the proposed option). Furthermore, in the current LDR program, the feedback from aggregators has been that smaller target areas make it very challenging and costly to acquire enough capacity to make participation in LDR economical from their perspective. Targeting 1-2 stations can mean a relatively small pool of possible participants, leading to more difficult procurement processes. From a program administration perspective, it does not cost significantly more to procurement 30 MW versus 10 MW, making a larger-scale program more cost-effective overall. Looking at the number of DERs connected in the Horseshoe North area, targeted a greater number of stations results in a larger opportunity to contract for flexibility services.

Option 3 (Selected Option): Create a Flexibility Services Program that Targets Horseshoe North Station Cluster

Option 3, which is the recommended option, is to build a Flexibility Services program that works in tandem with the Load Demand program to address short-to-medium term load constraints in the Horseshoe North region of Toronto Hydro's service territory. This program will enable the explicit consideration of NWSs when evaluating and prioritizing bus level load transfers to address load growth and capacity issues in this area.

Because Flexibility Services are market-based, they also provide a crucial opportunity for utilities to leverage relationships with customers and third-parties to solve grid problems. Utilities have a great deal of system knowledge, data, engineering and operational experience; private sector organizations have developed excellent tools to help customers manage load behind the meter. Through working together, new and innovative ideas and solutions are generated that can help the sector better prepare for challenges ahead.

E7.2.1.6 Execution Risks and Mitigation

Procurement of Flexibility Services requires careful consideration of several factors. Over the last 8 years of running LDR, Toronto Hydro has navigated many challenges and come away with important lessons learned for how to manage risks.

Risk: Low participation levels in procurements

Going to market to procure flexibility services may not always yield successful results. This can be related to lack of resources, misaligned incentives, customer/participant confusion, or poor timing. To help mitigate these risks the following measures can be taken:

- Targeting station areas with a large penetration of large customers and existing DERs;
- Ensuring customers and aggregators are educated about programs through early participant engagement via program materials, webinars and one-on-one conversations;
- Creating programs that are straight-forward, with simple participation pathways and performance charges that create the right incentives without being too punitive; and,
- Ensuring aggregators have sufficient time to recruit customers.

Risk: Price discovery

One of the biggest challenges in the procurement of NWSs is price discovery. It is a given that the reference price for an NWS must be benchmarked against the cost of the wires alternative. However, the benchmark price may not always reflect the market price (i.e. the price the market participant is willing to take for their services). This process of price discovery presents many opportunities for learning and adapting in order to find the right balance of incentives. This includes not only the capacity or energy payment, but also any performance charges that may apply to ensure the services are reliably delivered. Some of the risks involved could include:

- Overpaying for services
- Setting prices too low resulting in low uptake
- Creating performance charges that are too lenient, resulting in poor performance
- Creating performance charges that are too stringent, resulting in poor uptake

To help manage these risks, it is important to learn from other jurisdictions, work with stakeholders in advance to understand their costs, and remain nimble and adaptable by doing shorter term procurements while working to understand the market. The experience gained in the 2020-2024 period has been instrumental in learning what works and what does not work in terms of price discovery. These learnings will be taken into the next rate period.

E7.2.2 Energy Storage Systems (ESS)

E7.2.2.1 Background

Energy Storage Systems give utilities the flexibility to store energy and use it at a later time. As demand for system flexibility increases and battery technology costs decrease, ESS are expected to play a growing role in generation, transmission and distribution system planning. Utilities can utilize ESS in a variety of ways to support the grid. Toronto Hydro has been active in the energy storage space since 2017, with several existing projects, including behind-the-meter ("BTM") and front-of-the-meter ("FTM") installations outlined in Table 11 below.

Table 11. Existing Toronto Hydro ESS Projects

<table>
<tr><th>Project</th><th>Description/Use Case</th><th>Nameplate Capacity</th><th>Learnings</th></tr>
<tr><td>Bulwer BESS</td><td>FTM BESS supporting Cecil TS via peak-shaving</td><td>2MW/ 2MWh</td><td>○ BESS deployment and optimization utilizing Toronto Hydro's Energy Centre (DERMS) platform
○ Trouble-shooting operational challenges (e.g. faults)
○ Experience with creating baselines and measuring peak-shaving success on feeder</td></tr>
<tr><td>500 Commissioners</td><td>BTM BESS located at Toronto Hydro's facility, used for peak-shaving and GHG reductions</td><td>500kW/ 500kWh</td><td>○ Optimizing use of BESS to lower facility electricity costs and target GHG reductions via peak-shaving
○ Experience with maintaining BESS</td></tr>
<tr><td>TTC eBus</td><td>Customer-specific project providing charging support and peak-shaving</td><td>1MW/ 4MWh x 3</td><td rowspan="2">○ Understanding of connection requirements from other stakeholders, such as HONI and IESO, for large size BESS deployments
○ Optimizing BESS operation for EV charging use case
○ Understanding of design and commissioning requirements of features such as black start and dynamic transfer which are needed for islanding scenarios</td></tr>
<tr><td>Metrolinx Eglinton Crosstown LRT</td><td>Customer-specific project used for emergency back-up and load displacement</td><td>10MW/ 30 MWh</td></tr>
</table>

Toronto Hydro has learned a great deal with respect to procuring, designing, constructing, commissioning, and utilizing BESS over the last six years. The Bulwer project, which is the only FTM

BESS that is entirely owned and operated by Toronto Hydro, has been instrumental for developing knowledge around utilizing BESS to provide distribution-level grid support. This project was built in the 2015-2019 rate period and energized in January 2020. Over the 2020-2023 period, this project has been tested, commissioned, and transitioned to operations for deployment. This project helped Toronto Hydro develop:

- New processes for monitoring and controlling BESS assets on a daily basis,
- IT frameworks for integrating BESS software platforms safely and seamlessly with existing Toronto Hydro IT infrastructure,
- Methodologies for determining charging schedules, managing BESS state of charge, and measuring peak-shaving at the feeder level, and
- Maintenance of BESS assets.

Toronto Hydro also has experience with BTM BESS projects, including one at the 500 Commissioners street facility, and two that are located on customer sites (Metrolinx ECLRT and TTC eBus). These projects have also enabled building significant capabilities building, integrating and deployment of BESS. Based on current system needs, Toronto Hydro does not expect to own and install any BTM or customer-specific BESS projects in the next rate-period.[12]

2025-2029 ESS Vision

Toronto Hydro will build on its experience with BESS to move from individual pilot projects towards a standardized approach for design and deployment. The planned deployments will target areas with grid constraints to enable Renewable Energy Generation (REG) connections.

The BESS program has matured significantly as a result of the last six years of experience. Due to the new and innovative nature of this program area, the work achieved up until this point has been primarily pilot driven. Toronto Hydro has tried various approaches for procuring and siting BESS. One of the main challenges has been finding locations to install projects in areas where the grid has specific needs that could be addressed by BESS. Given the urban and dense nature of Toronto Hydro's service territory, land comes at a premium, and the use of this land must be assessed carefully to

[12] See for example: OEB Staff Bulletin, August 6, 2020 re Ownership and operation of behind-the-meter energy storage assets for remediating reliability of service. https://www.oeb.ca/sites/default/files/OEB-Staff-Bulletin-ownership-of-BTM-storage-20200806.pdf

ensure asset siting decisions are prudent and cost-effective. Another challenge has been to integrate different types of BESS projects, each with unique software platforms and maintenance needs.

The strategy for the next rate period will explore a standardized approach for siting, designing and procuring BESS, utilizing small scale installations that enable siting on the right-of-way, similar to other distribution system equipment (e.g. pad-mounted transformers). This, in addition to standard BESS deployments, will help Toronto Hydro build a more scalable and streamlined BESS program in the future.

Based on current, identified distribution system needs that will be examined below, as well as Toronto Hydro's commitment to support the electrification and anticipated growth of renewable generation in the city, the BESS portfolio will focus primarily on the renewable enablement use case in the 2025-2029 rate period. Several studies have shown that significant penetration of renewable generation can lead to destabilizing grid parameters.[13] In the renewable enablement use case, ESS can act as a load to prevent output curtailment from the renewable assets while ensuring a stable grid through controlling the minimum load to generation ratio (MLGR).

Based on internal studies, Renewable Enabling ESS can be installed anywhere along a feeder in order to help mitigate concerns regarding generation to minimum load ratio. Therefore, to avoid additional costs, the proposed ESS units could potentially be connected to existing Toronto Hydro assets (i.e. pad mounted transformers) that can accommodate the nameplate capacity, footprint and layout. If such assets and locations cannot be established, then new assets (i.e. transformer) will be installed to accommodate the proposed ESS.

Toronto Hydro is also actively working to optimize the deployment of BESS projects by leveraging its corporate-academic partnership with the Toronto Metropolitan University CUE. With this partnership, Toronto Hydro and CUE are developing an Optimal Planning Program which optimizes sizing and the return on investment of an ESS for both BTM and FTM applications. This tool will be an essential method in which Toronto Hydro evaluates and deploys BESS projects in the future for applications such as load displacement, deferred system expansion and premium reliability service. Quantifying net benefits for each of these scenarios will allow Toronto Hydro to design storage systems that can maximize the value proposition to the customer and the utility.

[13] Seguin, R., Woyak, J., Costyk, D., Hambrick, J., & Mather, B. (2016). (tech.). High-Penetration PV Integration Handbook for Distribution Engineers (pp. 4–26). Oak Ridge, Tennessee: Office of Scientific and Technical Information.

Another part of the BESS strategy is to improve asset integration so that newly deployed systems can co-exist with Toronto Hydro's IT framework. This will involve continuing to integrate all existing storage platforms within the Distribution Grid Operations Energy Centre DERMS platform.

E7.2.2.2 Outcomes and Measures

Table 12: Outcomes & Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer service objectives by enabling customer investments in renewable energy and reducing energy costs.
Operational Effectiveness - Reliability	• Contributes to service reliability by utilizing BESS technology to improve load-balancing on feeders that have been identified to have issues with respect to MLGR.
Financial Performance	• Contributes to Toronto Hydro's financial objectives and performance by cost-effectively enabling renewable generation where applicable.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy objectives by enabling the proliferation of energy storage, renewable DERs, and grid-modernization.

E7.2.2.3 Drivers and Need

Table 13: Segment Driver

Trigger Drivers	Capacity
Secondary Driver	Reliability, Public Policy

Renewable Enabling BESS

Policy, economic conditions and the preferences of customers and consumers, have facilitated a growing interest in DERs within Toronto Hydro's service territory. This trend is expected to continue into the foreseeable future supported by a number of drivers that are stemming from global, national and local levels such as the Federal Government's green energy tax credit and the recent Regulatory policy changes. In 2022, the Ontario Energy Board enacted changes that enabled third-party ownership of Net Metered generation facilities. Toronto Hydro anticipates that third-party installations will play a key role in driving renewable energy generation ("REG") growth during the next rate period as it did in other provinces and the US where this arrangement is already well established. In addition, the anticipated decreasing costs of photovoltaic panels is expected to have a positive impact on customer interest in REG. These drivers will increase interest in distributed renewable generation projects within Toronto Hydro's service territory by 2029, as shown below on Figure 3. Please refer to the Generation Connections narrative for more details on the drivers behind the anticipated REG growth in the next rate period.

An increase in renewable generation projects will lead to a fundamental change in the power flow conditions at the distribution system and how they need to be managed. This has challenged the conventional radial nature of the grid to accommodate bi-directional power flow. Large scale deployment of REG is known to cause issues in distribution system planning and operations such as unintentional islanding and overvoltage on feeders. As a result, Toronto Hydro must proactively relieve certain grid constraints on feeders in order to accommodate future REG growth.

As part of its DER connection process, Toronto Hydro offers a pre-application report for its customers, providing information about the proposed point of interconnection so the customer can determine if a DER system installation is worth pursuing. The pre-application process also allows Toronto Hydro to discover potential distribution system issues that must be addressed to accommodate the proposed DER. In such instances, Toronto Hydro would work with the customer to find the best solution to move the DER installation forward, such as modifying the proposed system to satisfy the pre-application screening. Although Toronto Hydro has been able to manage DER customer expectations to date through this pre-application process, certain parts of the distribution system are approaching their technical limits and the problem could worsen over the next few years. Renewable Enabling ESS investments can help Toronto Hydro alleviate these issues to accommodate future REG growth, while maintaining adherence to the Transmission Interconnection Requirements.

As can be seen in the Figure 3 below, there has been a consistent increase in the number of renewable generation connections to the distribution grid. The data observed assumes a negligible uptake of wind or other inverter-based DER technologies and therefore uses the solar PV forecast as the primary REG type driving increased penetration. These assumptions are based on historical consumer behaviour in REG adoption in the City of Toronto and are consistent with forecasting models used in the Generation Connections segment.

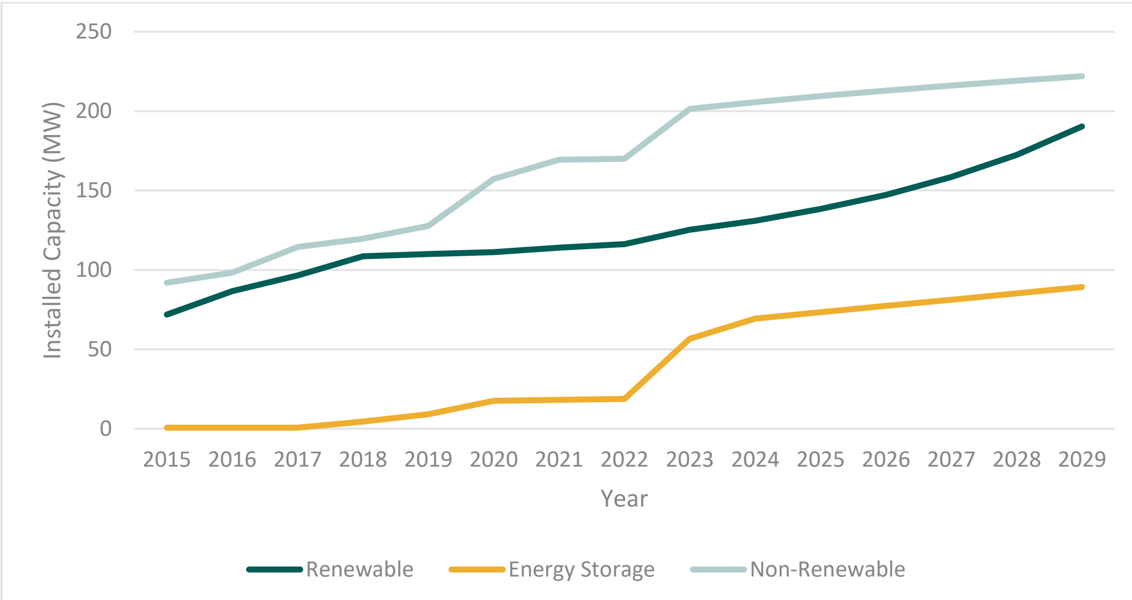

Figure 3: Historical and Forecasted Renewable Generation (MW)

Table 14: Forecast Generation Capacity (in MW)

Generation Type	2023	2024	2025	2026	2027	2028	2029
Renewable	126.4	133.4	143.4	155.1	168.5	183.6	200.4
Energy Storage	56.6	60.0	73.4	77.4	81.4	85.4	89.5
Non- Renewable	198.2	212.1	215.6	218.7	221.6	224.3	226.8
Total	**381.2**	**405.5**	**432.4**	**451.2**	**471.5**	**493.3**	**516.7**

High penetration of renewable energy generation sources can lead to grid instability if not managed appropriately. Two modes of grid instability can be seen: unintentional islanding and system overvoltage. While these issues can not be resolved easily using conventional utility approaches, ESS solutions present an ideal alternative given their ability to dynamically charge and discharge to balance feeder loading. The following sections will outline the two modes of grid instability and expand on how ESS can help alleviate the issues.

Unintentional Islanding

In the past few years, there have been numerous studies, standards and guidelines with respect to DER integration, such as IEEE Standard P1547.2/D6.5, August 2023 (Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces)[14] and National Renewable Energy Laboratory's High Penetration PV Integration Handbook for Distribution Engineers (NREL Handbook). These documents prescribe limitations on DER aggregate capacity to be less than one-third of the minimum load of the Local Electric Power System.[15] As the ratio of generation capacity to minimum load increases, the amount of time required by inverters to respond to anti-islanding scenarios increases and this can adversely impact the effective inverter response to anti-islanding scenarios. This scenario can be mitigated with the addition of transfer trip protection, which is only a requirement for DER connections over 1MW; however, this is a costly measure. Furthermore, for feeders that have a high penetration of small to medium DER connections, it would not be economically feasible for each customer to install transfer trip as the cost is too high relative to the cost of the connection. Since most of the REG connections that get connected to Toronto Hydro's grid are small to medium size connections, renewable enabling ESS becomes an attractive option as it can serve to mitigate this risk for any customer along the feeder as opposed to being an individual customer solution.

Toronto Hydro conducted an analysis for all feeders in its system to establish minimum load to generation ratios[16] in accordance with the applicable guidance found in IEEE-P1547.2/D6.5, August 2023. The methodology consisted of aggregating the DER generation capacity at the feeder level. For this particular study only the DERs that were connected and in-service were used, and DERs that were proposed were only factored into the forecasted values. The next step involved using load profiles to determine the minimum load on each feeder in the past three years and computing the MLGR. This process was repeated for all feeders that had aggregate DER capacity above 500 kW. The list was further refined by calculating the REG penetration ratio on each feeder which helps identify feeders that would best be served by a renewable enabling ESS solution.

The DER forecast shown in Figure 3 above is a system level forecast that is consistent with the GPMC and Customer Connections narratives. This system level forecast was applied to the feeder level

[14] "IEEE Draft Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," in IEEE P1547.2/D6.5, August 2023 , vol., no., pp.1-322, (11 Aug. 2023).
[15] Ibid.
[16] Determined as available utility fault current divided by DG fault contribution in affected area.

forecast in Table 15 below to determine the DER forecast for each of the shortlisted feeders as well as the forecasted impact on MLGR.

The study found that 23 feeders currently exceed the 3:1 minimum load to generation screening ratio outlined by the NREL Handbook and is shown in Table 15 below. Assuming there are no short circuit capacity constraints at the transformer station and given the forecasted growth in REG only by 2029, an additional 24 feeders would exceed the generation to minimum load ratio.

Table 15: MLGR feeder analysis

Station	Feeder Name	Nameplate Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Minimum Load (MW)	Current MLGR	MLGR Forecast 2029	REG Connections enabled (MW)
Agincourt TS	63-M6	3.530	100.0%	5.77	7.10	2.011	1.230	2.24
Finch TS	55-M31	1.750	100.0%	2.95	3.52	2.011	1.193	1.20
Fairbank TS	35-M8	1.997	83.0%	2.80	5.50	2.753	1.750	1.15
Rexdale TS	R29-M1	1.115	100.0%	1.94	2.54	2.275	1.305	0.83
Horner TS	R30-M3	0.760	100.0%	1.38	1.91	2.519	1.387	0.62
Scarborough TS	E5-M24	3.712	16.5%	1.15	4.12	1.109	0.969	0.53
Horner TS	R30-M10	4.573	12.5%	1.08	5.12	1.120	1.007	0.51
Bathurst TS	85-M6	6.761	7.5%	0.98	5.56	0.822	0.768	0.47
Bathurst TS	85-M30	5.250	9.5%	0.97	2.83	0.539	0.495	0.47
Finch TS	55-M32	1.508	33.2%	0.97	4.09	2.712	2.069	0.47
Leslie TS	51-M25	1.677	25.5%	0.85	4.88	2.911	2.322	0.43
Finch TS	55-M29	1.914	21.7%	0.83	4.22	2.205	1.809	0.42
Fairchild TS	80-M10	1.300	23.1%	0.65	2.69	2.069	1.629	0.35
Leslie TS	51-M23	2.100	14.3%	0.65	4.58	2.181	1.868	0.35
Bathurst TS	85-M7	6.105	1.7%	0.34	2.62	0.429	0.413	0.24
Bathurst TS	85-M1	6.013	0.2%	0.20	6.86	1.141	1.107	0.18
Finch TS	55-M2	5.300	0.0%	0.18	2.96	0.558	0.541	0.18
Bathurst TS	85-M32	4.750	0.0%	0.18	6.08	1.280	1.234	0.18
Windsor TS	A-61-WR	1.500	0.0%	0.18	2.75	1.835	1.642	0.18
Esplanade TS	A-39-X	7.000	0.0%	0.18	14.50	2.072	2.021	0.18
George Duke TS	A-45-GD	1.050	0.0%	0.18	2.18	2.074	1.776	0.18
Fairchild TS	80-M23	0.900	0.0%	0.18	2.12	2.356	1.970	0.18
Cecil TS	A-41-CE	1.275	0.0%	0.18	3.37	2.646	2.326	0.18

Renewable Enabling ESS can be deployed on such feeders in order to increase the minimum load to generation ratio to the recommended threshold. The technology has the capability to do so by functioning like a load when the minimum load is low. Conversely, when the minimum load is appropriately above the threshold, the ESS can act like a generator by supplying energy. This can provide FTM load displacement as well as other target area specific benefits.

In short, the screening ratios show that by 2029 all 47 feeders will have a high penetration of PV generation and require grid investments or other solutions to ensure the safety of the grid and allow further REG connections. ESS is recognized as an effective distribution system solution to increase the PV connection capacity.[17]

The direct benefit of installing renewable enabling ESS can be quantified by the amount of REG capacity that is enabled through these investments which is shown on the far-right column in Table 15 above. This also forms the basis for prioritizing which feeders should be resolved as they provide the largest benefits as a renewable enabling investment. Otherwise, a lack of these renewable enabling ESS investments would result in a forecasted amount of 30MW of REG by 2029 to be potentially rejected for connection.

Toronto Hydro also envisions renewable enabling ESS investments that are driven by large customers installing large renewable DERs. Such a large and sharp increase of renewable DER penetration could disturb the grid stability and the generation to load ratio. Renewable enabling ESS solutions would be installed on the relevant feeders to support the grid, smooth the ratio and allow for the increase of renewable generation on the grid.

System Overvoltage

ESS deployments can also mitigate the grid risk of experiencing overvoltage on some of Toronto Hydro's feeders. Load demand and PV generation have different impacts on a feeder's voltage profile. As load demand increases, operating voltage dips, while as PV generations increases, the voltage spikes. Based on internal studies, there is an increased overvoltage risk for equipment on feeders with low load demand and a high PV penetration. Results have shown that utilizing a BESS to balance the load on such feeders could mitigate that risk and consequently enable further renewable connections on the grid.

[17] For example, see:
(i) J. Seuss, M. J. Reno, et al, "Improving distribution network PV hosting capacity via smart inverter reactive power support", Proc. IEEE PES General Meeting, July 2015, pp. 1–5.
(ii) Z. Waclawek, et al, "Sizing of photovoltaic power and storage system for optimized hosting capacity", Proc. IEEE International Conference on Environment and Electrical Engineering, June 2016, pp. 1–5.
(iii) B. P. Bhattarai, et al, "Overvoltage mitigation using coordinated control of demand response and grid-tied photovoltaics", Proc. IEEE SusTech, Jul 2015.
(iv) F. Capitanescu, et al, "Assessing the potential of network reconfiguration to improve distributed generation hosting capacity in active distribution systems", IEEE Transactions on Power Systems, Jan 2015, vol. 30, no. 1, pp. 346–356.
(v) Y. Takenobu, et al, "Maximizing hosting capacity of distributed generation by network reconfiguration in distribution system", Proc. Power Systems Computation Conference (PSCC), June 2016, pp. 1–7.

E7.2.2.4 Expenditure Plan

1. 2020-2024 CIR Energy Storage Systems ("ESS") Program

Table 16: 2020-2024 CIR – ESS Program ($ Millions)

	2020	2021	2022	2023	2024	Total
GPESS	-	2.7	2.8	-	-	5.5
REBESS	1.0	1.0	1.0	1.0	1.0	5.0

Table 17: Actual and Bridge Costs – ESS Investments ($ Millions)

	Actual			Bridge	
	2020	2021	2022	2023	2024
BESS[18]	-	0.5	0.1	0.3	0.3

Toronto Hydro planned to install aggregate capacity of 8MW/4MWh of Grid Performance ESS over the 2020-2024 period, at a total cost $5.5 million. The plan was for the project to be implemented in 2021 and 2022. Toronto Hydro also proposed in the last rate application to install three Renewable Enabling ESS units with an aggregate capacity of 2.35MW/9.5MWh, at a total cost of $5 million.

Toronto Hydro faced numerous challenges in completing the proposed projects and was unable to proceed as planned. After exploring additional opportunities to deploy ESS, Toronto Hydro is proceeding with one renewable enabling ESS unit in the current rate period. This process has provided valuable information and experience that has informed the development of Toronto Hydro's ESS plan going forward. Toronto Hydro is revising its approach for this program in the 2025-2029 period, focusing on creating a more scalable, demand-driven ESS program that utilizes small-scale ESS technologies.

Toronto Hydro faced three significant challenges in deploying ESS in the 2020-2024 rate period:

i) Siting projects;
ii) Supply chain constraints; and
iii) Integration of one-off procurements into Toronto Hydro's IT and other systems.

[18] BESS amounts reflect combined investments for GPESS and REBESS.

Building on the lessons learned from navigating these challenges, Toronto Hydro has identified an opportunity to deploy an ESS unit to target a feeder that exceeds the MLGR threshold.

Challenges Deploying ESS

Siting ESS Projects

Finding a site has been the one of the biggest roadblocks for installing ESS in Toronto. It is often difficult to line-up a site in an area where ESS can provide cost-effective grid services. This challenge is uniquely difficult for Toronto Hydro as its service area is dense and urban. So far, Toronto Hydro has installed one front-of-the-meter ESS (Bulwer) at a decommissioned Municipal Station site.

Supply Chain Constraints

During the current rate period, COVID-19 led to significant supply chain issues resulting in major delays throughout the entire ESS sector. Certain types of equipment, such as Static Transfer Switches (STSs) had lead times of up to 2 years. Many of the after effects of these supply chain issues continue to impact project execution, specifically with respect to shortages in lithium production for Lithium Ion ESSs. Supply chain risks have diminished since the height of COVD-19 and are not expected to be material over the next rate period.

Integration of One-off Procurements

Another challenge relates to the integration of ESS into existing frameworks and systems. This is exacerbated by one-off procurements with several different vendors. For example, it has been a challenge to integrate various types of custom BESS systems that utilize different software platforms for system charging and management from an IT perspective. Toronto Hydro's IT systems have strict requirements with respect to data access, hardware and security. It is also necessary to create maintenance plans for the ongoing management of these assets, which can be made complicated when there are various types of custom system installed. To that end, Toronto Hydro is currently working on standardizing the process of ESS design and procurement through the development of technical requirements that will be used in future RFPs.

Grid Performance ESS (GPESS) Project

As part of the 2020-2024 period, Toronto Hydro explored the possibility of installing a 5 MW ESS to mitigate voltage sags on feeder 51-M30, which is fed by Leslie TS. This project was intended to pilot the use of an ESS to resolve voltage sag issues for large commercial customers located on the targeted feeder. This feeder was selected based on analysis evaluating the following criteria:

- Number of customers impacted:
  - More than one key account customer connected on the feeder
- Land for ESS installation:
  - Feeder must be in proximity to existing decommissioned Municipal Stations (MS) that can be utilized for ESS site
- High number of sags:
  - ION meter data for key account customers on select feeders exhibited high number of sags recorded for the 2018 to mid 2021 period
  - The number of interactions regarding voltage sag concerns between the customer and the Key Account team at Toronto Hydro were also considered a factor

Table 18: Targeted Feeder for GPESS Deployment

Candidate Feeder	Decommissioned MS Nearby?	# of Key Customers	2021 Recorded Sag Event	Recommended GPESS Size
51-M30	Yes (Lesmill MS)	2	Key Customer #1 - 32 Key Customer #2 - 29	5.2MW/1.3MWh

In 2020, Toronto Hydro hired Quasar to perform a study about the technical feasibility of an energy storage system that eliminates short duration voltage fluctuations on a feeder. The final report provided a high-level cost estimate for the feasible options, identified completed projects in which the solutions have been implemented and developed a list of vendors that offer the required equipment to implement suggested solutions.

In 2021, Toronto Hydro worked with GE to determine the feasibility of integrating a power conditioning system within the distribution system. The aim of the study was to identify the main possible topologies, determine load case scenarios, simulate the performance of the best selected topology and develop a preliminary sizing of required components.

In 2022, Toronto Hydro developed and ran a Request-for-Proposals ("RFP") process to procure an ESS capable of providing voltage support on the identified feeder, as well as peak-shaving support, and the ability to island for the purpose of outage mitigation. This RFP was put out to market twice:

once in July 2022 and once in September 2022. Both processes resulted in no appropriate bids from vendors.

To understand the lack of response from vendors, Toronto Hydro conducted feedback sessions and learned that many BESS developers were focusing on larger-scale deployments (greater than 10 MW) that enabled ownership retention and power purchase agreements with the IESO (via medium and long-term contracts). Other vendors noted that the technical requirements of Toronto Hydro's RFP were complex and necessitated more in-depth preliminary engineering analysis to accurately define the requirements. With these lessons learned, Toronto Hydro is working with external consultants to undertake engineering studies assessing the technical feasibility of a BESS that addresses feeder-level voltage sags, while also determining the compatibility of this use case with others (e.g. peak-shaving, load-balancing, black-start). The goal is to be better equipped to scope BESS projects that enable benefit stacking, maximizing the cost-effectiveness of these projects.

Renewable Enablement ESS Project

Despite the previously-described difficulty in finding a viable site for REBESS, Toronto Hydro aims to target one small deployment within this rate period. The deployment being targeted this rate period will be on one of the 23 feeders which are above the MLGR threshold as highlighted in Table 15 above. The feeder selected for the deployment will hinge on the various constraints such as location, sizing and budget. The prudent approach would be to target a singular small deployment in an area that is relatively easy to deploy, gather learning lessons and carry those lessons into the planned deployments for the next rate period.

In addition to this, Toronto Hydro is working with internal stakeholders and vendors to explore innovative methods of deployment such as smaller scale BESS units along the right of way in order to alleviate the need to find large land areas as well as available decommissioned Municipal Stations that can be repurposed to site BESS.

2025- 2029 Forecast Expenditures

Table 19: 2025-2029 CIR – BESS ($ Millions)

	2025	2026	2027	2028	2029	Total
BESS	3.6	3.6	7.5	3.8	4	22.5

Table 20: 2025-2029 CIR – BESS (Systems)

	2025	2026	2027	2028	2029	Total
BESS	1	2	2	2	2	9

Toronto Hydro plans to deploy nine projects in the BESS program with an aggregate capacity of 10.2 MW to mitigate the forecasted impact of PV penetration and enable further renewable growth on the grid. The 10.2 MW of BESS capacity is what is needed to bring up the MLGR ratio on the 9 high-priority feeders outlined in Table 15, to the required MLGR threshold. The planned deployments are estimated to cost $22.5 million with an assumption of $446/kWh This works out to $1.78M/MW for a four hours system and results in an expenditure cost of $18.19 million. A 10 percent buffer was added for potential cost overruns resulting in a $20 million total expenditure cost. The derived $/MW is based on industry benchmark[19] as well as Toronto Hydro's renewable enabling ESS technology evaluation. Toronto Hydro plans to distribute the planned numbers of projects evenly over the next rate period to optimize utilization of current staff and take advantage of one project's lessons learned onto the next one.

Renewable enabling BESS investments are distribution investments that support the growth of distributed renewable generation on the system, that in turn offset generation and transmission investments to the benefit of all Ontario rate payers, and that also create environmental benefits. As with other renewable enabling improvements, renewable enabling BESS are funded six percent in Toronto Hydro's rate base and 94 percent through the provincial renewable enabling improvement revenue stream. Over the 2025-2029 period, $22.5 million is proposed for this segment, $1.6 million (six percent) allocated to Toronto Hydro's rate base as the assets are in-service. These investments are expected to enable the aggregate connection of 10.2 MW of REG by 2029, which wold otherwise not be possible due to the technical limitations of the grid.

[19] Viswanathan, Vilayanur, et al. "Energy Storage Cost and Performance Database." *Pacific Northwest National Laboratory*, 1 Aug. 2022, www.pnnl.gov/lithium-ion-battery-lfp-and-nmc.

Table 21: Priority REBESS Deployments

Station	Feeder Name	Existing DER Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Minimum Load (MW)	Current MLGR	MLGR Forecast (2029)	REG connections enabled by 2029 (MW)	Req. BESS Size (MW)
Agincourt TS	63-M6	3.53	100.0%	5.77	7.10	2.011	1.230	2.24	3.49
Finch TS	55-M31	1.75	100.0%	2.95	3.52	2.011	1.193	1.20	1.73
Fairbank TS	35-M8	2.00	83.0%	2.80	5.50	2.753	1.750	1.15	0.49
Rexdale TS	R29-M1	1.12	100.0%	1.94	2.54	2.275	1.305	0.83	0.81
Horner TS	R30-M3	0.76	100.0%	1.38	1.91	2.519	1.387	0.62	0.37
Finch TS	55-M32	1.51	33.2%	0.97	4.09	2.712	2.069	0.47	0.43
Leslie TS	51-M25	1.68	25.5%	0.85	4.88	2.911	2.322	0.43	0.15
Finch TS	55-M29	1.91	21.7%	0.84	4.22	2.205	1.809	0.42	1.52
Fairchild TS	80-M10	1.30	23.1%	0.65	2.69	2.069	1.629	0.35	1.21
Total				**16.57**				**6.12**	**10.2**

E7.2.2.5 Options Analysis

1. Option 1: Do Nothing

Twenty-three feeders in Toronto Hydro's territory currently exceed the acceptable generation to minimum load ratios and an additional 24 feeders are forecasted to exceed acceptable ratios by 2029. If no action is taken, it is possible that forecast demand for DG, including REG, would not be safely accommodated in those areas. This could potentially put forecasted REG connections with an aggregate capacity of 29.78MW at risk of getting rejected by 2029. This would be an undesirable outcome for customers, the City of Toronto, and Toronto Hydro and would hinder Toronto Hydro's ability to meet its obligation to connect renewable generation (i.e. pursuant to Section 6.2.4 of the Distribution System Code). This will also restrain the efforts being made to accelerate the uptake of renewables and meet net zero targets in Toronto. Customers who are willing to invest in modernizing the grid will likely become frustrated, and the associated grid and upstream benefits will not be realized. Finally, this will be in non-compliance with the results of Toronto Hydro's customer engagement process, which stressed on the importance of allocating expenditures to modernize the grid and support renewable growth.

2. Option 2: Traditional "poles and wires" solutions

While Toronto Hydro has the Generation Protection Monitoring & Control (GPMC) program to address system-wide issues to enable DER, issues involving generation to minimum load ratio, feeder phase imbalances and bus voltage imbalances will still persist and could potentially inhibit the connection of new renewable DER projects. GPMC will give Toronto Hydro the required control to disconnect DERs in case of an unintended islanding situation. However, the issues explained in section E7.2.2.4 cannot be addressed with the GPMC initiatives.

Feeder re-configurations and reverse load transfers could be performed to increase load on forecasted feeders where generation to minimum load ratios are high. However, this method may decrease reliability and may not always be feasible due to the existing network configuration. Furthermore, these are static solutions not well-suited to managing the dynamic nature of balancing load to generation, meaning these options would not resolve the issue the way a BESS would.

Another traditional option to mitigate the risk of unintentional islanding is with the addition of transfer trip protection; however, this is only a requirement for DER connections over 1MW and is a costly measure. Since most of the REG connections that get connected to Toronto Hydro's grid are small to medium size connections, it would not be feasible for customers to install transfer trip as the cost is too high relative to the cost of the connection.

3. Option 3: Production Curtailment and Decreasing Operational Margin

With better resource monitoring, and forecasting and real-time estimation of the grid capacity, applicable operational margins can be reduced. This in turns allows the existing infrastructure to be used more efficiently and to a greater extent (i.e. with a higher capacity factor). For more detailed information regarding this option, please refer to the Generation Protection, Monitoring, and Control Program.[20]

Curtailment occurs when plants are required to reduce their generation output in order to maintain the operational limits of the grid. This may entail a small gradual decrease of the production (referred to as soft curtailment) or a complete stop to production through measures such as inter-tripping (referred to as hard curtailment). Soft curtailment requires a communication infrastructure and methods to assess the real-time performance of the grid and the appropriate production decrease.

[20] Exhibit 2B, Section E5.5.

In a deregulated market without vertically integrated utilities, it requires willingness from grid users to participate and a legal framework enabling such participation. Moreover, economic arrangements are required to allocate the loss of income stemming from curtailed production.

It is also important to note that for renewable enablement, curtailment is not an option as REG is either connected or not. While curtailment is not viewed as a viable option at the moment, Toronto Hydro is assessing the feasibility of having flexible DER connections on its system, which could work to mitigate load-to-generation imbalances for further DERs. More information about this program is outlined in the Grid Modernization Roadmap narrative.

4. Option 4 (Selected Option): Proposed Solution

The proposed Renewable Enabling BESS program will provide Toronto Hydro with strategic capabilities to address specific issues relating to REG enablement in targeted areas of its distribution system. It will allow Toronto Hydro to mitigate the problems described in Section 7.2.2.4 and fulfill its regulatory obligations to connect REG projects pursuant to the DSC. The proposed solution also best positions Toronto Hydro to support the goals of the Climate Action Plan with respect to enabling renewable generation and deploying energy storage. It is expected that these investments will enable the aggregate connection of 10.2 MW of REG by 2029 which would otherwise be constrained. The overall cost of this option is an estimated $20 million over the 2025 to 2029 period.

E7.2.3 Execution Risks and Mitigation

Project execution risks may impact project design, project siting, approvals, construction, project schedule and commissioning. Compared to traditional technologies, there are fewer technical resources in the sector with knowledge on ESS that are available to design, install and commission the systems, which can lead to a delay in program implementation and increased costs. Toronto Hydro will manage this risk by researching and applying relevant experiences from other jurisdictions and investing in training and staff development for engineering and skilled trades.

ESS projects are complex due to bi-directional power flow and interface protections between project locations and their associated feeder or station supply point. Commissioning risk can be mitigated by using a standard requirements matrix and site acceptance testing protocol. Further, in-depth training in advance of actual field work is planned for crew members and operations staff who will take part in ESS installation and commissioning.

Toronto Hydro will manage risks regarding integrating BESS with our current IT network through consciously working with the IT team to understand their technical requirements and considerations. This will help establish a standardized IT framework for the BESS program that we can incorporate in our upcoming project RFPs.

As outlined in earlier sections of this document, Toronto Hydro anticipates project siting to be one of the critical risks for this program in the next rate period. In order to manage this risk in the short term, Toronto Hydro is working with its Stations and Facilities teams to explore any available opportunity to repurpose existing Toronto Hydro facilities such as decommissioned Municipal Stations. At the same time, the end goal is to establish a more standardized and reliable approach for project siting. Toronto Hydro's vision is to create a strategy that leans on modular and small-scale BESS to enable BESS deployments on city boulevards, similar to other traditional Toronto Hydro assets.

Project schedule risk can be effectively managed by dedicated project teams that provide short-interval control and regular coordination between the utility and customers. Toronto Hydro will dedicate its efforts to ensure labour availability and manage project prioritization with other capital project and planned maintenance work will be managed to implement this program on-schedule.

Construction cost variance is mitigated through a competitive procurement system for ESS projects and standard contract provisions which provide fixed price responsibility and liquidated damages for non-performance. Based on the 2022 Grid Energy Storage Technology Cost and Performance Assessment by Pacific Northwest National Laboratory,[21] battery ESS technology will mature and prices will fall, providing some protection against year-over-year inflation and a degree of budget contingency. Battery costs represent approximately half the cost of ESS, while inverters, switchgear, transformation, controls, conditioning, civil work and enclosures make up the balance. Further, the report determined that current installed costs for Lithium Ion (LFP) BESS is $446/kWh and this is expected to decrease to $340/kWh by 2030. As such, over the 2025-2029 period, the cost/benefit value proposition of ESS will likely continue to improve, thereby facilitating increased use of this solution to address customer needs.

[21] Viswanathan, Vilayanur, et al. "2022 Grid Energy Storage Cost and Performance Assessment." *Pacific Northwest National Laboratory*, Aug. 2022.

E7.3 Network Condition Monitoring and Control

E7.3.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 56.8	**2025-2029 Cost ($M)**: 6.0
Segments: Network Condition Monitoring and Control	
Trigger Driver: Reliability	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Environment, Operational Effectiveness - Safety, Financial Performance	

The Network Condition Monitoring and Control ("NCMC") program (the "Program") is introducing real-time, Supervisory Control and Data Acquisition ("SCADA")-enabled monitoring and control capabilities to Toronto Hydro's low voltage secondary network distribution system. The network system supplies 10-15 percent of the peak load in downtown Toronto, including customers like banks and hospitals who are highly sensitive to service interruptions. SCADA-enabled monitoring and control will benefit these customers, and the public who relies on these customers, by introducing remote monitoring and switching capabilities that are already utilized in many other parts of the system. It will also introduce real-time monitoring capabilities with respect to the following types of operating parameters:

- Air temperature and water level in the vault;
- Oil level, top-oil temperature and tank pressure of the network transformer;
- Current, voltage, open/closed status and presence of water level in the network protector, which is essential to the automatic transfer capabilities that allow the maximum reliability benefits of the network design to materialize; and
- Other sensors such as fire and analog water sensors for early detection of fire events and flooding.

These capabilities will enable improvement in key outcomes for downtown customers, the public, and the environment, including: remote identification of active failure risks (e.g. floods) and prevention of subsequent outages; the ability to sustain service for substantially more customers during multiple contingency events; early identification of potential safety risks (e.g. vault fires); early identification of oil leaks; and improved loading data accuracy, which will help Toronto Hydro provide greater and more efficient access to the network system for connecting customers. Finally, these capabilities will enable a reduction in yearly inspection activities, leading to maintenance cost savings once most of the network vaults are commissioned.

Toronto Hydro's progress in this program in 2020-2023 is a recent example of its grid modernization track record. For more information on how the NCMC program supports the Intelligent Grid component of the utility's Grid Modernization Roadmap, please refer to Exhibit 2B, Section D5.

The low voltage network distribution system has historically been Toronto Hydro's most reliable system. Over the last several years Toronto Hydro began deploying new, higher voltage network units to better accommodate new customer requirements in the downtown area and help reverse a gradual decline in the number of customers connected to the network. At the same time, the condition of the existing network is worsening as vaults experience floods and transformers corrode and leak oil, as evidenced by the many deficiencies observed in recent years. Catastrophic and highly disruptive failures affecting customers have also occurred in recent years. Given these constraints and pressures, Toronto Hydro is prioritizing the program as a means of improving reliability, system resiliency, and efficiency of operations on the network.

Toronto Hydro is investing $56.8 million in the 2020-2024 rate period and $6 million in the 2025-2029 rate period to install monitoring equipment and fibre optic cable in approximately 920 network vaults. Once this initial deployment is complete, Toronto Hydro plans to invest $1.8 million between 2026 and 2029 on a pilot project to further enhance real-time monitoring capabilities by installing additional sensors in the network vault. This will support the outcomes summarized above and described in more detail below.

1 ## E7.3.2 Outcomes and Measures

2 **Table 2: Outcomes and Measures Summary**

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives (e.g. OEB's ESQR targets, which require new services to be connected on time 90 percent of the time) by enabling more efficient connections through use of live loading data for power flow modeling.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives by: ○ Reducing flooding-related equipment damage; ○ Enabling the early detection of conditions that can cause vault fires to improve response time and mitigate damage; ○ Providing real-time loading data and remote switching capabilities to allow controllers to drop approximately one-third fewer customers from the network during multiple contingency events. • Contributes to network grid resilience by: ○ Identifying flooding so that measures can be taken to prevent equipment damage.
Environment	• Contributes to Toronto Hydro's environmental objectives by reducing oil leaks through monitoring of transformer oil levels.
Operational Effectiveness - Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency measure and safety objectives by enabling early warning of potential risks associated with vault loading, flooding and fire. • Remote monitoring will reduce time crews spend in the confined space of a vault to determine loading and protector status.
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by reducing the need for crews to perform inspections needed to obtain summer load readings.

E7.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Reliability
Secondary Driver(s)	Safety, Failure Risk, System Efficiency, Resiliency

As summarized in Toronto Hydro's Grid Modernization Roadmap, the NCMC program is an important part of Toronto Hydro's Grid Modernization Roadmap and a recent example of its modernization track record. The NCMC program is successfully introducing the capabilities and benefits of an Intelligent Grid to Toronto Hydro's network system, including enhanced observability (i.e. real-time or near real-time data on grid performance and conditions) and incremental controllability. Together, these capabilities are providing a foundation for the realization of substantial reliability, resiliency and efficiency benefits.[1]

The Program aims to improve the reliability of Toronto Hydro's low voltage secondary network system by introducing real-time SCADA-enabled monitoring and control. The installed equipment and fibre optic communication cables provide live condition, loading data and remote-control capabilities in approximately 920 vaults that will enable Toronto Hydro to respond proactively and more effectively to emerging hazards and multiple-contingency events, leading to fewer and shorter interruptions for sensitive downtown customers. The planned number of vaults represents approximately 90 percent of the network vaults in the system. Toronto Hydro is not planning to target the remaining 10 percent due to the following factors:

- The equipment in the vault is manual and not automation ready, such as using manual secondary switches instead of network protectors; and
- The location of the vault requires high civil costs due to its remote location and lack of spare ducts required for fibre.

As the Program matures, Toronto Hydro is piloting other options to connect vaults without the need for fibre, such as using a long-term evolution ("LTE") communication device. Toronto Hydro is piloting this solution in a few vaults using customized Vault Communication Boxes ("VCBs"). If successful, this

[1] Exhibit 2B, Section D5

could allow Toronto Hydro to bring NCMC functionality and capabilities to vaults that would otherwise be cost-prohibitive.

Figure 1 depicts the components required to enable monitoring and control of a network vault and unit. Vault sensors – which include a water level sensor and a vault temperature sensor – are connected directly to the VCB. Transformer mounted sensors include oil temperature, oil level and tank pressure. Protector monitoring and control are all enabled through a special communication-ready network protector relay mounted inside the network protector.[2] Based on the age and make of the network units, some need to be retrofitted as they do not have the required sensors built-in (oil temperature, oil level and tank pressure). These retrofit packages will allow for NCMC capabilities to be available at the vault.

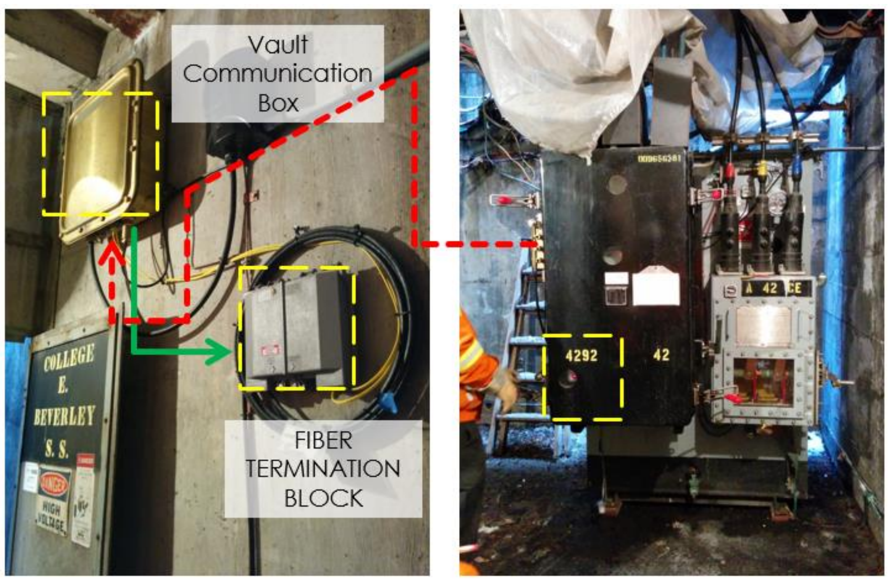

Figure 1: Vault Layout with Network Condition Monitoring and Control Equipment Installed

Once the VCB is installed, connected and commissioned inside the vault, Toronto Hydro can monitor and control the automated vaults through a SCADA screen from the control room, an example of which is shown in Figure 2 below.

[3] The network protector automatically connects and disconnects individual transformers from the secondary grid to compensate for primary feeder switching and equipment failures.

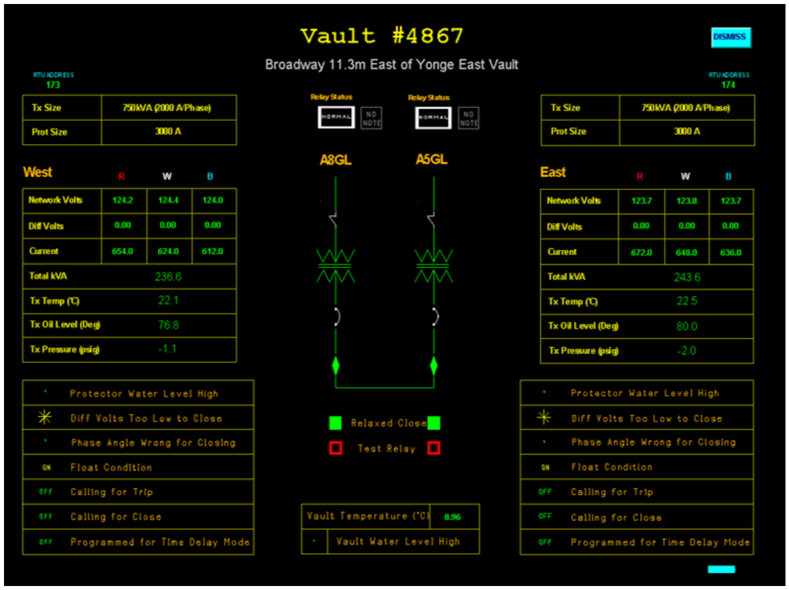

Figure 2: SCADA Screen for a Vault with Network Condition Monitoring and Control

E7.3.3.1 Benefits of Network Condition Monitoring

The Program will provide real-time condition data of the vault and network units. This will give the Control Room access to important information on developing hazardous conditions such as flooding, fire, and oil leaks, allowing proactive measures to be taken to prevent equipment failure and mitigate safety and environmental risks. Such data includes vault temperature and water level, network transformer operating temperature, oil level and tank pressure, and the presence of water inside network protectors. When real-time condition data is not available through NCMC, it is acquired through estimates or field inspections, which are both less accurate and more resource intensive.

The use of water level sensors can mitigate the risk of equipment damage and reduce customer service interruptions due to vault flooding. Once installed, water level sensors trigger alarms in the Control Room as rising water reaches the sensor. Toronto Hydro can then dispatch a crew to address the flooding prior to water levels reaching a point where equipment is damaged or at risk of failure. In the past two years, water alarms were raised at 56 network vaults which helped prevent flooding in the vault from occurring.

Monitoring of the network vault temperature will also enable Toronto Hydro to detect fires earlier, improving response time and mitigating any damage to equipment and safety risks that may result. If a fire occurs, the Control Room will be informed and can remotely operate vault equipment to prevent catastrophic failures. This would help lessen the impact to the customers directly connected to a given vault, as well as minimize potential widespread network outages that impact all customers connected to the network grid. In the past two years, temperature alarms from 14 unique vaults were triggered, allowing for pre-emptive response to potentially catastrophic failures.

Oil leaks are another concern which can be addressed through network monitoring. If a serious transformer oil leak is not promptly identified, the transformer is likely to fail once the oil level drops below the windings or upper cooling tubes. This could result in a catastrophic transformer fire causing widespread and prolonged customer interruptions and safety risks. In addition, early oil leak identification can minimize environmental damage. Leaking oil within a vault may enter the vault drainage system and discharge into the environment. Oil level monitoring data will also support the accurate reporting of oil quantities to the Ministry of the Environment and Climate Change and the City of Toronto should a spill occur.

This Program has already contributed to reducing the number of oil leaks and, more specifically, high-volume leaks as seen in Figure 3. In 2021 and 2022, SCADA event logs indicate there were 34 incident alarms of low oil level at 16 vaults which enabled early detection of oil leaks, limiting the volume of those leaks.

The majority of the oil leaks from 2020 onwards were within the 0-10 litre volume range. This timeframe aligns with the start of network vault commissioning with NCMC. A specific example of NCMC mitigating oil leaks occurred in June 2022, when a NCMC commissioned unit was leaking approximately 500 ml of oil per day. Once the alarm occurred, the controller trigged a crew to verify and open the primary switch to isolate the defective unit. The unit was subsequently reactively replaced. As Toronto Hydro continues to commission more vaults, the Control Room will be able to respond much earlier to any potential oil spill across the network system to minimize the number of spills as well as their volume.

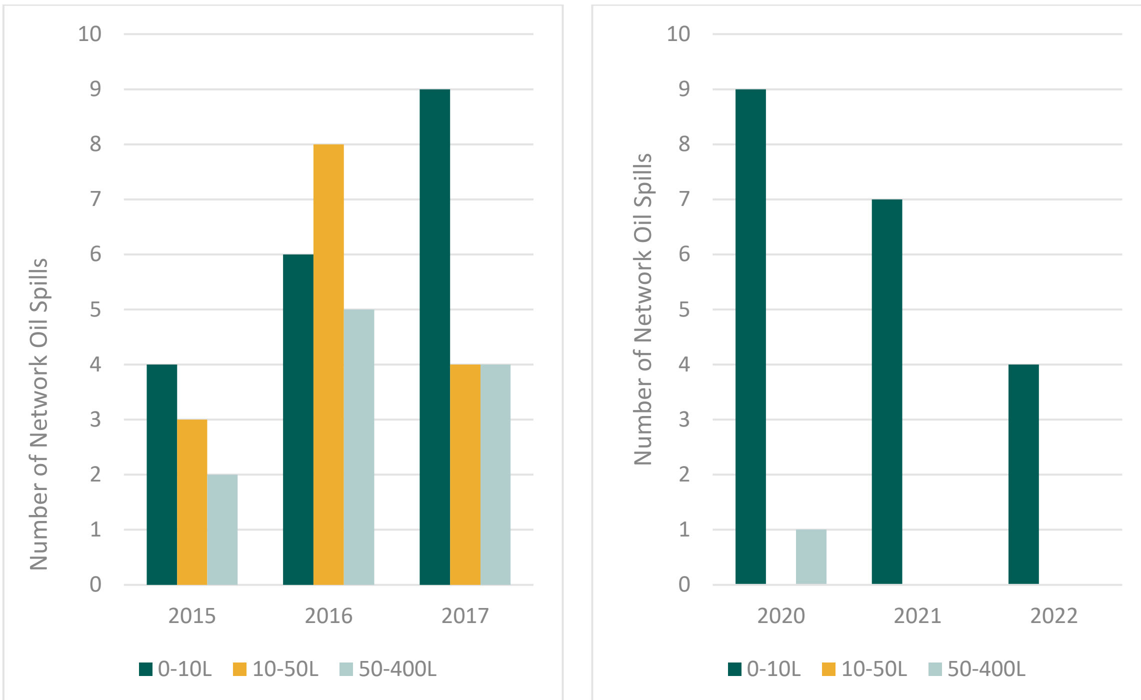

Figure 3: Network Transformer Oil Spills before NCMC (left) and after (right) NCMC

This Program will reduce the need for field staff to patrol networks, identify and investigate deficiencies such as protectors, flooded vaults (after heavy rainfall) and faulted network transformers. This results in estimated cost savings of $200 per hour per incident.[3] In the last five months of 2022, Toronto Hydro saved approximately $78,600 in operating costs by remotely checking protectors in commissioned vaults rather than sending trucks and crews. Toronto Hydro expects these benefits to scale as it continues to commission vaults.

Toronto Hydro has realized benefits from the condition monitoring achieved in the network vaults commissioned to date. As of the end of 2022, 379 vaults have been commissioned, which amounts to approximately one-third of all network vaults. As the Program continues to mature and more vaults are commissioned, Toronto Hydro is planning to continue to calibrate alarms and improve business processes in order to maximize the benefits of the Program.

[3] This is the cost of sending a crew to investigate an incident in a network vault.

E7.3.3.2 Benefits of Network Unit Control and Loading Data

Monitoring and control equipment also provides remote control capabilities and loading data required for emergency operations as well as normal analysis and planning. Real-time loading data allow controllers to more effectively respond to multiple-contingency events and emergency situations, resulting in fewer and shorter customer interruptions. Remote monitoring and control can also reduce the need for crews to visit vaults during switching events. For example, as of June 2023, Toronto Hydro has saved approximately $119,850 through the reduced need to deploy crews to vaults during switching events. This benefits customers by both expediting service restoration during network emergencies, as well as reducing costs associated with normal network system operations. Features that will provide these benefits include:

- Monitoring of operating voltages and currents;
- Monitoring of the open/closed status of network protectors;
- Ability to remotely open or close protectors;
- Automatic reporting of conditions preventing equipment from automatically operating as desired (e.g. voltage too low to reclose); and
- Ability to temporarily alter equipment settings to facilitate automatic operation (e.g. “relaxed close”) that would otherwise not occur.

The loads for the low voltage secondary networks targeted for this program in 2020-2025 are shown in Table 4 below. Through this program, Toronto Hydro expects to avoid dropping one third of the total network load (which would otherwise have to be dropped in multiple contingency events). These networks are designed to handle first contingency (N-1) outages at both the feeder and network unit levels without causing customer interruptions. However, second contingency (N-2) or higher events require network analysis to determine whether customer loads can be sustained or must be dropped in order to avoid excessive equipment loading levels. In the absence of live loading data, conservative load estimates are made for this analysis. Toronto Hydro derives these estimates using loading data from summer inspections, which may not be accurate due to variances in season, ambient temperature, time of day, and day of the week. In contrast, accurate real-time loading information will allow the Control Room to operate network equipment according to the actual limits during multiple contingency events.

Table 4: Potential Customer Load Saved from Network Monitoring and Control[4]

Network	Total Load on Feeders (MVA)	Network Load (MVA)	Commissioning Year	Expected Load Saved During Multiple Contingency Events (MVA)
Cecil-North Phase 1	32	6.5	2019	4.3
Cecil-South Phase 1		6.5	2020	
Windsor-West Phase 1	55	12.5	2020	8.3
Windsor-West Phase 2		12.5	2021	
Terauley-North Phase 1	44	13.5	2021	9
Terauley-North Phase 2		13.5	2021	
George and Duke Phase 1	49	11.6	2021	9.7
George and Duke Phase 2		17.4	2021	
Charles-West Phase 1	45	11	2022	7.3
Charles-West Phase 2		11	2022	
Bridgman Total	29.2	14.6	2023	4.9
High-level Total	112	56	2023	18.7
Glengrove Total	28	14	2024	4.7
Duplex Total	69.6	34.8	2024	11.6
Gerrard Total	12	6	2024	2.0
Dufferin Phase 1	21.2	4	2024	5.3

[4] Full benefits will be realized when the full network has been commissioned (automation).

Dufferin Phase 2		12	2024	
Wiltshire Total	1	1	2025	0.3
Leaside Total	3	2	2025	0.7
Main Total	9	7	2025	2.3
Carlaw Total	9	7	2025	2.3
Strachan Total	9	7	2025	2.3

In the last two years, real-time loading data from commissioned network units was used by controllers during multiple contingency events to determine accurate loading conditions and improve operating decisions:

- In January 2022, a fire in a cable chamber was caused by the network's secondary cables. Loading analysis was required to determine if a widespread outage on the Windsor network would be required. Controllers used real-time loading data as the input and determined that it was possible to support a multiple contingency event to isolate the affected area without resulting in a large outage on the network.
- In February 2022, a fault occurred on the Cecil network which supplies highly sensitive customers such as banks and hospitals. Using the NCMC real-time data allowed the crews to identify the fault and re-energize the network in an hour. In addition, NCMC capabilities allowed Toronto Hydro to confirm that the network was able to operate on second contingency and avoid taking the network down completely.
- In February 2023, a feeder on the George and Duke network experienced a cable fault and a neighbouring feeder tripped shortly after, causing the need for an N-2 assessment. The use of real-time loading data determined that the multiple contingency event could be supported on the network.

Real-time loading also helps support planned work in addition to failures. Historically, when real-time loading data was not available, Toronto Hydro could not schedule an outage on multiple feeders and vaults simultaneously for planned work, as the specific impact to the network would not be known or definitive. For example, in April 2022, the Cecil network was assessed and confirmed through loading data that multiple feeders and vaults could be taken out of service to support planned work. This allowed the planned work to be scheduled on time.

Table 4 also shows the potential customer load that may be saved for each network during a multiple contingency event. These are estimated based on the avoidance of dropping one third of the network load once the whole network has NCMC capabilities.

Continued deployment of the Program will provide highly accurate peak readings of Toronto Hydro's network assets than can be achieved through summer vault inspections. From a planning perspective, engineers will be able to model the various parts of the system with greater accuracy and plan based on more accurate power flow models. Network customer requests can be challenging to handle, and accurate power flow models are essential for efficiently connecting customers. More efficient connections will result in lower-cost and faster customer connections, contributing to Toronto Hydro's compliance with OEB-prescribed objective to connect new services on time 90 percent of the time.

Toronto Hydro inspects and maintains its network vaults and equipment through the Preventative and Predictive Underground Line Maintenance program.[5] As a result of the implementation of NCMC, Toronto Hydro expects to reduce the number of planned vault inspections required for each network vault per year, reducing maintenance costs in that program by approximately $300 per vault starting in 2027. At the end of the NCMC program (e.g. once all vaults are commissioned), this will result in approximately $275,000 in maintenance costs avoided each year.

E7.3.3.3 Enhanced Monitoring Capabilities Post 2025

Toronto Hydro expects to complete the original objectives of the program by the end of 2025, at which point the utility plans to initiate a pilot project to further enhance real-time monitoring capabilities by exploring different types of additional sensors that can be installed in network vaults:

- **Fire sensor**: This will allow earlier detection of fire events and allow timely intervention to limit equipment damage as compared to the vault temperature sensor.
- **Analog Water Level Sensor**: The analog sensors will provide additional data (i.e. measure of actual water level versus just the presence/absence of water) to remotely assess flooding severity as compared to the binary water level sensors thus reducing dispatches to assess vault condition. It would provide a means for the Control Room to prioritize reactive crew allocation.

[5] Please see Exhibit 4, Tab 2, Schedule 2 for more details.

- **Video Camera**: These can help detect unauthorized intrusion, and provide remote verification of alarm or unsafe conditions. This would allow the crews to better understand the situation of the vault prior to entering.
- **Vault Hatch Open Sensor**: Identify unauthorized intrusion and mitigate risk to the public (access to energized vault or a tripping/fall hazard).
- **Secondary Cable Monitoring with Cable Sensors and a Remote Node Collector**: Enhance the ability to extend operation of secondary networks under second contingency by identifying when secondary cables reach critical overload. Also, it will allow monitoring of the loading and condition of secondary cables emanating from network protectors and provide timely detection of the operations of cable limiters which could result in complete or partial outage to customers.

Overall, these enhancements will assist Toronto Hydro in further reducing safety and reliability risks, and in strengthening the resilience of the grid. This will also help save important utility assets before they fail or reach end of life earlier than they should. Lastly, by early detection of potential catastrophic situations, the utility will be able to prevent major incidents from occurring.

E7.3.4 Expenditure Plan

The program aims to improve issues related to reliability, safety, failure risk, and system efficiency primarily by investing in monitoring and control equipment installations inside network vaults, as well as a fibre optic communications backbone installed under city streets. Table 5 below depicts the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) spending for this program.

Table 5: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Network Condition Monitoring and Control	8.1	12.5	13.0	11.0	12.2	4.2	0.2	0.4	0.6	0.6

The prioritization, scheduling and completion of projects in this program are based on the proposed fibre optic installation plan shown in Figure 4. Installation of the necessary fibre backbone is a prerequisite for testing and commissioning of monitoring and control equipment installed in individual vaults. Therefore, equipment installation in vaults is planned for the year following the completion of fibre installation. In addition, network units installed after 2010, including those to be replaced through the Network System Renewal program, will be equipped with the necessary relays and sensors required for monitoring and control. Network units that are retrofitted are also allocated within the budget under VCB installation.[6]

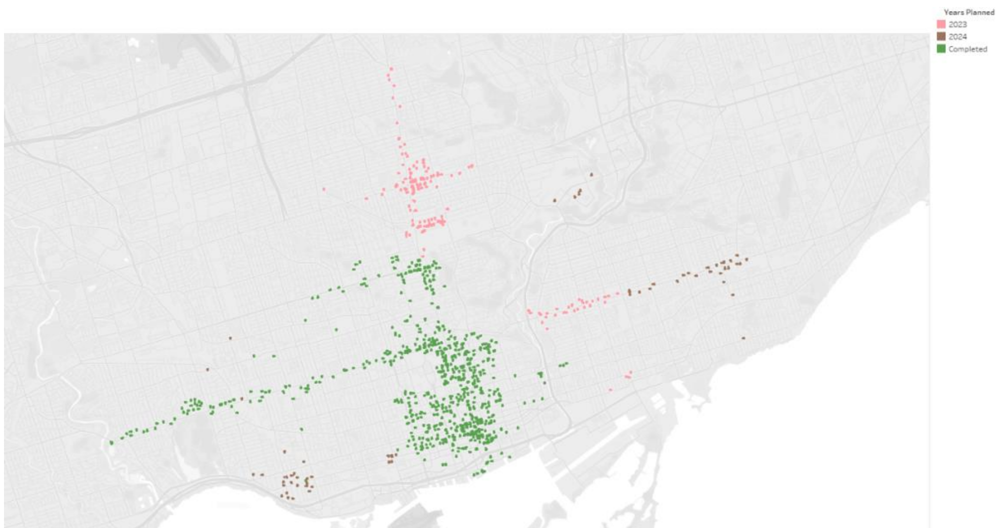

Figure 4: Fibre Optic Cable Deployment by Year

E7.3.4.1 2020-2024 Expenditures

Over the course of the Program so far, Toronto Hydro has commissioned 379 vaults, including 367 over 2020 to 2022. Toronto Hydro spent $33.6 million over 2020 to 2022 and plans to spend approximately $23.2 million and commission an additional 320 vaults over 2023 to 2024. Toronto Hydro no longer expects to complete the program by the end of 2024, as was originally proposed. As shown in Table 4, Toronto Hydro expects to complete commissioning of all except six of the networks proposed in the 2020-2024 DSP, four of which are the smallest networks by load.

The delays have been driven primarily by three factors. Firstly, fibre projects have been completed more slowly than expected due to execution challenges, such as resource constraints in 2020-2021, and additional time required to coordinate with external utilities to complete necessary civil work. Secondly, the work related to commissioning of the vaults started later than planned and the pacing

[6] Exhibit 2B, Section E6.4.

was also slower due to the learning curve from introducing new equipment, training requirements, and change management challenges. Thirdly, supply chain delays for VCBs caused work plans to slip and carry over into subsequent years. In 2022, the VCB supplier informed the utility of expected delays in acquiring the raw materials (brass sheets) required for manufacturing. To mitigate delays in program implementation, Toronto Hydro's engineers developed a new standard that allowed the VCB to be constructed from stainless steel. This innovation allowed Toronto Hydro to complete 129 of its planned 161 units before year-end as well as have a backup option to avoid any potential material delays. Remaining units have been scheduled and completed in Q1 2023.

It should be noted that while Toronto Hydro has been modernizing its system for many years, the NCMC program represents Toronto Hydro's first full-scale implementation of a new set of distributed grid technologies since the roll-out of the first generation of smart meters. While some challenges and delays have been encountered in this implementation, Toronto Hydro believes that the lessons learned, skills developed, and organizational capacity gained through this experience will support a successful and efficient implementation of the Grid Modernization Roadmap in the 2025-2029 rate period.

E7.3.4.2 2025-2029 Expenditure

Toronto Hydro plans to spend approximately $4.2 million in 2025 and commission the remaining 222 network vaults required to complete the original NCMC program plan. Any future renewal of the equipment installed through this Program and associated recommissioning work will be completed through the Network System Renewal program.

Over 2026 to 2029, Toronto Hydro plans to invest approximately $1.8 million to assess the viability of commissioning the remaining vaults not completed by 2025 as well as launch a pilot project that will install additional sensors, such as fire and analog water sensors, cameras, vault hatch open sensors and secondary cable monitoring, to further enhance monitoring capabilities in 35 network vaults (approximately 4 percent of network vaults). The network vaults targeted will be prioritized based on factors including, but not limited to history of flooding, higher voltage units, top entry vaults, and network grids where there is larger amount of secondary cabling. The investments in additional sensors will further improve real-time awareness in the network system, leading to improved decision making and pre-emptive response to different types of failures. These incremental investments will lead to substantial benefits as the investments already made in fibre and VCBs can be leveraged.

E7.3.5 Options Analysis

E7.3.5.1 Option 1: Sustainment

Under this option, Toronto Hydro will complete the original NCMC program plan in 2025, installing and commissioning monitoring and control equipment installations inside a total of 920 network vaults and providing associated reliability, safety, and system efficiency benefits. Once this is complete, Toronto Hydro would not do any additional work to further enhance real-time monitoring capabilities by installing additional sensors.

This option would forego additional modernization on the network system and limit the value of the upfront investments made on the infrastructure to enable NCMC. Benefits from future developments and technology in network system modernization would be missed, including substantial reliability, resiliency and efficiency benefits, as described in more detail in Sections E7.3.3 and E7.3.4.2.

E7.3.5.2 Option 2: Improvement

Under this option, the same as under Option 1, Toronto Hydro will complete the original NCMC program plan in 2025. Once that is complete, Toronto Hydro plans to initiate a pilot project to further enhance real-time monitoring capabilities by installing additional sensors, such as fire and analog water sensor, vault camera, vault hatch open, and secondary cable monitoring in 35 network vaults over 2026 to 2029. This additional monitoring will further improve awareness of the condition and operation of the vault and network assets, leading to further enhanced decision making, reduction of failures, and improved safety for internal crews and the public. The additional sensors will leverage equipment and infrastructure already in place such as fibre and VCBs, thereby maximizing overall benefits of the upfront investments in the program.

Under this option, Toronto Hydro will complete the original NCMC program plan in 2025. Once complete, Toronto Hydro plans to initiate a pilot project to further enhance real-time monitoring capabilities by installing additional sensors, such as fire and analog water sensor, vault camera, vault hatch open, and secondary cable monitoring in 35 network vaults over 2026 to 2029. This additional monitoring will further improve awareness of the condition and operation of the vault and network assets, leading to further enhanced decision making, reduction of failures, and improved safety for internal crews and the public. The additional sensors will leverage equipment and infrastructure already in place such as fibre and VCBs, thereby maximizing overall benefits of the upfront investments in the program.

E7.3.6 Execution Risks & Mitigation

E7.3.6.1 Fibre Installation

Fibre optic cable is the first asset that must be installed as part of the Program. Installation of fibre under city streets poses a number of risks that may cause program delays and increase costs, including:

- Lack of existing duct capacity for the fibre optic cable;
- Road construction moratoriums and road work restrictions;
- Construction blocking access to cable chambers and vaults; and
- Leaking cables posing hazards that prevent workers from entering cable chambers and vaults.

If a problem is only identified once construction begins, it results in reactive work, increased cost, and program delays. Toronto Hydro mitigates these risks by performing detailed field inspections during the design phase of the program and then designing solutions that avoid problem locations altogether. Alternatively, Toronto Hydro can plan ahead for necessary construction work to avoid impacting the program's critical path timeline. Toronto Hydro has piloted the use of wireless technology in NCMC applications by utilizing a long-term evolution ("LTE") communication device to connect to SCADA systems. If successful, this technology will provide an alternate way to add NCMC capabilities to network vaults by enabling remote connection where fibre optic communication cannot be deployed due to the risks mentioned above.

E7.3.6.2 Vault Equipment Installation

Certain risks can delay the installation of equipment inside network vaults and increase costs, including:

- Flooded vaults;
- Lack of suitable available space to install equipment;
- Existing primary feeder installation interfering with the installation of transformer sensors; and

- Legacy protectors not compatible with newer communicating relays required for NCMC.

Toronto Hydro mitigates all of these risks by performing a detailed field inspection during the design phase. Toronto Hydro can complete corrective work on flooded vaults prior to starting construction work for this program. To address a lack of suitable available space to install equipment, such issues will be proactively identified, and the relevant project will be designed to include the necessary equipment relocation work and scheduled to avoid impacting the program's critical path timeline. Where existing primary feeder installations interfere with installation of a particular transformer sensor and incompatible legacy network protectors, Toronto Hydro will complete a network unit renewal and then install NCMC capabilities.

E7.3.6.3 Material Delays

Supply chain issues can cause delays in receiving material for all NCMC components and therefore delay execution of projects, as was the case with VCBs in the 2020-2024 rate period, as discussed in section E7.3.4.1. Toronto Hydro mitigates this risk by ensuring all relevant stakeholders are engaged to proactively identify issues and develop solutions, such as developing new standards that increase options available. This is also mitigated through Toronto Hydro's procurement strategy. For more details on this procurement strategy and what Toronto Hydro has been doing to address this issue, please see Exhibit 4, Tab 2, Schedule 15 (Supply Chain).

E7.3.6.4 Security and Privacy Issues

Once the initial plan of the program is completed, Toronto Hydro plans to introduce enhanced monitoring capabilities, which may include vault cameras and vault hatch open sensors. These two sensors pose security and privacy issues that need to be resolved prior to planning installations. However, Toronto Hydro is making investments in IT Cybersecurity to ensure that current systems, applications, and endpoints can continue to operate reliably and with minimal risk exposure to cyber threats in response to an evolving threat landscape, please refer to Exhibit 2B Section E8.4 for more details.

In addition, secondary cable monitoring sensors will pose data overload issues and cables identified for sensor installation need to be carefully selected to provide useful benefits for system emergency operations as well as planning enhancements. These concerns will be discussed with the appropriate stakeholders before rolling out these sensors, and will be considered alongside other modernization initiatives in the context of Toronto Hydro's broader analytics strategy.

E7.4 Stations Expansion

E7.4.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 139.9	**2025-2029 Cost ($M):** 173.2
Segments: Downsview TS, Hydro One Contributions[1]	
Trigger Driver: Capacity Constraints	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Public Policy Responsiveness, Environment	

Toronto Hydro's Stations Expansion program (the "Program") addresses medium to long-term system capacity needs. The Program is driven by capacity constraints at the station or regional level, which can no longer be effectively managed by the Load Demand program alone. Increased and continued densification, population growth, and electrification are driving the need to relieve the station loading and create additional capacity. If not addressed proactively, this will impact Toronto Hydro's ability to connect customers to its distribution system, and expose Toronto Hydro's stations to risk during peak loading periods. The primary focus of the work planned in the 2025-2029 rate period is on the horseshoe northwest and horseshoe east regions of the distribution system, where constraints currently exist or are forecasted to materialize with growth.

The Stations Expansion program consists of the two segments summarized below, and is a continuation of the expansion activities described in Toronto Hydro's 2020-2024 Distribution System Plan.[1]

- **Downsview TS**: This segment aims to expand station capacity by constructing a new transformer station ("TS") in the Downsview area of Toronto, with a capacity of 174 MW. Additional capacity is needed to support forecasted growth and development in the City's Downsview area, while relieving the highly-loaded Bathurst and Finch TSs. A demand study of the Downsview area has forecasted a load demand of 195 MW by 2035.[2] The construction of a new TS is a large project requiring a long lead time. In order to be ready to meet the forecasted demand, Toronto Hydro must start planning and preparing for this project in the

[1] EB-2018-0165, Exhibit 2B, Section E7.4
[2] Downsview Area Secondary Plan – Electricity Demand Justification Report by DMP Energy (Aug 08 2022)

2025-2029 rate period for an anticipated energization date of late 2033. This planning and preparation stage will include preparatory capital investments such as: property acquisition, property site preparation construction of a new station building, high voltage circuit breakers and bus work, and partial construction or payments towards station assets.[3] Toronto Hydro forecasts to spend $70.2 million in this stage. Once planning and preparation is complete, Toronto Hydro will move into the construction and energization stage, which will include the installation of the remaining electrical assets, the installation of station ancillary assets, and the commissioning and energization of all electrical assets. Toronto Hydro forecasts to spend $70.0 million during the commissioning and energization stage post-2029.

- **Hydro One Contributions:** this segment covers Toronto Hydro's forecasted capital contributions to Hydro One for work related to:
  - Downsview SS: A new Hydro One switching station to provide Toronto Hydro's new Downsview TS access to Hydro One's transmission network;
  - Scarborough TS Expansion: A new Dual Element Spot Network ("DESN") at the existing Scarborough TS to provide relief to the Horseshoe East area and support future load growth;
  - Sheppard TS New Switchgear: A new switchgear to provide access to existing idle capacity at the existing Sheppard TS and enable new Distributed Energy Resources (DER) connections [E3.3 Capacity and Constraints to Connect DER];
  - Manby TS T13/T14 DESN Upgrade: An upgrade to the transformers at this DESN during their natural end-of-life (EOL) renewal and an expansion of the switchyard to accommodate new feeders, to facilitate future load growth at this highly loaded station; and
  - Cost-effective capacity upgrades of EOL Hydro One-owned power transformers, as anticipated based on the IRRP process and latest Planning work in 2022.[4]

  Toronto Hydro plans to invest an estimated $103.0 million in this segment in the 2025-2029 rate period compared to a forecasted $60.4 million in 2020-2024.

The investments summarized above for Hydro One transformer replacement are informed by the recent Regional Infrastructure Plan ("RIP") and 2020 Integrated Regional Resource Plan ("IRRP")

[3] Site preparation will include items such as, but not limited to, the clearing of land, construction of a ground grid, installation of crushed stone, and a station fence.
[4] Hydro One Needs Assessment Report, Toronto Region, Dec 2022

activities conducted in coordination with Hydro One. The most recent planning document from this process is the 2022 Needs Assessment Report for the Toronto Region ("Needs Assessment"). A reconciliation of the Needs Assessment with Toronto Hydro's Stations Expansion program is found in Section E7.4.7 Regional Planning Needs of this narrative.

The Stations Expansion program also responds to the need to maintain system reliability and increase grid resiliency to support Ontario public policy drivers. To this end, the Program focuses on Toronto Hydro's broad strategy of grid modernization within the context of an aging, dense urban infrastructure, aiming to support customers and load growth and both mitigating and adapting to climate change through grid resiliency and innovation.

In total, Toronto Hydro plans to invest $173.2 million in the Stations Expansion Program in 2025-2029, compared to a forecasted $139.9 million in 2020-2024. Toronto Hydro expects to add 321 MW of new capacity to its system from projects completed by 2029, and start projects that will contribute to an additional 269 MW of capacity when completed in 2030-2034.[5]

E7.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Reducing the number of stations unable to connect new large customers in the downtown and Horseshoe areas by investing in 321 MW in additional supply capacity by 2029; ○ Alleviating feeder position limitations that prevent customer connections; and ○ Enabling new DER connections by providing increased short-circuit capacity with new DESNs.
Operational Effectiveness - Reliability	• Contributes to maintaining Toronto Hydro's system capacity and reliability objectives by: ○ Providing redundancy and operational flexibility by upgrading capacity at supply points to keep the number of highly loaded stations (with loads > 90 percent capacity) at a minimum for the downtown and Horseshoe areas;

[5] The Downsview TS and Scarborough TS Expansion projects will contribute 271 MW of new capacity and are forecasted to come in-service during the 2030-2034 rate period.

Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy objectives by: ○ Supporting the provincial long-term energy planning and IRRP by meeting local needs; and ○ Enabling electrification by investing in additional capacity and operational flexibility.
Environment	• Contributes to Toronto Hydro's environmental objectives by investing in capacity to support operational flexibility, enable electrification.

E7.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Capacity Constraints
Secondary Driver(s)	Reliability, DER Connections

The Stations Expansion program is driven by constraints at the station or regional level, which can no longer be effectively managed by the Load Demand program alone. Over the next decade, Toronto Hydro's distribution system is expected to face many new challenges and demands due to population growth, densification, and electrification. These factors will ultimately result in increased capacity constraints at its stations, creating the need to relieve constraints by building additional capacity.

Because these challenges, particularly the acceleration of electrification, are subject to many factors outside of Toronto Hydro's control, such as government policies and consumer preferences, the timing for when capacity constraints will materialize is uncertain. Toronto Hydro has managed this uncertainty by considering multiple inputs to develop a plan that will satisfy its capacity needs, in a least-regrets investment approach. These inputs are as follows.

- **Load Forecasts:** Toronto Hydro's 10-Year Peak Demand Forecast (see Section D of the Distribution System Plan), and Hydro One's Needs Assessment Report 10-Year Load Forecast
- **City of Toronto Development Plans:**[6] Downsview Area Secondary Plan, East Harbour Development, Golden Mile Secondary Plan, and Scarborough Centre Secondary Plan

[6] City of Toronto, Secondary Plan Key Map (November 2015) https://www.toronto.ca/wp-content/uploads/2017/11/980a-cp-official-plan-Map-35_SecondaryPlans_AODA.pdf

- **Future Energy Scenarios ("FES"):**[7] Six scenario-based outlooks to assess impacts to station loading due to: the electrification of heating and transportation, building stock growth, and DER integration.

From this analysis, Toronto Hydro identified that the City of Toronto Development Plans will be a primary driver of forecasted load growth in both the Downtown and the Horseshoe areas. Toronto Hydro expects that these plans will result in load growth that will add constraints to the Bathurst TS and Scarborough TS areas over the next 5-10 years.

A second key driver of forecasted load growth identified is electrification, which is forecasted to impact Toronto Hydro's system more broadly than the Secondary Plans which target specific areas. This is driving a need for capacity to be made available throughout Toronto Hydro's system, to ensure that Toronto Hydro's system does not become a barrier to new customers looking to access its system, regardless of where those customers may materialize.

The lack of capacity at Toronto Hydro's stations results in two negative consequences. First, it negatively impacts customer connections by preventing new customers from connecting to the grid or burdening connecting customers with higher connection costs. Second, it reduces the reliability of the station, and may result in load shedding.[8]

When a customer submits a connection request to a station which is highly loaded, Toronto Hydro can either connect the customer to the highly loaded station by first completing a load transfer, or to another station with capacity further away resulting in a higher connection cost. When multiple neighbouring stations are highly loaded, these options become even more limited, and connection costs become even higher.

When station load exceeds capacity, equipment losses result in customer outages during periods of peak loading. As a result, Toronto Hydro or Hydro One is not able to complete maintenance or replacement work during peak periods, which typically results in the deferral of work needed to maintain station reliability. To otherwise complete the work during peak periods would result in a shortened life of the existing station assets, which cannot be readily replaced. A lack of station

[7] Exhibit 2B Section D4 Capacity Planning & Electrification
[8] Load Shedding is the process during which Toronto Hydro temporarily shuts down power supply to a limited number of customers, in order to reduce its station load beneath its station capacity. Power supply is restored to customers when doing so would no longer result in an overload. When needed, load shedding is generally rotated across customers for a few hours each, so that no customers experience long duration outages while others experience no outages at all.

capacity results in reduced reliability at the station, which affects tens of thousands of customers and typically 100-300 MW of customer load per station. Because of the significant consequences in the event of an outage, Toronto Hydro would be required shed load[8] to maintain station load within its capacity.

Hydro One's 2022 Needs Assessment, as part of Regional Planning identifies station capacity needs at: Bathurst and Finch TSs, Basin TS, Fairbank TS, Glengrove TS, Sheppard TS, Strachan TS, and Warden TS. The Report also recommends incremental capacity upgrades at Basin TS, Duplex TS, Manby TS, and Strachan TS during renewal work. Toronto Hydro's analysis has reached similar conclusions; and as a result, the work planned under the Stations Expansion Program is aligned with the NA needs and those in the 2020 Regional Infrastructure Plan ("RIP") report.[9] Table 4 and Table 5 below highlight the needs and how they are addressed through the Stations Expansion program.

The IESO's Integrated Regional Resource Plan ("IRRP")[9] for the Toronto Region is currently underway, and as a result, IRRP needs and recommendations have not been produced at this time. However, Toronto Hydro is presenting the same needs to the Toronto IRRP Working Group as those presented in the Stations Expansion Program.

Table 4: Station Capacity Needs from Needs Assessment and RIP

Station Capacity Need	Needs Assessment Report Timing	Needs Assessment Report Section	RIP Report Section	Stations Expansion Narrative
Bathurst TS / Finch TS	*Beyond 2031*	*7.3.6*	*N/A*	See E7.4.3.2.1
Basin TS	*2030-2035*	*7.3.4*	*7.9.4*	See E7.4.3.2.2
Fairbank TS	*2030-2035*	*7.3.1*	*7.9.1*	Included in 2020-2024 Stations Expansion plan, and in E7.4.3.2.1.
Glengrove TS	*Beyond 2031*	*7.3.5*	*N/A*	Addressed with new capacity at Duplex TS in E7.4.3.2.6
Sheppard TS	*2030-2035*	*7.3.2*	*7.9.2*	See E7.4.3.2.4

[9] Exhibit 2B, Section B, Appendix A, B, C, D, and E

Station Capacity Need	Needs Assessment Report Timing	Needs Assessment Report Section	RIP Report Section	Stations Expansion Narrative
Strachan TS	*2030-2035*	*7.3.3*	*7.9.3*	Addressed through transformer upgrade in E7.4.3.2.6
Warden TS	*Beyond 2031*	*7.3.7*	*N/A*	See E7.4.3.2.3

Table 5: NA Asset Renewal Needs where Upgrade is Recommended in NA and RIP

<table>
<tr><th>Asset Renewal Need</th><th>Renewal Timing[10]</th><th>Needs Assessment Section</th><th>RIP Report Section</th><th>Stations Expansion Narrative</th></tr>
<tr><td>Basin TS T3/T5 Transformers</td><td>2027</td><td>7.1.4</td><td>N/A</td><td rowspan="7">See E7.4.3.2.6</td></tr>
<tr><td>Charles TS T3/T4 Transformers</td><td>2026</td><td>7.1.2</td><td>N/A</td></tr>
<tr><td>Duplex TS T1/T2 Transformers</td><td>2026</td><td rowspan="2">7.1.3</td><td rowspan="2">N/A</td></tr>
<tr><td>Duplex TS T3/T4 Transformers</td><td>2031</td></tr>
<tr><td>Manby TS T13/T14 Transformers</td><td>2030</td><td>7.1.9</td><td>7.6</td></tr>
<tr><td>Strachan TS T14 Transformer</td><td>2025</td><td rowspan="2">7.1.1</td><td rowspan="2">N/A</td></tr>
<tr><td>Strachan TS T13/T15 Transformers</td><td>2031</td></tr>
<tr><td>Windsor TS (John TS) T2/T3 and T5/T6 Transformers</td><td>2026</td><td>N/A</td><td>7.8</td><td>Included in 2020-2024 Stations Expansion plan.</td></tr>
</table>

The station expansion program continuously improves and expands Toronto Hydro's grid in order to align itself with the City's growth and electrification endeavors. The work in the station expansion program will make Toronto Hydro's system more resilient to sudden load demands, and will ensure sufficient capacity exists to ensure station reliability.

[10] If present in both the NA and RIP, the NA timing is used, as the NA is the more recent document.

The system needs are addressed through two segments: Downsview TS and Hydro One Contributions, as further discussed below.

E7.4.3.1 Downsview TS

The area affected by the Downsview TS segment consists of: Bathurst TS, Fairbank TS, Fairchild TS, and Finch TS. This area will be called the "Downsview Area" throughout the rest of this document. The Downsview Area is show in Figure 1.

In recent years, the Downsview Area has been attracting a large quantity of new load, and that trend is forecasted to persist into the future. On average, the area is forecasted to grow by 2.2 percent per annum over the next 10 years.

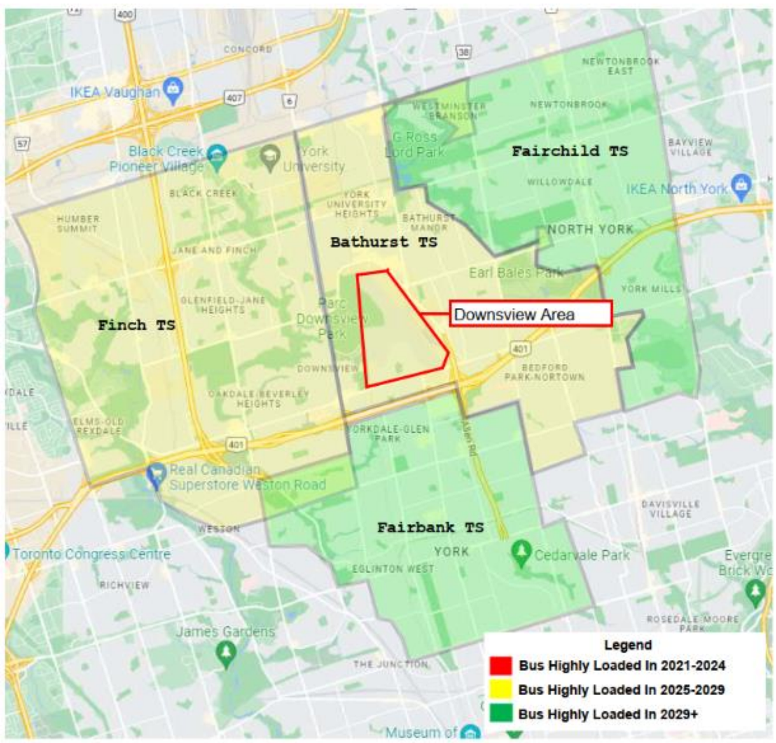

Figure 1 : Service Territories of Stations in the Downsview Area

1. Toronto Hydro's Peak Demand Forecast

Table 6 shows the existing load forecast for the stations in the Downsview Area based on firm connection requests, as provided in Toronto Hydro's Peak Demand Forecast.

Table 6 : Non-Coincident Downsview Area 10-Yr Load Forecast11

Station	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bathurst TS	361	73%	78%	79%	85%	86%	86%	85%	85%	85%	85%	85%
Fairbank TS	182	104%	104%	94%	93%	95%	97%	97%	98%	100%	101%	103%
Fairchild TS	346	61%	67%	67%	69%	69%	69%	70%	70%	70%	71%	71%
Finch TS	366	69%	77%	90%	98%	100%	102%	102%	103%	104%	105%	107%
Area Non-Coincident %	1255	73%	78%	81%	85%	86%	88%	88%	88%	89%	89%	90%

Fairbank TS and Finch TS are forecasted to be highly loaded during the 2025-29 rate period, with both stations forecasted to be overloaded by 2029. Fairbank TS has historically been highly loaded, and is being relieved by the recent expansion work at Runnymede TS; nonetheless, the station remains highly loaded and requires subsequent relief. Some capacity remains at Bathurst TS, but not enough to relieve overloading. Fairchild TS remains as the only station with significant capacity in the Downsview Area, but it cannot provide direct relief to the highly loaded Fairbank and Finch TSs, due to geography.

Despite remaining capacity at Bathurst and Fairchild TSs, and the practical challenges of utilizing Fairchild TS for relief, the entire Downsview Area is forecasted to reach 90% loading by 2031. This signals a lack of capacity at the regional level, which is needed to support new connections, growth, and electrification.

In addition to the impacts from the Peak Demand Forecast, Toronto Hydro is considering the longer-term impacts to the Downsview Area resulting from the Downsview Secondary Development Plan, and its Future Energy Scenarios outlooks. These are described in the subsections below.

[11] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.

2. Downsview Area Secondary Plan ("DASP")

The Downsview Lands are approximately 210 hectares (520 acres) situated in the City of Toronto, bounded by Sheppard Avenue to the north, Allen Road to the East, Wilson Avenue to the south, and Downsview Park and the Park Commons to the west, as shown in Figure 2. The lands reside within the Bathurst TS service territory, as shown in Figure 1.

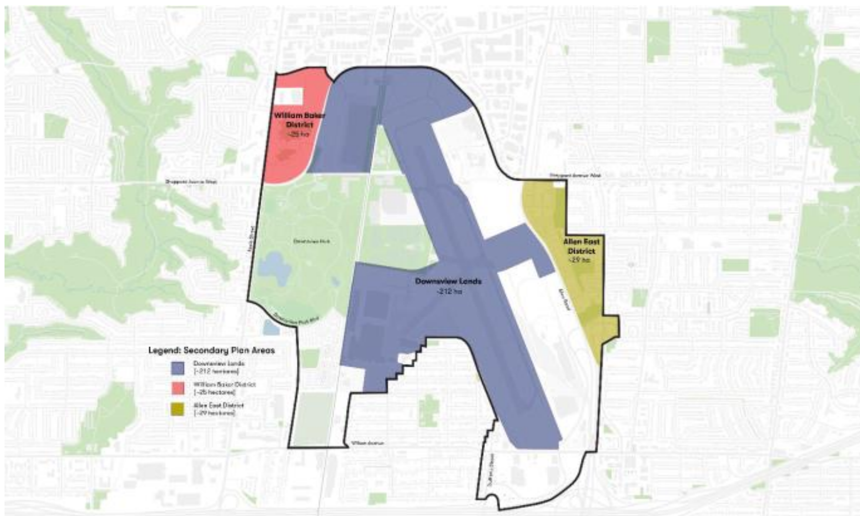

Figure 2: Proposed Downsview Secondary Plan Lands

The City of Toronto plans to redevelop the Lands into a dense new community as described in their Downsview Area Secondary Plan ("DASP"), published in 2017.[12] The DASP divides the Downsview Lands into districts and describes the expansion of each district with a mix of commercial, office, industrial and institutional buildings. The DASP preceded the city's net zero 2040 plans but is to align with the adoption of current day power demands of 6W per square foot and EV chargers for the projected EVs by 2045.

An independent party, DPM Energy, completed a preliminary study which estimates the electrical demand that will materialize from the DASP. This study suggests that load will begin to materialize in 2022 and could materialize up to: 103 MW by 2029, 180 MW by 2034, and 509 MW by 2051. This is equivalent to 8%, 14%, and 41% of the existing Downsview Area's Summer LTR of 1255 MW, as provided in

[12] City of Toronto, Downsview Area Secondary Plan, "online", https://www.toronto.ca/wp-content/uploads/2017/11/902d-cp-official-plan-SP-7-Downsview.pdf

Table 6. As a result, supplying the Downsview Lands with existing regional capacity will not be feasible without capacity investments.

The Peak Demand Forecast only extends to 2031, and already considers load growth from the DASP. However, the DASP is expected to result in load growth up to 2051, with the majority of load materializing after 2031. Therefore, in order to ensure that cost-effective decisions are made now for the long term, Toronto Hydro has developed a 25 Year Forecast for the Downsview Area which considers the impact of the DASP from 2029 onwards. The 25 Year Forecast is based on the following assumptions:

1. **The annual load growth of the DASP for 2032-2051 is adjusted to 70 percent.**
   - Toronto Hydro's standard bus load forecasting methodology adjusts new customer load to 70% of the requested load in order to forecast bus load impacts. This reduction is based on historical results of customer load materialization.
2. **The 30 percent reduction to the DASP load for 2032-2051 is offset by:**
   - Load growth due to electrification of heating and transportation in the Downsview Area, in alignment with municipal and federal decarbonization goals.
   - General load growth in the Downsview Area, beyond the Downsview Lands.

Based on these assumptions, Toronto Hydro has adopted the 25 Year Forecast as the load forecast for the entire Downsview Area for post-2031. The results appear in Table 7.

Table 7 : Post-2031 Forecast for Downsview Area

Station	Summer LTR (MW)	2031	2034	2039	2044	2049	Year 100% Capacity is Reached
Bathurst TS	361	86%	90%	98%	108%	117%	2040
Fairbank TS	182	111%	115%	124%	133%	142%	2029
Fairchild TS	346	71%	71%	71%	71%	71%	N/A
Finch TS	366	110%	113%	117%	121%	126%	2025
Area Non-Coincident %	1255	93%	95%	100%	105%	111%	2039

This forecast shows that by 2039 the Downsview Area as a whole will reach capacity, with substantial load growth continuing past then. Prior to that, significant overloading is forecasted at Fairbank TS and Finch TS, which cannot be directly relieved by Fairchild TS, the only station with capacity, due to geography. The 25 Year Forecast indicates that regional capacity constraints will persist past the medium term, and worsen further into the long term.

3. Load Projections – FES

To consider the impacts that the electrification of heating and transportation, building stock growth, and DER integration may have on Toronto Hydro's station loading, Toronto Hydro completed the FES[7]. The FES produced six 30-year system and station bus load projections based on different scenarios.

The FES incorporates current growth trends, econometric factors, and electrification goals into its modeling, but does not incorporate any DASP load. The results from the FES outlooks are provided in Table 8.

Table 8 – FES Projections for the Downsview Area

Station	Summer LTR (MW)	2031	2034	2039	2044	2049	Year 100% Capacity is Reached[13]
Bathurst TS	361	84-94%	89-101%	95-114%	99-118%	98-122%	2034-N/A
Fairbank TS	182	120-132%	124-142%	130-167%	132-174%	131-180%	2021
Fairchild TS	346	68-74%	69-78%	70-84%	70-85%	69-86%	N/A
Finch TS	366	113-122%	118-133%	124-150%	127-153%	126-156%	2024
Area Non-Coincident %	1255	93-102%	97-109%	102-122%	104-126%	103-129%	2030-2037

Across all FES projections, all but one station will become heavily loaded by 2035. Additionally, the Downsview Area is to become highly loaded between 2025-28, and overloaded between 2030-37. Consistent with the Peak Demand Forecast and Toronto Hydro's post-2031 Forecast, the FES projections indicate high loading in the 2025-29 rate period, and a regional need for additional capacity that increases with time.

[13] According to the FES only. As a result, this year may be earlier than what is provided in the Needs Assessment.

4. Proposed Solution – New Downsview TS

In order to address both medium- and long-term regional needs for additional capacity in the Downsview Area, Toronto Hydro proposes to build a new transformer station, named Downsview TS. The objective of the new Downsview TS is both to provide load relief to the existing TSs in the Downsview Area, and to directly supply the new loads resulting from the DASP and electrification.

Downsview TS is proposed to be located within the Downsview Lands, within the Bathurst TS service territory. This location has been chosen so that it may directly supply local DASP loads, and because it is also a central location between Bathurst TS, Fairbank TS, and Finch TS. As a result, the station will be well-placed to offload the three highest loaded stations in the Downsview Area. Downsview TS will provide 174 MW of new capacity to supply the Downsview Area, increasing the Area's capacity by an additional 14%.

There will be both a Toronto Hydro and Hydro One component of work to construct the new Downsview TS. The Hydro One portion is discussed in E7.4.3.2 and involves the construction of a new Downsview Switching Station ("Downsview SS"), which will serve as the connection point to Hydro One's transmission network.

The construction of a new TS is a large project requiring a particularly long lead time, and for this reason, a portion of the work needed to build the new TS was advanced into the 2025-2029 rate period. In order to energize Downsview TS at the end of 2033, Toronto Hydro forecasts that work must begin in 2025. Toronto Hydro has planned for the Downsview TS project to proceed in two stages. The Planning and Preparation stage and the Construction and Energization stage.

The Planning and Preparation stage will proceed over the 2025-2029 rate period, and will include preparatory capital investments such as: property acquisition, property site preparation, construction of a new station building, high voltage circuit breakers and bus work, and partial construction or payments towards station assets.[14] The cost to complete this stage is forecasted to be $70.2 million.

The Construction and Energization stage will proceed starting in 2030 and will include the installation of the remaining electrical assets, the installation of station ancillary assets, and the commissioning

[14] Site preparation will include items such as, but not limited to, the clearing of land, construction of a ground grid, installation of crushed stone, and a station fence.

and energization of all electrical assets. The remaining electrical assets include: a new 230 kV underground cables from Downsview SS, two new transformers, and one new switchgear. Toronto Hydro forecasts to spend $70.0 million during this stage, excluding the Hydro One contributions related to Downsview SS (see E7.4.3.2 – 1.).

Because the forecasted in-service date is beyond the range of the Peak Demand Forecast, the effect of Downsview TS is provided using the Post-2031 Forecast and the FES load projections, and shown in Figure 3. With the addition of new capacity at Downsview TS, the Downsview Area loading is expected to be manageable out to 2041; after that the Area is again expected to be highly loaded, with a risk of overloading. FES Projections show that there is risk of Area overloading as early as 2036, and the magnitude of the potential overloading increases with time. To mitigate the risk of overloading in the long term, Downsview SS is proposed to be constructed with the provision to install a second DESN in the future, when it is needed.

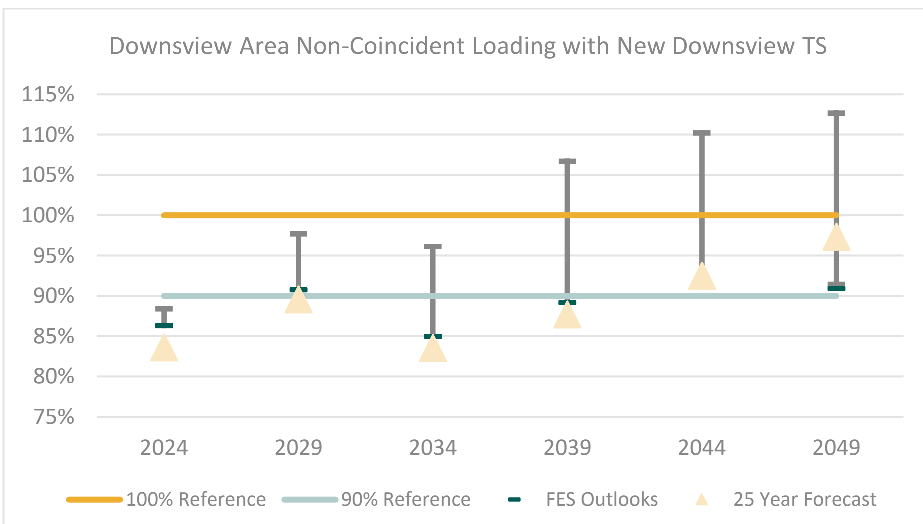

Figure 3 : Downsview Area Loading Outlooks After Downsview TS is In-Service

Toronto Hydro believes that the proposed solution strikes the right balance between the risk of capacity constraints and cost in least-regrets investment approach. Toronto Hydro will continue to monitor the actual and forecasted load of the Downsview Area to assess the risk of capacity constraints shortly after Downsview TS is completed. If this risk persists, Toronto Hydro may consider introducing another DESN into the Downsview Area at a later time; however, it would not be in the best interest of the ratepayer to invest immediately in two new DESNs. For this reason, the proposed solution includes only one new DESN, which is expected to provide adequate capacity until 2041.

E7.4.3.2 Hydro One Contributions

The most recent Needs Assessment reaffirms needs that were identified in the IRRP and highlights additional emerging needs. These needs are summarized in Table 32, Table 33, and Table 34 in Section E7.4.7.

In response, Toronto Hydro plans to make capital contributions to Hydro One to carry out upgrades at Hydro One stations during the 2025-2029 rate period, as detailed in the following subsections.

1. **New Downsview SS**

Toronto Hydro plans to make a capital contribution to Hydro One over the 2025-2029 rate period to support their construction of a new Hydro One-owned Downsview SS. As discussed in section E7.4.3.1 above, the Downsview TS will provide additional capacity of 174 MW to alleviate forecasted constraints in the Downsview Area. Hydro One will support the project by constructing a new switching station, Downsview SS, to supply Downsview TS from the Hydro One 230 kV transmission line corridor. Toronto Hydro will construct and own the TS itself.

2. **Scarborough TS Expansion**

The area affected by the Scarborough TS expansion consists of: Bermondsey TS, Ellesmere TS, Scarborough TS, and Warden TS. This area will be called the "Scarborough Area" throughout the rest of this document. The Scarborough Area is show in Figure 4.

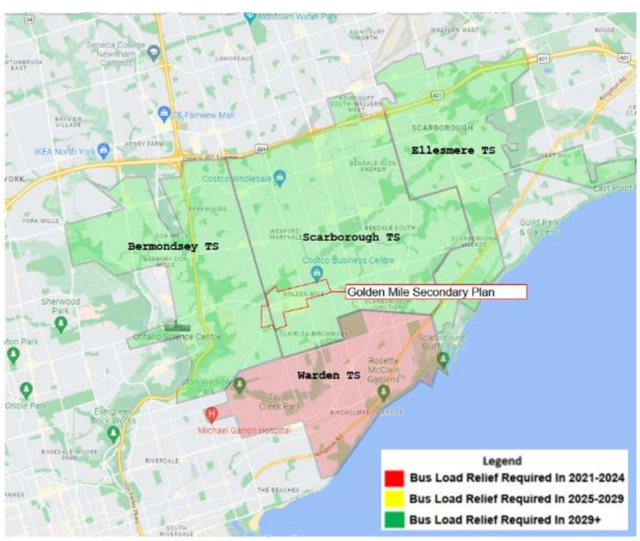

Figure 4 : Service Territories of Stations in the Scarborough Area

a. *Toronto Hydro's Peak Demand Forecast*

In recent years, the Area has been attracting a large quantity of new load, and that trend is forecasted to persist into the future. Recent large projects in progress involve an 84 MVA data centre, an 80 MVA Metrolinx connection for the Ontario Line, and a 36 MVA TTC connection for the Scarborough Subway Extension. On average, the area is forecasted to grow by 4.1 percent per annum over the next 10 years.

Table 9 shows the existing load forecast for the stations in the Scarborough Area based on firm connection requests, as provided in Toronto Hydro's Peak Demand Forecast.

Table 9: Non-Coincident Scarborough Area 10-Yr Load Forecast15

STATION	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bermondsey TS	348	45%	57%	67%	71%	73%	73%	85%	85%	85%	86%	88%
Ellesmere TS	189	63%	65%	71%	84%	88%	88%	89%	95%	96%	96%	96%
Scarborough TS	340	64%	68%	71%	78%	79%	79%	79%	84%	85%	86%	86%
Warden TS	182	80%	85%	78%	91%	92%	94%	93%	93%	94%	94%	95%
Area Non-Coincident %	1059	60%	67%	71%	79%	81%	81%	85%	88%	88%	89%	90%

Loading at all four stations in the Scarborough Area is forecasted to rapidly increase due to the onset of new large customer connections. Warden TS and Ellesmere TS particularly are forecasted to become highly loaded during the 2025-29 rate period. These two TSs will not be able to accommodate new large connection requests without first initiating load relief projects. By 2031, the entire Scarborough Area is forecasted to be highly loaded at 90% of capacity. This signals a lack of capacity at the regional level, which is needed to support new connections, growth, and electrification.

In addition to the impacts from the Peak Demand Forecast, Toronto Hydro is considering impacts to the Scarborough Area resulting from the Golden Mile and Scarborough Centre Secondary

[15] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.

Development Plans, and its Future Energy Scenarios projections. These are described in the subsections below.

b. Golden Mile Secondary Development Plan ("GMSDP")

In 2020, the City of Toronto adopted the Golden Mile Secondary Plan, which proposes a mixture of residential, commercial, and office building development. The Golden Mile is 113 hectares (280 acres) in size, generally bounded by Victoria Park Avenue to the west, Ashtonbee Road/Hydro Corridor to the north, Birchmount Road to the East and an irregular boundary to the south, as shown in Figure 5. The location of the Golden Mile relative to Toronto Hydro's station service territories is shown in Figure 4 in the previous section.

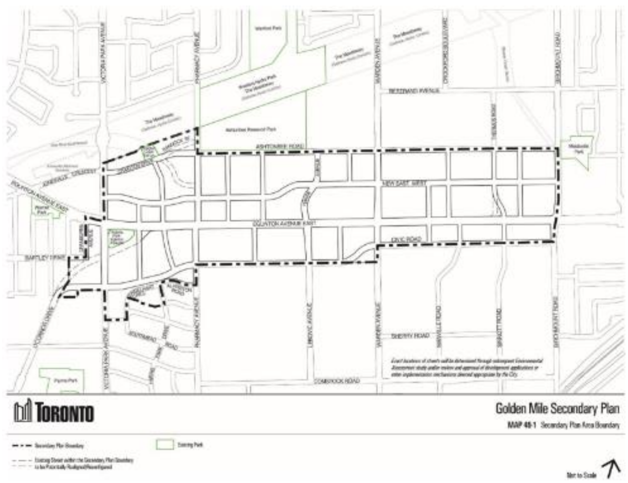

Figure 5 *:* Proposed Golden Mile Secondary Plan Lands

New developments are to include a mixture of mid-rise and tall buildings, creating up to 5,000 new residential units. Additionally, the Plan proposes for each dwelling unit to provide an energized outlet for EV charging. Based on the Plan, an independent party has completed a preliminary study which estimates the electrical demand that will materialize from the Golden Mile Secondary plan. This study suggests that load will begin to materialize in 2030 and could materialize up to 280 MW by 2040. This is equivalent to 26 percent of the existing Scarborough Area's Summer LTR of 1059 MW, as provided in Table 9. As a result, supplying the Golden Mile with existing regional capacity will be challenging at best in the short term, and infeasible in the long term.

The Peak Demand Forecast only extends to 2031, and does not already explicitly consider the GMSDP. In order to ensure that cost-effective decisions are made now for the long term, Toronto

Hydro has developed a 25 Year Forecast for the Scarborough Area which considers the impact of the GMSDP from 2030 onwards. The 25 Year Forecast is based on the following assumptions:

1. **The annual load growth of the GMSDP for 2030-2051 is adjusted to 70%.**
   - Toronto Hydro's standard bus load forecasting methodology adjusts new customer load to 70% of the requested load in order to forecast bus load impacts. This reduction is based on historical results of customer load materialization.
2. **The 30% reduction to the GMSDP load for 2030-2051 is offset by:**
   - Load growth due to electrification of heating and transportation in the Scarborough Area, in alignment with municipal and federal decarbonization goals.
   - General load growth in the Scarborough Area, beyond the Golden Mile.

Based on these assumptions, Toronto Hydro has adopted the 25 Year Forecast as the load forecast for the entire Scarborough Area for 2030 onwards. The results are provided in Table 10.

Table 10: Post-2031 Forecast for Scarborough Area

Station	Summer LTR (MW)	2030	2034	2039	2044	2049	Year 100% Capacity is Reached
Bermondsey TS	348	88%	93%	99%	101%	102%	2040
Ellesmere TS	189	96%	96%	96%	96%	96%	N/A
Scarboro TS	340	88%	96%	110%	113%	114%	2036
Warden TS	182	97%	105%	117%	121%	122%	2032
Area Non-Coincident %	1059	91%	97%	105%	107%	108%	2036

c. <u>Load Projections – Future Energy Scenarios</u>

The Future Energy Scenarios model considers the long-term impacts that the electrification of heating and transportation, building stock growth, DER integration and other energy transition variables may have on Toronto Hydro's station loading based on six different scenarios.[16] The Future

[16] Exhibit 2B, Section D4, Appendix A – Future Energy Scenarios Overview.

Energy Scenarios incorporates current growth trends, econometric factors, and electrification goals into its modeling, but does not incorporate any GMSDP load. The results from the Future Energy Scenario outlooks are provided in Table 11.

Table 11: FES Projections for Scarborough Area

Station	Summer LTR (MW)	2030	2034	2039	2044	2049	Year 100% Capacity is Reached[17]
Bermondsey TS	348	79-84%	82-89%	84-**95%**	85-**96%**	84-**97%**	N/A
Ellesmere TS	189	101-117%	109-135%	120-154%	128-58%	120-61%	2028-2029
Scarborough TS	340	88-96%	95-107%	100-118%	104-20%	104-23%	2032-2039
Warden TS	182	126-136%	135-151%	140-174%	144-81%	143-86%	2024
Area Non-Coincident %	1059	94-101%	100-111%	104-123%	107-26%	106-29%	2030-2034

Across all scenarios, the Future Energy Scenarios project that all but one station will become highly loaded by 2031, and that the area as a whole will become overloaded between 2030 and 2034. The Future Energy Scenarios reinforces the need for new capacity in the Scarborough Area for the end of the 2025-2029 rate period, and shows that this need may progress much more rapidly than predicted by the Peak Demand Forecast or the Past-2031 Load Projection.

d. Proposed Solution – Scarborough TS Expansion

In order to address both medium- and long-term needs for additional capacity in the Scarborough Area, Toronto Hydro proposes to upgrade the T23 transformer at Scarborough TS, as recommended in the Needs Assessment, and also to install a new DESN at the station. The objective of the expansion is both to provide load relief to existing TSs in the Scarborough Area, and to directly supply the new loads resulting from the GMSDP.

Out of the four stations within Scarborough Area that were analyzed, Scarborough TS was chosen due to the location to the incoming load as well as the station being a central location between

[17] According to the Future Energy Scenarios output only. As a result, this year may be earlier than what is provided in the Peak Demand Forecast.

Bermondsey TS, Ellesmere TS and Warden TS. As a result, the station will be well-placed to offload the other stations in the Area when required.

The Scarborough TS T23 transformer upgrade will provide an estimated 38 MW new capacity to the Scarborough Area by 2028 and will help to relieve short-to-medium term constraints. Following this, the proposed new DESN will provide a further 95 MW to the Area, with the provision to install another 95 MW through a bus expansion when needed in the future. This additional capacity will address medium-to-long term needs.

The scope of work to install the new DESN will be similar to that of the Horner TS expansion completed in the 2020-2024 rate period, and is outlined in the Scarborough TS Bus Expansion subsection of E7.4.4.3 2025-2029 Expenditures - Hydro One Contributions. The in-service date for the new DESN is estimated to be Q4 2030.

Because the forecasted in-service date is beyond the range of the Stations Load Forecast, the effect of Scarborough TS is provided using the using the Post-2031 Forecast and the FES load projections and shown in Figure 6. With the addition of new capacity at Scarborough TS, the Scarborough Area loading is expected to be manageable beyond 2050. FES Projections show that there is a risk of area overloading by 2035, and the magnitude of the potential overloading increases with time. To mitigate the risk of overloading in the long term, Scarborough TSs new DESN will include idle windings to install a second switchgear in the future, when it is required.

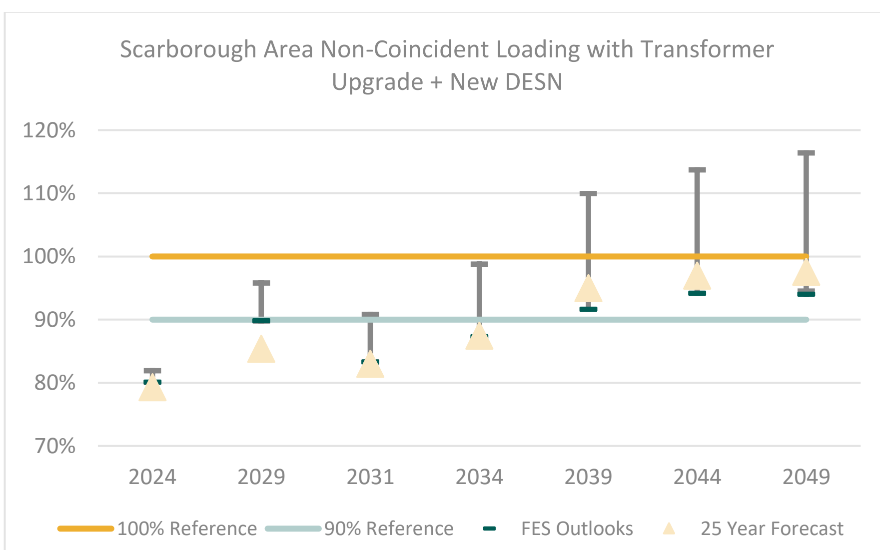

Figure 6: Scarborough Area loading Following Transformer Upgrade and NEW DESN

Toronto Hydro's proposed solution will address the short-term load demand of the Area as well as the medium-to-long term load from GMSDP. Toronto Hydro will continue to monitor the actual and forecasted load of the Area to assess the risk of capacity constraints shortly after the Scarborough TS expansion is completed. If the Area were to become at risk of overloading, Toronto Hydro may install a second switchgear at Scarborough TS to further increase the station capacity by another 95 MW. However, since there is no immediate need for two switchgear and 190 MW of new capacity, the proposed solution includes only one new switchgear and is expected to provide adequate capacity to 2050.

3. Sheppard TS Bus Expansion

The area affected by the Sheppard TS bus expansion consists of: Malvern TS, and Sheppard TS. This area will be called the "Sheppard Area" throughout the rest of this document. The Sheppard Area is shown in Figure 7, and is adjacent to Ellesmere TS (part of the Scarborough Area) which is shown in a dashed line.

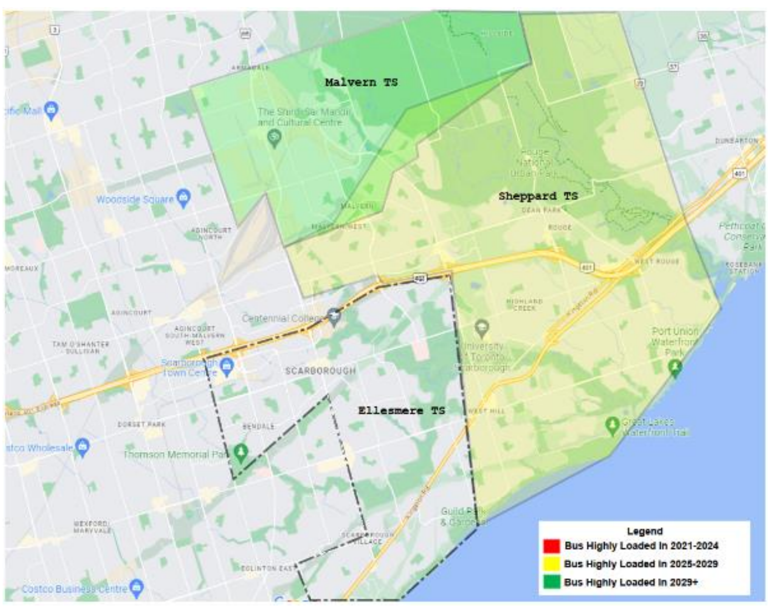

Figure 7 : Service Territories of Stations in the Sheppard Area

Table 12 shows the existing load forecast for the stations in the Sheppard Area based on firm connection requests, as provided in Toronto Hydro's Peak Demand Forecast.

Table 12: Non-Coincident Sheppard Area 10-Yr Load Forecast18

Station	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Malvern TS	176	60%	58%	58%	61%	63%	64%	65%	66%	66%	67%	68%
Sheppard TS	204	77%	81%	82%	85%	86%	87%	89%	89%	90%	91%	92%
Area Non-Coincident %	380	69%	70%	71%	74%	75%	77%	78%	79%	79%	80%	81%

Sheppard TS is forecasted to be highly loaded by 2029, and since the Peak Demand Forecast has been produced, Toronto Hydro has received a new customer request for an additional 20 MW in the Sheppard TS service area. This request will nearly consume the remaining capacity forecasted for Sheppard TS, resulting in a need for load relief. In contrast, Malvern TS is forecasted to have excess capacity.

An additional constraint at Sheppard TS is the lack of short circuit capacity. As discussed in the Generation Protection, Monitoring, and Control Program ("GPMC Program"), short circuit capacity is a requirement to connect new DERs to Toronto Hydro's system. The GPMC Program also states that the available short circuit capacity of the Sheppard TS EZ bus in 2023 is -57.3 MVA, and is forecasted to be -91.4 MVA in 2029. Therefore, in order to ensure that its system does not act as a barrier to new DER connections, Toronto Hydro must relieve both thermal and short circuit capacity constraints at Sheppard TS.

While Malvern TS has spare thermal capacity which can provide load relief to Sheppard TS through load transfers, it is much more challenging and expensive to address short circuit capacity constraints through load transfers.[19] The existing configuration of Sheppard TS also presents a unique opportunity to expand the station for a significantly reduced cost and in a shorter timeframe than comparable expansion projects.[20] This is because the station is already equipped with idle

[18] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.
[19] To provide short circuit capacity through load transfers, specific feeders or sections of feeders connecting large DERs must be transferred. The limited number of large DERs on each feeder makes this a challenging exercise and typically cannot be done in bulk. Furthermore, protection systems for large DERs also need to be transferred over from one station to another and recommissioned, which adds further costs and complexities compared to typical load transfers.
[20] Comparable projects include the Runnymede TS expansion project from the 2015-2019 CIR, the Horner TS expansion project from the 2020-24 CIR, and the newly proposed Scarborough TS expansion project for the 2025-29 CIR.

transformer windings, and as a result, the scope of work would not include transmission or transformation components.

When considering both thermal and short circuit capacity needs, and the significantly reduced cost of expansion presented at Sheppard TS, Toronto Hydro concluded that the expansion of Sheppard TS would present the best value to customers. The expansion of Sheppard TS would involve the installation of a new switchgear, and would provide 95 MW of thermal capacity and an estimated 126 MVA of short circuit capacity.

Sheppard TS is also adjacent to the Scarborough Area, which as discussed in the previous section, is at risk of becoming highly loaded by 2037, despite the expansion of Scarborough TS. As a result, any excess capacity at Sheppard TS may be used to partially manage the long-term loading of the Scarborough Area.

4. <u>Manby TS DESN Reconfigurations</u>

The area affected by the Manby TS DESN Replacements Preparations ("DESN RPs") consists of: Horner TS, Manby TS, and Richview TS. This area will be called the "Manby Area" throughout the rest of this document. The Manby Area is shown in Figure 8.

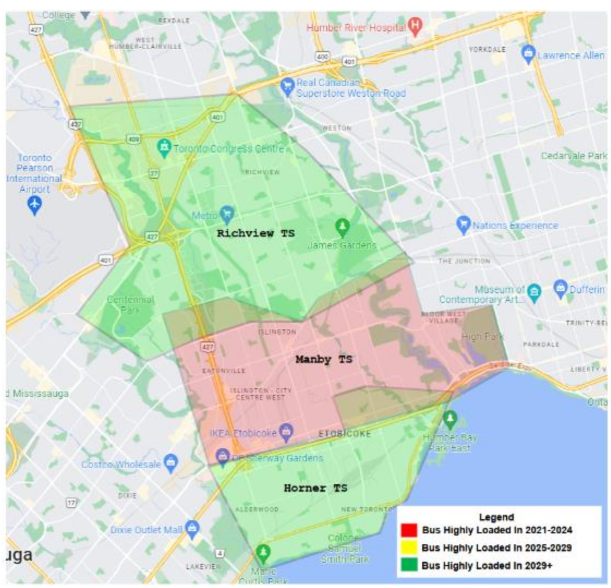

Figure 8 : Service Territories of Stations in the Manby AreaTable 13 shows the existing load forecast for the stations in the Manby Area based on firm connection requests, as provided in Toronto Hydro's Peak Demand Forecast.

Table 13: Non-Coincident Manby Area 10-Yr Load Forecast[21]

STATION	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Horner TS	366	40%	35%	50%	53%	53%	62%	62%	62%	63%	63%	63%
Manby TS	226	109%	89%	91%	99%	99%	87%	89%	90%	92%	94%	96%
Richview TS	460	63%	66%	66%	64%	64%	64%	65%	63%	64%	63%	61%
Area Non-Coincident %	1052	65%	60%	66%	68%	68%	69%	69%	69%	69%	70%	69%

Due to the recent Horner TS expansion completed during the 2020-2024 rate period, the Manby Area is forecasted to have excess capacity to 2031. However, due to forecasted high loading at Manby TS specifically, and given the T13 and T14 transformers require renewal, the Hydro One 2022 Needs Assessment ("NA") Report recommends the upgrade of the Manby TS T13 and T14 transformers to the current standard size of 125 MVA. These upgrades are mentioned in the following Section "Hydro One Transformer Upgrades".

Because of the existing configuration at Manby TS, if the transformer replacements proceed without any reconfiguration of its associated DESN, then the DESN will actually decrease in capacity by 15 MW. Although the new T13 and T14 transformers will be rated at higher capacity, their additional capacity will be locked in idle windings, similar to the current configuration at Sheppard TS. However, the upgrade of the T13 and T14 transformers can provide additional renewal and long-term capacity benefits, if its DESN is reconfigured from the existing Jones configuration to a Bermondsey configuration in coordination with the transformer upgrades.[22][23]

The T3/T4 switchyard at Manby TS will require renewal in the near future. The existing T3/T4 DESN is under-rated which has made managing its load difficult. Rather than replace the T3/T4 switchyard like-for-like and the T13 and T14 transformers life-for-like, Toronto Hydro proposes to upgrade the T13 and T14 transformers (as recommended in the Needs Assessment) and also replace both the existing T13/T14 Jones switchyard and the T3/T4 Jones switchyard with one new Bermondsey

[21] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.
[22] A DESN in Jones configuration is composed of two single-winding transformers and two buses, with one transformer supplying each bus, and a normally-closed bus tie connecting the two buses to one another.
[23] A DESN in Bermondsey configuration is composed of two dual-winding transformers and two buses. One winding from each transformer supplies each bus, and a normally-open bus tie is installed between the buses.

switchyard. The new Bermondsey switchyard will be supplied by the upgraded T13 and T14. In summary, two existing Jones switchyards will be replaced with one new Bermondsey switchyard.

The near-term benefits of this proposal are as follows.

- No loss of capacity for the T13/T14 switchyard;
- Increase in station capacity by +16 MW once both switchyards are replaced;
- Higher reliability replacement plan for the T3/T4 switchyard, rather than replacing the switchyard "in-place" while still supplying customers;
- Fully-rated new Bermondsey switchyard can properly manage the combined load of the existing T3/T4 and T13/T14 DESNs;

In addition, this proposal presents two subsequent long-term options to increase station capacity at Manby TS when needed:

1. When the T3/T4 switchyard is replaced onto the new Bermondsey switchyard, the existing T3/T4 will be left idle in a similar configuration as what currently exists at Sheppard TS. As a result, Toronto Hydro can initiate for a new 60 MW switchyard to be installed using the idle windings, and thereby increase station capacity by 60 MW; or,
2. At the time when the third and last DESN at Manby TS requires renewal, if Toronto Hydro has not pursued the above option, then Toronto Hydro may be able to replace the last DESN and the idle T3/T4 with another new Bermondsey-configured DESN. This would increase the station capacity by approximately 123 MW.

Therefore because of both the near-term and long-term benefits to the renewal and upgrade of Manby TS, Toronto Hydro proposes to replace the existing T3/T4 and T13/T14 switchyards with a new Bermondsey switchyard, in coordination with the T13 and T14 transformer upgrades. This proposal is being referred to as "DESN Reconfigurations".

5. <u>Hydro One Transformer Upgrades</u>

To alleviate capacity constraints, Toronto Hydro proposes to invest in incremental upgrades to Hydro One transformers during the 2025-2029 rate period, as Hydro One completes the renewal of these end-of-life assets. The renewal plans are initiated by Hydro One and included in the Needs Assessment. Because of the coordination with renewal work, these investments present the greatest value-for-money in terms of $/MW, and are pursued even when the incremental capacity may not be immediately accessible.[24]

Based on the most recent Needs Assessment, City of Toronto Development Plans, and electrification risks to station capacity adequacy, Toronto Hydro has identified benefits in upgrading transformers at the stations listed in Table 14 below. These upgrades will immediately provide an estimated 226 MW of new capacity to Toronto Hydro's system, and up to another 272 MW of new capacity with further investments. For similar reasons, the Needs Assessment also recommends the upgrade of these units, with the exception of Carlaw TS.[25]

Hydro One will not plan to replace transformers until the units have reached end-of-life, typically after 45 years.[26] It is cost effective for Toronto Hydro to coordinate upgrades with Hydro One's renewal project schedule. Upgrades are only possible by removing and replacing the existing transformer. The cost to remove and replace the existing unit with a higher capacity unit outside of a Hydro One renewal project is approximately $10 million per unit, less asset depreciation. Alternatively, the incremental cost to upgrade a transformer in coordination with its renewal is approximately $0.8 million. Based on the needs identified from the NA and RIP as shown in Table 4 and Table 5, Toronto Hydro foresees the need for additional capacity at each of the stations in Table **14**. Given the long life of these assets and the cost efficiencies achieved by coordinating with Hydro One's renewal schedule, Toronto Hydro has determined that it is prudent to invest in the incremental transformer upgrades listed in Table 14 to ensure that transformation capacity does not become a bottleneck to station capacity over the long term.

[24] Additional investment(s) may be needed following the transformer upgrade to realize the new capacity. For example, the station switchgear may need to be replaced.
[25] The Carlaw TS T1/T2 transformer renewals are not included the Hydro One NA Report, but their timing for renewal approaches the end of the 2025-2029 CIR rate period. Toronto Hydro proposes to prioritize their replacement and upgrade to support capacity needs identified at the adjacent Basin TS, as noted in the NA and RIP and referenced in Table 5. The East Harbour Master Plan and Port Lands development plans will intensify capacity needs at Basin TS.
[26] Kinectrics "Useful Life of Assets" Report, filed in the EB-2010-0142 application (Exhibit Q1, Tab 2)

Table 14: List of Toronto Hydro Owned Busses Connect to Hydro One Transformer Replacement

Project	Transformer Ratings (MVA)		Immediate New Capacity[27] (MW)	Potential New Capacity[28] (MW)
	Existing	New		
Basin TS – T3/T5 Upgrade	75	100	36	-
Carlaw TS – T1/T2 Upgrade[25]	75	100	54	-
Duplex TS – T1/T2 Upgrade	75	100	-	43
Duplex TS – T3/T4 Upgrade	75	100	-	16
Leslie TS – T1 Upgrade	125	125	-	91
Manby TS – T13/T14 Upgrade	93	125	16	60-122
Scarborough TS – T23 Upgrade	125	125[29]	38	-
Strachan TS – T14 Upgrade	75	100	53	-
Strachan TS – T13/T15 Upgrade	75	100	29	-
Total			**226**	**210-272**

E7.4.4 Expenditure Plan

Spending in the Stations Expansion program over the 2020-2024 rate period was forecasted to be $139.9 million. Toronto Hydro proposes to spend $173.2 million over the 2025-2029 rate period to add 321 MW of new capacity to its system, and contribute to an additional 269 MW of capacity realized in 2030-2034.[30] Forecasted growth, largely driven by City of Toronto Development plans, is driving the need for substantial new capacity to be added to Toronto Hydro's system, resulting in the need for increased expenditures.

[27] New capacity which will be realized following the Hydro One transformer(s) upgrade(s)
[28] Additional investment(s) will be needed following the Hydro One transformer upgrade to realize the new capacity. For example, the station switchgear may need to be replaced, a new switchyard may need to be installed, or an additional transformer may need to be upgraded.
Toronto Hydro replaces end-of-life transformer station switchgear in the Station Renewal program (See Exhibit 2B, Section E6.6 Stations Renewal – Section E6.6.3.1 sub-section 1 TS Switchgear).
[29] Although the Scarborough T23's rating will not change, during the replacement components associated with the unit which limit station capacity will be upgraded, resulting in new capacity.
[30] The Downsview TS and Scarborough TS Expansion projects will contribute 271 MW of new capacity and are forecasted to come in-service during the 2030-2034 rate period.

Table 15: Historical & Forecast Program Costs by Segments ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Copeland TS Expansion	7.5	35.1	26.5	6.3	4.0	-	-	-	-	-
Hydro One Contributions	10.7	15.2	21.0	11.5	2.1	7.8	4.3	29.6	31.8	29.5
Downsview TS	-	-	-	-	-	3.2	3.9	9.6	25.9	27.7
Total	**18.2**	**50.3**	**47.5**	**17.8**	**6.1**	**11.0**	**8.1**	**39.2**	**57.7**	**57.2**

Over the 2020-2024 rate period, Toronto Hydro forecasts to spend $139.9 million in its Stations Expansion Program, which is a small overspend of $8.2 million or 6 percent relative to the $131.7 million forecasted in the 2020-2024 Distribution System Plan.[31]

This variance is mostly attributable to variances in the Hydro One Contributions segment, with a variance of $7.1 million. The major sources of variances in this segment result from: a Copeland TS Phase 1 True-Up payment, switchyard expansions at Bermondsey TS and Richview TS, Hydro One support for a new supply cable between Carlaw TS and Gerrard TS. Each of these sources is included in the Reactive Hydro One Contribution subsegment, which by its nature is challenging to forecast.

The proposed projects in the Stations Expansion program will address capacity constraints in areas identified by the Hydro One's 2022 Needs Assessment ("NA") Report, and will coordinate with the sustainment plans outlined in the Report. Given the complexity and size of these individual projects, these projects entail extensive coordination with Hydro One and other stakeholders (such as contractors, vendors, public etc.), long lead times for ordering equipment, and logistical challenges in heavy electrical equipment delivery. Due to these challenges, the Stations Expansion program is susceptible to fluctuations in spending from year-to-year.

E7.4.4.1 2020-2024 Variance Analysis – Copeland TS Expansion

Copeland TS Phase 2 expansion work commenced in 2017 and is expected to be completed in 2024. Table 16 below provides the cost summary with Actual and Bridge amounts for Phase 2. Over the

[31] Less the Local Demand Response segment, which has moved to the Non-Wires Alternatives Program, Section E7.2

2020-2024 rate period, Toronto Hydro forecasts to spend $79.5 million on Copeland TS Phase 2, which is which is aligned with the $78.4 million forecasted in the 2020-2024 DSP.

Table 16: 2020-2024 Budget (Actual/Bridge/Forecast) Copeland TS – Phase 2 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Copeland TS – Phase 2	7.5	35.1	26.5	6.3	4.0	0	0	0	0	0

An engineering, procurement, and construction (EPC) contractor was selected through a competitive bid process in 2020 and the vast majority of the project costs are incurred in the 2020-2024 rate period. Phase 2 of Copeland TS is expected to complete in early 2024, therefore no expansion cost is forecasted for the period of 2025-2029. Table 17 below summarizes the annual spending on Copeland Phase 2.

Table 17: Copeland Phase 2 Annual Budget Comparison ($ Millions)

Year	Initial Budget (EB-2018-0165)	Current
2017	0.5	0.3
2018	1.8	0.2
2019	7.8	3.5
2020	8.9	7.5
2021	29.7	35.1
2022	38.8	26.5
2023	1.0	6.3
2024	0	4.0
Total	**88.5**	**83.4**

Overall, the total project cost is expected to be $5.1 million below the initial total project cost and the contingency portion of the budget is not utilized. Cost savings arise primarily from more efficient execution and labour expenses, better procurement agreements for major equipment, and experience with execution and incorporation of lessons learned from Copeland Phase 1.

The EPC contractor selection took slightly longer and EPC contractor started work in 2020, whereas it was initially planned in 2019. Thus, the entire schedule and spending profile is shifted later by approximately a year. Costs were lower in 2019 due to planned design work by the EPC contractor starting in 2020 rather than 2019.

In mid-2020, the EPC contractor mobilized to site and pre-construction works and evaluation of existing site conditions was completed. By end of 2020, design progressed to 50 percent and procurement operations commenced. Project management and ancillary costs ramped up in 2020 and continued throughout to the end of the project.

In 2021, project spending was $5.4 million higher than initial plan due to completion of the majority of procurement of major electrical assets slightly ahead of plan. In particular, three Medium Voltage ("MV") Gas-Insulated Switchgears ("GIS"), three MV Air-Insulated Switchgears ("AIS"), High Voltage ("HV") cable, MV cable, and Protection and Control ("P&C") control equipment were delivered to site in 2021. Manufacturing was underway for the three Gas-Insulated Transformers ("GIT") and approximately 47 percent of their costs were incurred by end of 2021. Furthermore, all design was completed (except for 2 percent remaining on mechanical and structural design and a few electrical studies.)

Assembly, installation, testing, and commissioning of the three GIS and three AIS was completed in 2022. In addition, the three GITs were delivered to site from Japan in late 2022. Installation of HV and MV cable, P&C equipment and GITs progressed. Spending in 2022 was $12.3 million lower than initial plan due some procurement work completed earlier in 2021, and electrical equipment construction work continuing into 2023.

Spending in 2023 is $5.3 million higher than initial plan due to construction work continuing into 2023 whereas they were planned to be completed in 2022 in initial version. In particular, assembly, installation, testing, and commissioning of the three GITs and P&C equipment continued into 2023. Energization of major electrical equipment, including all three GITs, will be carried out in 2023.

Full system integration testing will commence near the end of 2023 and continue into 2024. Project closeout, site restoration and final site landscaping works is expected to be completed in early 2024.

2020-2024 Variance Analysis – Hydro One Contributions

Table 18 below provides the 2020-2024 variances for each project requiring Hydro One Contributions, as compared to the 2020-2024 DSP. Toronto Hydro forecasts an overspending of $7.1 million relative to the $53.3 million forecasted in the 2020-2024 DSP.

Table 18: Hydro One Contributions 2020-2024 Variances ($ Millions)

Subsegments	2020-2024 Planned	2020-2024 Actual/Forecast Cost	Variance
Horner Expansion	34.4	29.2	-5.2
Hydro One Transformer Upgrades	3.1	6.3	+3.2
Finch TS B-Y Bus Replacement	4.1	0	-4.1
Reactive Hydro One Contribution and True-Up Costs	11.7	24.9	+13.2
Total	**53.3**	**60.4**	**+7.1**

1. **Horner TS Expansion**

In the 2020-2024 rate application, Toronto Hydro forecasted a $34.4 million capital contribution to Hydro One for the Horner TS expansion based on a Class C estimate provided by Hydro One at the time. The actual costs incurred over 2020-2024 was $29.2 M, but a true-up payment may be required in the 2025-2029 rate period.

2. **Hydro One Transformer Upgrades:**

Over the 2020-2024 rate period, Toronto Hydro forecasts to contribute $6.3 million to Hydro One to upgrade existing Hydro One-owned power transformers. This will result in an overspend of $3.2 million compared to the forecast of $3.1 million in the 2020-2024 rate application. The projects are driven by Hydro One sustainment plans and new customer connections. Major sources of variance are as follows.

- **Carry-over transformer upgrades from the 2015-2019 rate period:** additional $2.7 million for lagging payments or to complete work initially forecasted to be complete by 2019, at Cecil TS, Dufferin TS, and Main TS.

- **Additional transformer upgrades:** additional $1.8 million capital contribution to Hydro One to upgrade transformers at Bridgman TS and Strachan TS, which was not included in the 2020-2024 DSP due to the timing of Hydro One's sustainment plans.
- **Variances to costs of proposed projects:** less $1.5 million capital contribution to Hydro One for planned transformer upgrades at Charles TS, Duplex TS, and Windsor TS. Hydro One is forecasted to charge an additional $1 million for the Charles TS transformers, the Duplex TS transformers have been deferred to the 2025-29 rate period, and Hydro One did not charge to upgrade the transformers at Windsor TS due to downsizing other equipment.

3. Finch TS B-Y Replacement

In the 2020-2024 rate application, Toronto Hydro proposed to replace Finch BY bus in coordination with Hydro One for a contribution of $4.1 million; however, Hydro One deferred the BY replacement to beyond 2025. To address a progressing failure risk, Toronto Hydro decided to replace the end-of-life circuit breakers and disconnect switches on the BY bus instead of waiting for the entire BY bus to be replaced.[32] Therefore, by pursing this alternative through the Stations Renewal Program, this Hydro One Contribution was never made and resulted in a variance of -$4.1 million.

4. Reactive Hydro One Contribution and True-Up Costs:

In the 2020-2024 rate application, Toronto Hydro allocated $11.7 million for reactive Hydro One contributions to support expansion projects or true-up costs unforeseen at the time of the application. Toronto Hydro forecasts to contribute $24.9 million over the 2020-2024 rate period for these reasons, resulting in an overspend of $13.2 million.

Pursuant to applicable cost recovery agreements (including criteria regarding cost reconciliation review), Toronto Hydro incurred $9.9 million to reconcile past Hydro One capital contributions to Copeland TS Phase 1. Such reconciliations are typically based on actual asset or station loading and project in-service anniversaries, making the costs difficult to forecast in advance. In particular for this project, $5.7 million was incurred due to reduced station loading, and $4.2 million was incurred due to additional spend by Hydro One relative to their CCRA estimate.[33]

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[32] Please refer to the Stations Renewal Program Section E6.6.4.1 "TS Segment Expenditure Plan", subsection "TS Outdoor Breaker – 2020-2024 Variance Analysis".
[33] Connection Cost Recovery Agreement

Toronto Hydro forecasts to contribute $10.9 million to Hydro One for the following expansion projects which could not be estimated at the time of the previous application.

- **Switchyard expansions at Bermondsey TS and Richview TS:** These projects will expand the switchyards at the respective stations by six and four circuit breakers, permitting new feeders to access stranded station capacity. A forecasted $8.5 million capital contribution is required.
- **New supply cable between Carlaw TS and Gerrard TS:** This project will increase the capacity of Carlaw TS by 20 MVA and resulted in a Hydro One contribution of $2.4 million.

Finally, Toronto Hydro has allocated a remaining $1.9 million in 2024 for additional unforeseen Hydro One Reactive contributions, in the form of cost variances from current forecasts.

E7.4.4.2 2025-2029 Expenditures - Downsview TS

Toronto Hydro forecasts to spend $70.2 million on Downsview TS during the Planning and Preparation stage over the 2025-2029 rate period, and expects to spend another $70 million over the Construction and Energization stage over the 2030-2034 rate period. Downsview TS is expected to complete in late 2033. An annual breakdown of the expenditures is shown below in Table 19.

Table 19: 2025-2029 Budget Downsview TS ($ Millions)

	Forecast – Planning and Preparation					Forecast – Construction & Energization				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Downsview TS	3.2	3.9	9.6	25.9	27.7	30.7	24.0	7.6	7.7	--

1. Downsview TS – Planning and Preparation

The Downsview TS project will be a large and complex project for Toronto Hydro, with only the Copeland TS project being comparable.

The Planning and Preparation stage will involve the portion of work completed in the 2025-2029 rate period, which will involve the: procurement and preparation of a new site, installation of 230 kV station assets, new building construction, and partial work on remaining station assets. The expenditures for this scope are forecasted to total $70.2 million over the period with $14.6 million included in the rate base when civil assets are completed. The remaining forecasted spend is related to electrical assets which will be energized when the station is completed in 2033, and will not be included in the rate base until such time.

There are four major activities to be completed in the 2025-2029 rate period: contractor Request for Proposal ("RFP"), design and engineering, major asset procurement, and construction or installation of some major assets.

A summary of the Downsview TS – Planning and Preparation stage schedule and annual cost is provided below in Table 20: Summary Schedule and Annual Cost of Downsview TS – .

Table 20: Summary Schedule and Annual Cost of Downsview TS – Planning and Preparation

Year	Budget ($ Millions)	Work Schedule
2025	3.2	• Partial Property Acquisition and Site Preparation
2026	3.9	• Completion of Property Acquisition and Site Preparation • Design of 230 kV bus work and disconnect switches
2027	9.6	• Procurement of 230 kV bus work and disconnect switches • Design of 230 kV circuit breakers and procurement • Design of 230 kV underground circuits and supporting civil structures • Design of switchgear building • Procurement of construction equipment and materials for new building
2028	25.9	• Installation of 230 kV bus work and disconnect switches • Partial installation of 230 kV circuit breakers and foundations • Partial construction of civil structures for 230 kV underground circuits • Partial construction of switchgear building • Partial design of power transformers, foundations, fire walls, fire suppression, and oil containment systems

Year	Budget ($ Millions)	Work Schedule
2029	27.7	• Completed installation of 230 kV circuit breakers and foundations • Continued construction of civil structures for 230 kV underground circuits, and partial procurement of 230 kV circuits and protection systems • Completed construction of switchgear building • Completed design for power transformers and supporting assets • Partial procurement of first power transformer • Procurement of materials for power transformer foundations and oil containment systems • Design and partial procurement of 27.6 kV switchgear • Design and partial procurement of station AC, DC, and ancillary services

2. <u>Downsview TS – Construction and Energization</u>

The Construction and Energization stage will involve work completed starting in 2030 until commissioning of the new station in 2033. Work in this stage will involve the: completion of 230 kV underground circuits, installation of power transformers, installation of switchgear, installation of station services, and overall commissioning. The expenditures for this scope are estimated to total $70 million over the period.

A summary of the Downsview TS – Construction and Energization stage schedule and annual cost is provided below in Table 21.

Table 21: Summary Schedule and Annual Cost of Downsview TS Construction and Energization Stage

Year	Budget ($ Millions)	Work Schedule
2030	30.7	• Completed construction of civil structures for 230 kV underground circuits • Completed procurement of 230 kV circuits and protection systems • Partial installation of 230 kV circuits and protection systems

Year	Budget ($ Millions)	Work Schedule
		• Installation of foundations and oil containment systems of power transformers • Partial procurement of first and second power transformers • Delivery of 27.6 kV switchgear • Completed procurement and partial installation of station AC, DC, and ancillary services
2031	24.0	• Completed installation of 230 kV circuits and protection systems • Delivery and installation of first power transformer • Partial procurement of second power transformer • Installation of fire wall between first and second transformer • Partial installation of 27.6 kV switchgear • Completed installation of station AC, DC, and ancillary services
2032	7.6	• Delivery and installation of second power transformer • Completed installation of 27.6 kV switchgear
2033	7.7	• Installation of fire suppression systems for power transformers • Final commissioning of power transformers, 27.6 kV switchgear, and integrated protection systems with Hydro One

E7.4.4.3 2025-2029 Expenditures - Hydro One Contributions

Toronto Hydro forecasts to spend $103.0 million on Hydro One capital contributions over the 2025-2029 rate period. The expenditures include contributions to Hydro One for stations expansions and for transformer upgrades. These projects are planned based on the Needs Assessment (see below at Section 7.4.7 Regional Planning Needs). Additionally, contributions towards the Hydro One-owned Downsview SS are included.

Table 22: 2020-2029 Budget (Actual/Bridge/Forecast): Hydro One Contribution ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Horner TS Expansion	8.5	5.0	15.7	--	--	--	--	--	--	--
Finch TS B-Y Bus Replacement	--	--	--	--	--	--	--	--	--	--
Downsview SS	--	--	--	--	--	--	0.6	1.7	2.9	0.6
Scarborough TS Expansion	--	--	--	--	--	--	0.3	17.0	17.0	17.0
Sheppard TS Bus Expansion	--	--	--	--	--	--	0.5	4.5	5.0	5.0
Manby TS DESN Reconfigurations	--	--	--	--	--	--	0.5	3.5	4.0	4.0
Hydro One Transformer Upgrades	1.1	--	2.5	2.5	0.2	4.3	0.4	1.6	1.6	1.6
Reactive Hydro One Contributions & True-Up Costs	1.1	10.1	2.5	9.0	1.9	3.5	2.0	1.3	1.3	1.3
Total	**10.7**	**15.1**	**21.0**	**11.5**	**2.1**	**7.8**	**4.3**	**29.6**	**31.8**	**29.5**

1. Hydro One Switching Station for Downsview TS

Based on high level estimates from Hydro One, Toronto Hydro forecasts to contribute $5.8 million over the 2025-2029 rate period to Hydro One as an initial contribution towards Hydro One's Downsview Switching Station ("Downsview SS"). Downsview SS is expected to be largely constructed during the 2030-2034 period. As a result, Toronto Hydro is only forecasting expenses over the 2025-2029 rate period to be associated with the procurement of land for and the site preparation of the new SS.

Table 23: Downsview TS Expansion Hydro One Payment Breakdown

Project	Expenditures ($ Millions)	Payment Year
Downsview SS	0.0	2025
	0.6	2026
	1.7	2027
	2.9	2028
	0.6	2029

2. Scarborough TS Expansion

In order to install a new DESN at Scarborough TS, Toronto Hydro forecasts to contribute $51.3 million to Hydro One over the 2025-2029 rate period. Toronto Hydro estimates the project to be completed in 2030, and therefore forecasts and additional contribution of $5.0 million in 2030. As a result, none of the 2025-2029 spending will be included in the rate base until the project is completed in 2030. In total, Toronto Hydro forecasts the project to cost $56.3 million in capital contributions. The forecasted annual expenditures are provided in Table 24 below.

Because this project is still in its early stages, Hydro One has not been able to provide Toronto Hydro with a cost estimate at the time of this Filing. However, from the high-level perspective, the scope of work of this project is the same as the Horner TS expansion completed during the 2020-2024 rate period, less half of its switchyard[34]. As a result, Toronto Hydro has forecasted the expenditures of this project based off of the actual expenditures of the Horner TS expansion project, less the estimated costs for half of the switchyard.

The scope of work involved for this project includes: the clearing of land and site preparation for the new DESN, the installation of new transmission taps and high voltage disconnect switches, the installation of two new 125 MVA transformers, the installation of a new 95 MW switchyard with six circuit breakers, and the installation of a new P&C building.

Table 24: Scarborough TS Expansion Hydro One Payment Breakdown

Project	Expenditures ($ Millions)	Payment Year
Scarborough TS Expansion	0	2025
	0.3	2026
	17.0	2027
	17.0	2028
	17.0	2029
	5.0	2030

[34] The Horner TS expansion provided 12 new circuit breakers, whereas the Scarborough TS expansion proposes 6 new circuit breakers. The assets upstream of the circuit breakers (such as transformers) are proposed to be the same for both projects.

3. Sheppard TS Bus Expansion

In order to install a new bus at Sheppard TS, Toronto Hydro forecasts to contribute $15.0 million to Hydro One over the 2025-2029 rate period. The forecasted annual expenditures are provided in Table 25 below.

Because this project is still in its early stages, Hydro One has not been able to provide Toronto Hydro with a cost estimate at the time of this filing. However, Toronto Hydro has estimated expenditures based on the scope of work, which is similar to its TS switchgear installations from its Stations Renewal Program and from its Copeland Phase 1 and Phase 2 expansion projects.

The scope of work includes the installation of a new gas-insulated switchgear (GIS) comprised of six feeder circuit breakers, three padmounted feeder-tie disconnect switches, P&C devices, and a new building to house the GIS and P&C devices.

Table 25: Sheppard TS Bus Expansion Hydro One Payment Breakdown

Project	Expenditures ($ Millions)	Payment Year
Sheppard TS Bus Expansion	0	2025
	0.5	2026
	4.5	2027
	5.0	2028
	5.0	2029

4. Manby TS DESN Reconfigurations

In order to replace two Jones switchyards with one Bermondsey switchyard at Manby TS, for both capacity and renewal benefits, Toronto Hydro forecasts to contribute $12.0 million to Hydro One over the 2025-2029 rate period. The forecasted annual expenditures are provided in Table 26 below.

This project is still in its planning phase with Hydro One, due to the need to coordinate with and adapt Hydro One's existing T13/T14 transformer upgrade plans, which they have proposed for 2030. Because the T13/T14 upgrade is planned to take place seven years into the future from the time of this filing, Hydro One has not been able to develop a scope of work at this time. Similarly, Hydro One also has not been able to provide Toronto Hydro with a cost estimate at the time of this filing.

As a result, Toronto Hydro has estimated the scope of work involved, and has used this to estimate the needed Hydro One contributions. Consequently, there is more uncertainty in this expenditure forecast compared to the other projects proposed in this Program.

However, Toronto Hydro will need to provide its capital contribution to Hydro One during the 2025-2029 rate period, and that the capital contribution for this project will be too substantial to be managed by the Reactive Hydro One Contributions subsegment. Therefore, Toronto Hydro has elected to budget for this project separately, and has produced the best expenditure forecast it can with the information available at this time.

Table 26: Manby TS DESN Reconfigurations Hydro One Payment Breakdown

Project	Expenditures ($ Millions)	Payment Year
Manby TS DESN Reconfigurations	0	2025
	0.5	2026
	3.5	2027
	4.0	2028
	4.0	2029

5. Hydro One Transformer Upgrades

Toronto Hydro forecasts to contribute $9.5 million to Hydro One over the 2025-2029 rate period, in order to upgrade certain end-of-life transformers during their natural renewal projects. Table 27 below outlines the contributions to Hydro One by project, and the year the contribution is expected to be made.

The cost for each project was forecasted based on the actual costs of transformer upgrade projects completed or in-progress over the 2020-2024 rate period. The timing of each project has been provided in the NA assessment, which has been used to forecast when each capital contribution will be required, based on historical timing trends.

Table 27: Hydro One Transformer Upgrades Payment Breakdown

Hydro One Transformer Upgrades	Expenditures ($ Millions)	Payment Year
Basin TS – T3/T5	1.6	2025
Carlaw TS – T1/T2	1.6	2029
Duplex TS – T1/T2	1.6	2025

Hydro One Transformer Upgrades	Expenditures ($ Millions)	Payment Year
Duplex TS – T3/T4	1.6	2028
Leslie TS – T1	0.3	2025
Scarborough TS – T23	0.4	2026
Strachan TS – T14	0.8	2025
Strachan TS – T13/T15	1.6	2027

6. Reactive Hydro One Contributions

As noted in Section 0, **2020-2024 Variance Analysis – Hydro One Contributions**, Toronto Hydro forecasts to contribute $24.9 million over the 2020-2024 rate period towards Reactive Hydro One Contributions. This subsegment was first introduced during the 2020-2024 CIR based on previous experience of funding shortfalls as new, unbudgeted, Hydro One projects were initiated, or as unexpected Hydro One true-up costs were billed to Toronto Hydro. Examples of such Hydro One projects include transformer or cables upgrades, or the installation of new circuit breakers, which result in an incremental increase in capacity.

As predicted, there were indeed significant unexpected projects and true-up costs which developed during the 2020-2024 rate period, and the Reactive Hydro One Contributions subsegment is forecasted to mitigate (approximately half of) the unexpected spending in the Hydro One Contributions segment, as intended. Therefore, Toronto Hydro proposes this subsegment continue into the 2025-2029 rate period, as a continued mitigation measure since it again anticipates a need in the 2025-2029 rate period.

To this end, Toronto Hydro has allocated $9.4 million over the 2025-2029 rate period towards Reactive Hydro One Contributions. The annual expenditures are provided in Table 28 below.

Table 28 : Reactive Hydro One Contributions Annual Allocations

Subsegment	Expenditures ($ Millions)	Payment Year
Reactive Hydro One Contributions	3.5	2025
	2.0	2026
	1.3	2027
	1.3	2028
	1.3	2029

E7.4.5 Options Analysis

Toronto Hydro has identified and evaluated various options to address system needs, as outlined in the below sections.

E7.4.5.1 Options Comparison for the Downsview Area

To address the forecasted need for additional capacity in the Downsview area, Toronto Hydro considered several options including: Status Quo, Load Transfers, NWSs, Station Upgrades, New DESN(s), and a new Downsview TS. The key results of the Options studied are summarized in Table 29. Options were considered in order of increasing level of intervention, until an acceptable option was identified. Option 6 – building the new Downsview TS is the only option capable of meeting system needs with reasonable risks and quantity of load transfers. See Exhibit 2B, Section E7.4, Appendix A – Downsview Business Case for further details of the assessment of these options.

The options were assessed as follows:

- **Option 1 – Status Quo** was rejected. Status quo is never recommended when capacity constraints are identified, but this option illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress.
- **Option 2 – Load Transfers** was also rejected as it is only viable up until 2029.
- **Option 3 – NWSs** was rejected because it would not provide a long-term solution and had a very high execution risk. NWSs are designed to address short-to-medium term capacity constraints. The quantity of load that needs to be addressed is at a magnitude well in excess of levels achieved and planned to date (e.g. 10 MWs achieved and 30 MW planed compared to a need for 193 MW).[35]
- **Option 4 – Station Upgrades** was considered, but all station equipment in the Downsview Area is already sized to maximum ratings and cannot be further upgraded. Therefore, this option is technically infeasible and was rejected.

[35] See E7.2.1.4

- **Option 5 – New DESN(s)** was considered for each of the four existing stations within the Downsview Area; but only Finch TS could accommodate a new DESN. Although possible, a new DESN at Finch TS would be especially difficult to utilize effectively in the Downsview Area, due to: existing congestion, geographic barriers, and distance from the DASP area. These challenges translate into high execution risks, an expectation of stranded capacity at Finch TS (inaccessible to the rest of the Downsview Area), and an expectation for higher than typical load transfer costs. Finally, because Finch TS is remote from the DASP area and is not central to the broader Downsview Area, this Option is forecasted to require a high quantity of load transfers, specifically 290 MW by 2044, to redistribute the new capacity across the Downsview Area. As a result of the many significant risks, challenges, and inefficiencies presented by Option 5, this Option was ultimately rejected.

- **Option 6 – Construction of Downsview TS** is the selected option. Because of the proposed placement of the new TS, it is suited to offload existing stations and directly supply the new DASP loads, which is the major driver of load growth in the broader Downsview Area. This results in a minimal execution risk in terms of addressing system needs once the new TS is in service. The construction of a new TS is a large and complex undertaking. Therefore, overall execution risk was evaluated as Medium. Because of the designed placement of the new TS, the required load transfers of this Option are less than in the previous Option 5 at 252 MW. Option 6 also includes a provision to address the risk of subsequent overloading in the long term by permitting a second DESN to be installed at the newly constructed TS, whereas no provision exists in Option 5.

1 **Table 29: Summary of Options Outcomes for the Downsview Area**

Option (Increasing in Level of Intervention)	Decision	Reason for Decision	Decision Criteria				
			Acceptable Solution Outside of Short Term	Cumulative Load Transfers or NWSs Required [by 2044 or Earlier] (MW)[36]	Operational + Customer Connection Risks	Execution Risk	Risk of Subsequent Overloading
1 – Status Quo	Reject	This Option only provides a short-term solution.	No	N/A – viable only in short term	High	Medium	Forecasted Overload
2 – Load Transfers	Reject	This Option can only manage loading until 2029.	No	N/A – viable only in short term	Low	Minimal	Forecasted Overload
3 – NWSs	Reject	NWSs are not designed to be long term solutions. Very high execution risk due to unprecedented quantity of NWSs needed.	No	193	High	Very High	Mitigated
4 – Station Upgrades	Reject	Technically infeasible: Station equipment is already sized to maximum ratings.	No	N/A	N/A	N/A	N/A
5 – New DESN(s)	Reject	High execution risks, likelihood of stranded capacity, and excessive quantity of load transfers drive the need for an alternative solution.	Yes	290	Minimal	High	Unmitigated
6 – New TS	**Accept**	Meets system needs with reasonable risks.	Yes	252	Minimal	Medium	Mitigated

2

[36] Load relief (as load transfers or NWAs) required past 2044 is not considered in this Options Comparison, since the Downsview Area is forecasted to exceed 90% loading again in 2044, given Options 5 or 6. At that point, additional new capacity may be considered rather than additional load transfers or NWAs.

E7.4.5.2 Options Comparison for the Scarborough Area

To address the forecasted need for additional capacity in the Scarborough Area, Toronto Hydro considered several options including: Status Quo, Load Transfers, NWSs, Station Upgrades, New DESN(s), and a new TS. The key results of the Options studied are summarized in Table 30. Options were considered in order of increasing level of intervention, until an acceptable option was identified. Option 5 – constructing a new DESN at Scarborough TS is the option capable of meeting system needs with the least cost and risk. See Exhibit 2B, Section E7.4, Appendix B – Scarborough TS Business Case for further details of the assessment of these options.

The options were assessed as follows:

- **Option 1 – Status Quo** was rejected. The status quo is never recommended when capacity constraints are identified, but this option illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress.
- **Option 2 – Load Transfers** was also rejected as it is only viable up until 2029.
- **Option 3 – NWSs** were rejected because they would not provide a long-term solution and had a very high execution risk. NWSs are designed to address short-to-medium term capacity constraints. The quantity of load that needs to be addressed is at a magnitude well in excess of levels achieved and planned to date (e.g. 10 MWs achieved and 30 MW planed compared to a need for 179 MW).[37]
- **Option 4 – Station Upgrades** were also rejected as they are only viable up until 2030.
- **Option 5 – New DESN(s)** considered constructing a new DESN at either Scarborough TS or Warden TS, in addition to investing in a transformer upgrade at Scarborough TS which was considered in Option 4. This Option will address capacity needs into the long term, and has a substantially lower cost and risks compared to Option 6. Therefore, this Option was selected as the preferred Option.
- **Option 6 considered constructing a new TS** in the Scarborough Area to provide new capacity. However, this Option provides the same quantity of capacity as Option 6, but requires a

[37] see E7.2.1.4

much higher cost, and a much higher execution risk and lead time. As a result, Option 6 was rejected.

Due to the challenges in geography in expanding Warden TS and increased reliability risks, Toronto Hydro selected Scarborough TS as the station to expand at this time.

1 **Table 30: Summary of Options Outcomes for Scarborough Area**

Option (Increasing in Level of Intervention)	Decision	Reason for Decision	Decision Criteria				
			Acceptable Solution Outside of Short Term	Cumulative Load Transfers or NWSs Required [by 2039 or Earlier] (MW)[38]	Operational + Customer Connection Risks	Execution Risk	Risk of Subsequent Overloading
1 – Status Quo	Reject	This Option is only viable as a short-term interim solution while a long term solution is in progress.	No	N/A – viable only in short term	High	Medium	Forecasted Overload
2 – Load Transfers	Reject	This Option can only manage loading until 2029.	No	N/A – viable only in short term	Low	Minimal	Forecasted Overload
3 – NWSs	Reject	NWSs are not designed to be long term solutions. Very high execution risk due to unprecedented quantity of NWSs needed.	No	179	High	Very High	Mitigated
4 – Station Upgrades	Reject	This Option can only manage loading until 2030.	No	30	Minimal	Minimal	Forecasted Overload
5 – New DESN(s)	**Accept**	Meets system needs with reasonable risks and quantity of load transfers.	Yes	63	Minimal	Medium	Mitigated
6 – New TS	Reject	This Option carries excessive costs, lead time, and risks in comparison to Option 5.	Yes	68	Minimal	High	Mitigated

2

[38] Load relief (as load transfers or NWAs) required past 2039 is not considered in this Options Comparison, since the Downsview Area is forecasted to exceed 90% loading again in 2036, given Options 5 or 6. At that point, additional new capacity may be considered rather than additional load transfers or NWAs.

E7.4.5.3 Options for the Sheppard Area

In addition to the proposed option to address needs in the Sheppard TS Area, to install a new bus at Sheppard TS, two alternative options were considered: load transfers, and non-wires alternatives (NWAs). Although the proposed option is the most expensive in the short term, it provides additional benefits that the alternatives cannot realize, as summarized in

Table 31 below. Most critically, the proposed option is the only option which also provides new short circuit capacity to enable new DERs at the constrained Sheppard TS.

To keep consistent with the E7.2 Non-Wires Alternatives Program, the same high-level unit cost for load transfers is provided in

Table 31. However, as discussed in E7.4.3 Drivers and Need, it is very challenging to practically address short circuit capacity constraints through load transfers, which is why this option has not been traditionally utilized at present. In practise, the cost to complete such load transfers is expected to exceed the high-level unit cost provided, which was based on projects completed to relieve thermal capacity constraints.

Additionally, upon consideration of the FES, Toronto Hydro has reason to believe that the Sheppard TS bus expansion may in fact be the lowest-cost option in the long term. This is because, when using the provided high-level unit cost, the load transfer option results in an equal cost when a cumulative 50 MW of load has been transferred away from Sheppard TS. Five of the six FES project that this cumulative amount of load will have been transferred by 2033-2039, depending on the scenario.

In contrast to load transfers, Non-Wire Solutions (“NWS”) can also be considered as an alternative to the proposed option. However, unlike load transfers, NWSs bear an annual cost, and therefore are best used as a short-term solution. In particular, for the same quantity of MW addressed, the cost of the NWSs solution becomes equal to the load transfer solution after 4 years have passed, based on the high-level unit cost provided. Therefore, in the long term, the NWSs option is expected to be even more expensive than the load transfer option.

In summary, for the reasons of the additional benefits (particularly to enable new DER connections), and because of the expectation to be the lowest cost option in the long term, the Sheppard TS bus expansion was selected as the preferred option.

Table 31: Benefits Presented by Options to Address Sheppard Area Needs

Benefit or Cost	Sheppard TS Bus Expansion	Load Transfers	NWAs
New Thermal Capacity (MW)	95	0	0
New Short Circuit Capacity (MVA)	126	0	0
Can Provide Support to Scarborough Area?	Yes	No	No
Cost ($M)[39]	15.0	0.3/MW	0.075/ MW-year

E7.4.5.4 Options for the Manby TS Area

The proposed Manby TS DESN reconfigurations project is being triggered by Hydro One's planned renewal and upgrade of its T13/T14 transformers as stated in the Needs Assessment, and by the upcoming need to renew the T3/T4 switchyard. As a result, there are only two options to consider are to either take advantage of the renewal opportunity to improve the station (as proposed), or to dismiss this opportunity.

For similar financial reasons as discussed with the Hydro One Transformer Upgrades subsegment in E7.4.3 Drivers and Need, if Toronto Hydro does not take the opportunity to improve the station during the upcoming renewal work, it will likely have to wait another 45 years before it has another opportunity to complete the proposed improvements or undertake upgrades at a significantly higher cost.

As discussed in the Manby TS DESN Reconfigurations subsection of E7.4.3 Drivers and Need, the proposed option has multiple short term and long-term benefits, related to capacity, reliability, and the execution of the renewal of Manby TS. Ultimately, this option will permit up to 139 MW of new capacity to be added in the long term. These benefits will be lost if the proposed DESN reconfigurations do not proceed.

Upon consideration of the FES, Toronto Hydro believes it is prudent to enable options to increase the capacity of Manby TS in the long term. Four of the six FES project that the Area will require additional capacity between 2035-2039. With the Horner TS expansion complete in the 2020-2024

[39] High-level unit cost estimates for load transfers and NWAs were taken to be consistent with those presented in E7.2 Non-Wires Alternatives Program

rate period, there are presently no expansion options available in the Area other than the installation of a new TS, which was considered as the alternative to the Horner TS expansion.

To align with an investment philosophy of a least-regrets approach, Toronto Hydro should not dismiss the limited-time opportunity to enable Manby TS to be expanded in the future, when needed. In order to do this, Toronto Hydro must invest in the proposed Manby TS DESN reconfigurations project in coordination with Hydro One's T13/T14 transformer renewal project.

For this reason, and because of the other benefits discussed in E7.4.3 Drivers and Need, the proposed option was selected over the alternatives.

E7.4.6 Execution Risks & Mitigation

E7.4.6.1 Downsview TS

The Downsview TS segment is a large undertaking and involves multiple execution risks, which include:

- Given the complex nature of these projects, a host of inherent planning challenges and risks can impact overall project cost and execution, such as the length of time required to acquire permits;
- New Downsview TS site location and land purchase;
- Road moratoriums established by the City of Toronto;
- 230 kV U/G cable design and construction and Hydro One 230kV switching station design and construction – potential timeline issues;
- Engage Hydro One 230kV Switching Station Design and Construction;
- Logistical challenges in delivering electrical equipment into the city; and
- Coordination with distribution planners as well as with third parties.

Toronto Hydro will communicate key lessons learned from past projects to Downsview TS bidders during the RFP procurement process to mitigate project execution risks. In particular, Toronto Hydro will provide risk information associated with facility conditions and restrictions, logistical and transportation issues, unique specifications of major electrical equipment, and permitting issues. Coordination with Hydro One for switching station construction, the city new TS land and association on the new 230kV route will be the risks on the new TS's construction timeline.

Financial risks will be mitigated by pursuing a fixed-price, turn-key, EPC contract. A competitive bid process will result in a selection of one general contractor responsible for all the major tasks. This is expected to be completed in 2026.

Quality control risks will be mitigated via the use of reputable third-party firms with extensive electrical station construction experience to carry out verification and payment review/billing certification. A consulting engineering firm will be utilized to investigate and resolve emerging site issues and ensure that construction is carried out according to specifications.

E7.4.6.2 Hydro One Contribution

The following risks are associated with the execution of Hydro One contribution project:

- Schedule depends on Hydro One's ability to execute the work;
- Overall project cost is highly dependent on Hydro One estimates; and
- Additional tasks (such as installation of bus and feeder ties or other safeguard measures to protect Toronto Hydro assets during Hydro One asset replacement) may be identified during detailed equipment outage planning. If an identified task is performed by Toronto Hydro, it will increase the project's cost for Toronto Hydro.

To mitigate these risks, Toronto Hydro engages in active coordination with Hydro One through bi-monthly meetings and as-required on-site meetings with relevant stakeholders to remain aligned with Hydro One's latest sustainment plans.

E7.4.7 Regional Planning Needs

The following Table 32, Table 33, and Table 34 (from the IRRP Needs Assessment Report), highlight the emerging needs that have been identified in the Toronto Region since the previous regional planning cycle, and reaffirms the near, medium, and long-term needs already identified in the previous RIP.[40] The tables below also highlight how the Stations Expansion program is expected to address these needs.

[40] See Exhibit 2B, Section B, Appendix A, B, C, D, and E for Regional Planning Reports.

1 **Table 32: New Needs Identified in the Needs Assessment**

New Needs	Needs Assessment Section	Stations Expansion Program
End-of-Life (EOL) Assets	*7.1*	See E7.4.3.2, Section 2. – Hydro One Transformer Upgrades.
East Harbor / Port Lands Area and Basin TS – Transformation Capacity	*7.1.4*	Needs Assessment identified this need by long term planning, short term by replacing T3/5 with 100 MVA.

2 **Table 33: Needs Identified in Previous RIP**

Needs Identified in Previous RIP	Needs Assessment Section	RIP Report Section	Stations Expansion Program
South-West Toronto – Station Capacity	7.2.1	7.2	Addressed with Horner expansion in 2020-2024 Stations Expansion plan.
Downtown District – Station Capacity	7.2.2	7.3	Addressed with Copeland TS - Phase 2 expansion in 2020-2024 Stations Expansion plan.
230 kV Richview x Manby Corridor – Line Capacity	7.2.3	7.4	Transmission network constraint. Not applicable to Toronto Hydro.
Supply Security – Breaker Failure at Manby West & East TS	7.2.4	7.6	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Leaside Autotransformer – Transformation Capacity	7.2.5	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
Voltage Instability of 115 kV Leaside Subsystem	7.2.5	Identified in Central Toronto Area IRRP report – Appendix E	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Leaside x Wiltshire Corridor – Line Capacity	7.2.6	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Manby Autotransformers – Transformation Capacity	4.2.7	7.10	Transmission network constraint. Not applicable to Toronto Hydro.

Needs Identified in Previous RIP	Needs Assessment Section	RIP Report Section	Stations Expansion Program
115 kV Manby West x Riverside Junction – Line Capacity	7.2.8	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Don Fleet JCT x Esplanade TS – Line Capacity	7.2.9	Identified in Central Toronto Area IRRP report – Appendix E	Transmission network constraint. Not applicable to Toronto Hydro.

1 **Table 34: End-of-Life Assets – Metro Toronto Region**

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Fairbank TS: T1/T3, T2/T4 Transformers	*2022-2023*	EOL transformers and other HV equipment are identified at these stations for replacement with similar type equipment of the same ratings (discussed further in Section 7.1.1.1 of Needs Assessment).	Current 50/83 MVA transformer is largest 115-27.6 kV standard size.
Fairchild TS: T1/T2 Transformers	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Leslie TS: T1 Transformer	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Runnymede TS: T3/T4 Transformers	*2021-2022*		Proposed 50/83 MVA transformer is largest 115-27.6 kV standard size.
Sheppard TS: T3/T4 Transformers	*2019-2020*		Toronto Hydro determined increase in capacity to larger 75/125 MVA transformer was not required.
Bridgman TS: T11/T12/T13 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations for replacement with higher rated equipment, and are discussed further in Section 7.1.1.2 of Needs Assessment	Included in 2015-2019 Stations Expansion plan.
Charles TS T3/T4 Transformers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.
Duplex TS: T1/T2 Transformers	*2023-2024*		Included in 2020-2024 Stations Expansion plan.
Strachan TS: T12 Transformer	*2020-2021*		Included in 2015-2019 Stations Expansion plan.

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Bermondsey TS: T3/T4 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.3 of Needs Assessment.	Identified as consideration for downsizing, therefore Not Applicable to Toronto Hydro. See section 7.1.1.3 of Needs Assessment for details.
John TS: T1, T2, T3, T4, T6 Transformers and 115 kV breakers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.
Main TS: T3/T4 Transformers and 115 kV line disconnect switches	*2021-2022*		Included in 2015-2019 Stations Expansion plan.
Manby TS: T7, T9, T12 Autotransformers, T13 Step-Down Transformer and rebuild 230 kV yard	*2024-2025*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV C5E/C7E Underground Cable: Esplanade TS to Terauley TS	*2024-2025*	EOL Line section is identified for replacement with similar type equipment, and is discussed further in Section 7.1.1.4 of Needs Assessment.	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV H1L/H3L/H6LC/H8LC: Bloor Street JCT to Leaside JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV L9C/L12C: Leaside TS to Balfour JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.

E7.4.8 Flexibility Considerations

Depending on policy changes by all three levels of government, changes in customer preferences, and decarbonization efforts, there are a large range of outcomes from the energy transition which could impact Toronto Hydro’s distribution system. For example, using the Future Energy Scenarios model, the impact of the high electrification/low efficiency scenario (NZ40 – Low) projects an unprecedented increase in system load which would translate into a significant level of additional investment for the Stations Expansion Program in order to meet such need.

Table 35 shows the estimated costs under this scenario.[41]

Table 35: Estimated Stations Expansion Investment
Needed under Future Energy Scenarios NZ40-Low Efficiency Scenario

CIR Period	Estimated Investment Need ($M)[42]
2025-2029	44
2030-2034	186
2035-2039	527

[41] See Exhibit 2B, Section D4, Appendix A – Future Energy Scenarios Overview and Appendix B – Future Energy Scenarios Report.
[42] This is the additional investment needed incremental to the 2025-2029 investment proposed in this Program, and incremental to the 2030-2034 expenditures forecasted for the Downsview TS and Scarborough TS expansion projects. No expenditures have been forecasted in this Program for 2035-2029. No inflation assumptions have been included.

Downsview TS Business Case

Table of Contents

1 EXECUTIVE SUMMARY

Project Name	Costs	
Downsview TS	$	192.2 M

This project will address forecasted capacity constraints in the Northwest portion of the City due to confirmed large customer requests, the Downsview Area Secondary Plan, and electrification.

The proposed solution is to install a new TS, Downsview TS, in the Downsview Area, roughly between Bathurst TS and Finch TS. This location will permit the new TS to supply the new developments arising from the Downsview Area Secondary Plan, as well as offload the heavily loaded Bathurst, Fairbank, and Finch TSs.

The scope of work involves procuring new land for the new station, and constructing new 230 kV underground cables and duct banks from a Hydro One station, a new building, two new transformers, and one new switchgear. Downsview TS will provide 174 MW of new capacity to supply the Area.

The project is expected to start in Q1 2025 with an in-service date set to Q4 2033. Given the long lead time required to construct a new station, the project will be completed over two stages – Planning and Preparation during 2025-2029 and Construction and Energization over 2030-2034.

The project cost is estimated to be $76.0 million over the 2025-2029 rate period and $116.2 million over the 2030-2034 rate period, including Hydro One contributions and inflation assumptions. Only $14.6 million of the project's estimated cost are planned to be capitalized in the 2025-2029 rate period. These costs are related to the completion of site acquisition and preparation, and the completion of civil construction. The remaining project costs will be capitalized at the completion of the project once the station has been energized.

2 BACKGROUND

2.1 Existing Regional Growth

The area under consideration in this Business Case consists of Bathurst TS, Fairbank TS, Fairchild TS, and Finch TS. This area is shown in Figure 1. This area will be called the “Downsview Area” throughout the rest of this document.

In recent years, the Downsview Area has been attracting a large quantity of new load, a trend that is forecasted to persist into the future. On average, the Downsview Area is forecasted to grow by 2.1% per annum.

Table 1 shows the existing load forecast for the stations in the Downsview Area based on firm connection requests. A station is considered to be highly loaded once loading reaches 90% or higher.

Fairbank TS has historically been highly loaded, and is being relieved by the recent expansion work at Runnymede TS. However, the station remains highly loaded, and will require further offloading to adjacent stations.

Finch TS is the next highest loaded station. The station is forecasted to reach capacity in 2025, but is forecasted to be loaded just below its capacity as early as 2024, due to large customer connections in-progress. At this point in 2024, the station will not be able to accommodate new connection requests without first initiating load relief projects.

Some capacity remains at Bathurst TS, but not enough to relieve overloading. Fairchild TS remains the only station with significant capacity in the Downsview Area, however it cannot provide direct relief to the highly loaded Fairbank and Finch TSs due to geography.

Despite remaining capacity at Bathurst and Fairchild TSs, and the practical challenges of utilizing Fairchild TS for relief, the entire Downsview Area is forecasted to reach 90% loading by 2031. This signals a lack of capacity at the regional level, which is needed to support new connections, growth, and electrification.

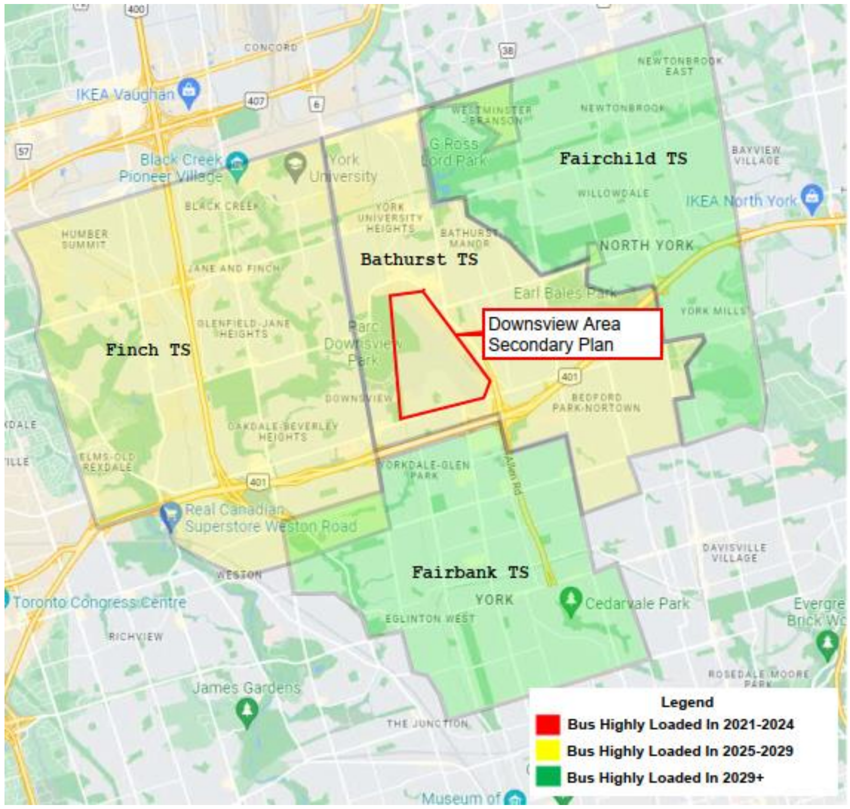


Figure 1 – Map of the Downsview Area and its Stations

Table 1 – Non-Coincident Downsview Area 10-Yr Load Forecast[1]

STATION	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bathurst TS	361	73%	78%	79%	85%	86%	86%	85%	85%	85%	85%	85%
Fairbank TS	182	**104%**	**104%**	**94%**	**93%**	**95%**	**97%**	**97%**	**98%**	**100%**	**101%**	**103%**
Fairchild TS	346	61%	67%	67%	69%	69%	69%	70%	70%	70%	71%	71%
Finch TS	366	69%	77%	**90%**	**98%**	**100%**	**102%**	**102%**	**103%**	**104%**	**105%**	**107%**
Area Non-Coincident %	**1255**	**73%**	**78%**	**81%**	**85%**	**86%**	**88%**	**88%**	**88%**	**89%**	**89%**	**90%**

2.2 Downsview Area Secondary Plan

In 2017, the City of Toronto approved of the Downsview Area Secondary Plan ("DASP"). The area is generally bounded by Sheppard Avenue to the north, Allen Road to the East, Wilson Avenue to the south, and Downsview Park and the Park Commons to the west, as shown in Figure 2.

The DASP plans to expand each district with a mix of commercial, office, industrial and institutional buildings. Mid-rise buildings (10-14 storeys) will be built around the existing TTC Downsview station and lower mid-rise buildings (6-10 storeys). The Allen East District will be primarily be a residential area of 3,500 dwelling units.

[1] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.

DPM Energy, an independent party, has completed a preliminary study which estimates the electrical demand that will materialize from the DASP. This study suggests that load will begin to materialize in 2022 and could materialize up to: 103 MW by 2029, 180 MW by 2034, and 509 MW by 2051. This is equivalent to 8%, 14%, and 41% of the existing Downsview Area's Summer LTR of 1255 MW, as provided in Table 1. As a result, supplying the Downsview Lands with existing regional capacity will not be feasible without capacity investments.

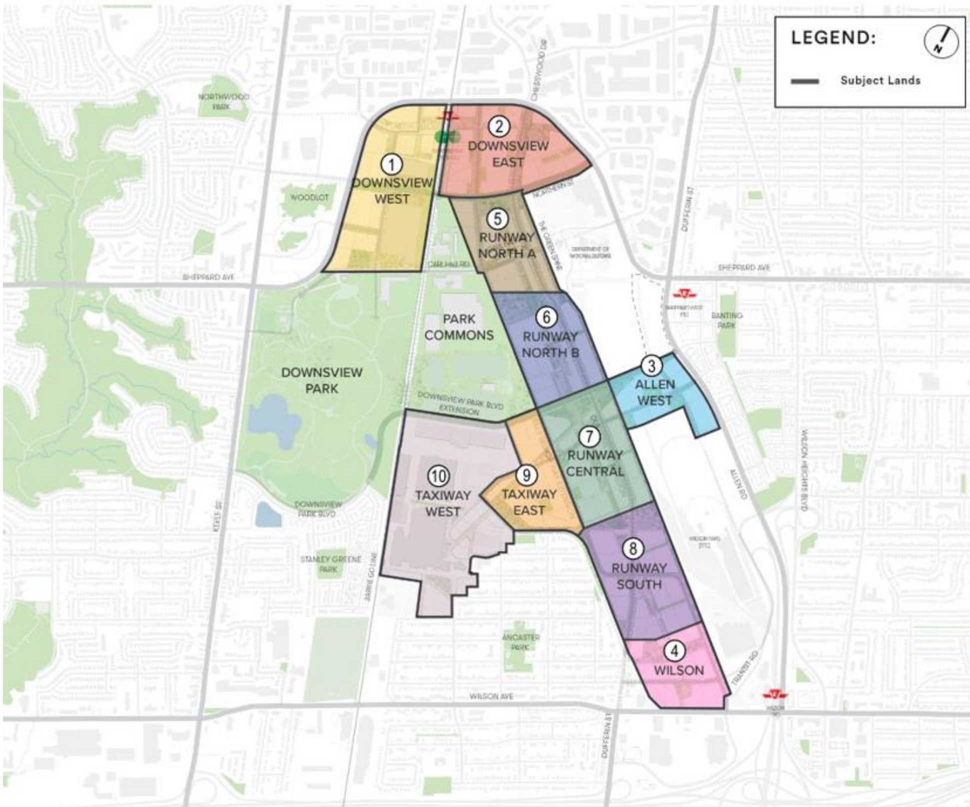


Figure 2 – Downsview Area Secondary Plan Map

2.3 Anticipated Future Loads

Toronto Hydro must ensure that its distribution system is capable of accommodating the anticipated load and generation growth in the City of Toronto. For the City of Toronto to achieve its TransformTO Net Zero Strategy targets, Toronto Hydro is anticipating the overall area load will grow by 40-70% over the next 20 years, largely due to the electrification of heating and transportation. As this transition occurs, Toronto Hydro must ensure that its distribution system is not a barrier to new customers looking to access its system, nor to existing customers looking to decarbonize.

Additionally, two existing large customers in the Downsview Area have approached Toronto Hydro to inquire about expanding their load by an additional 85 MW by 2030. These inquires have not been explicitly included in any forecasts. Although not yet firm requests, such inquiries corroborate the potential for the rapid load growth needed to achieve the TransformTO Net Zero Strategy targets, and the demand for capacity in the area.

Given the current highly-loaded state of the Downsview Area, the addition of the approved DASP, and the likelihood of rapid electrification underway, Toronto Hydro faces a large risk of either overloading its stations or of becoming a barrier to customers. Station loading can be managed in the short term, but medium and long-term solutions are needed to prepare for upcoming developments.

Options with several-year lead times (such as station expansion) must be considered far ahead of need to ensure that cost-effective solutions are pursued in a least-regret manner. Load relief plans for the Downsview Area should also consider the potential for future load growth, to ensure that investments are chosen to be cost-effective in the long term.

3 DOWNSVIEW AREA LOAD FORECAST – LOAD SENSITIVITY ANALYSIS

3.1 Peak Demand Forecast with Downsview Load

The Peak Demand Forecast only extends to 2031; however, as an additional approach to the sensitivity analysis, we will assume that the total Downsview Area load growth past 2031 is provided exclusively by the DASP. The NA forecast already includes consideration for the DASP up until 2031.

A preliminary study from DPM Energy estimates the electrical demand that will materialize from the Downsview Area Secondary plan. The annual load growth from this forecast over 2032-2051 was first adjusted to 70%[2], and then added to the 2031 station loads from the Peak Demand Forecast. The results are provided in Table 2, and referred to as the "25 Year Forecast" hereafter.

Table 2 - Estimated Station Loads under the 25 Year Forecast

STATION	Summer LTR (MW)	2021 (Actuals)	2024	2029	2034	2039	Year 100% Capacity is Reached
Bathurst TS	361	67%	78%	83%	90%	**98%**	2040
Fairbank TS	182	**104%**	**93%**	**104%**	**115%**	**124%**	2029
Fairchild TS	346	61%	69%	71%	71%	71%	N/A
Finch TS	366	69%	**98%**	**106%**	**113%**	**117%**	2025
Area Non-Coincident %	**1255**	**71%**	**84%**	**90%**	**95%**	**100%**	2039

This forecast shows that by 2039 the Downsview Area as a whole will reach capacity, with substantial load growth continuing past then. Prior to that, significant overloading is forecasted at Fairbank TS and Finch TS, which cannot be directly relieved by Fairchild TS, the only station with capacity, due to geography. The 25 Year Forecast indicates that regional capacity constraints will persist past the medium term, and worsen further into the long term.

3.2 Future Energy Scenarios

Depending on policy changes by all three levels of government, changes in customer preferences, and decarbonization efforts, there is a large range of outcomes which may impact Toronto Hydro's distribution system. To prepare for this range, Toronto Hydro commissioned the development of a long-term modelling tool known as Future Energy Scenarios or FES. The Future Energy Scenarios model projects what the demand would be under various policy, technology and consumer behaviour assumptions that are linked to the varying aspirations, goals, targets and constraints of decarbonizing the economy by 2040 or 2050.

[2] THESL's standard bus load forecasting methodology adjusts new customer load to 70% of the requested load in order to forecast bus load impacts.

Across the six modelled Future Energy Scenarios, Toronto Hydro expects that all but one station will become heavily loaded by 2035, and that the area as a whole will become overloaded between 2030 and 2037. Table 3 provides the station and area loading under the Future Energy Scenarios, and Figure 3 illustrates the area non-coincident loading under the Future Energy Scenarios. The Future Energy Scenarios do not specifically consider the DASP.

Table 3 – Non-Coincident Downsview Area Loading under Future Energy Scenarios

STATION	Summer LTR (MW)	2021	2024	2029	2034	2039	Year 100% Capacity is Reached[3]
Bathurst TS	361	67%	78-80%	82-89%	89-**101%**	95-**114%**	2034-N/A
Fairbank TS	182	**108%**	**114-117%**	**117-127%**	**124-142%**	**130-167%**	2021
Fairchild TS	346	62%	65-66%	67-72%	69-78%	70-84%	N/A
Finch TS	366	69%	**102-103%**	**109-116%**	**118-133%**	**124-150%**	2024
Area Non-Coincident %	**1255**	**72%**	**86-88%**	**91-98%**	**97-109%**	**102-122%**	2030-2037

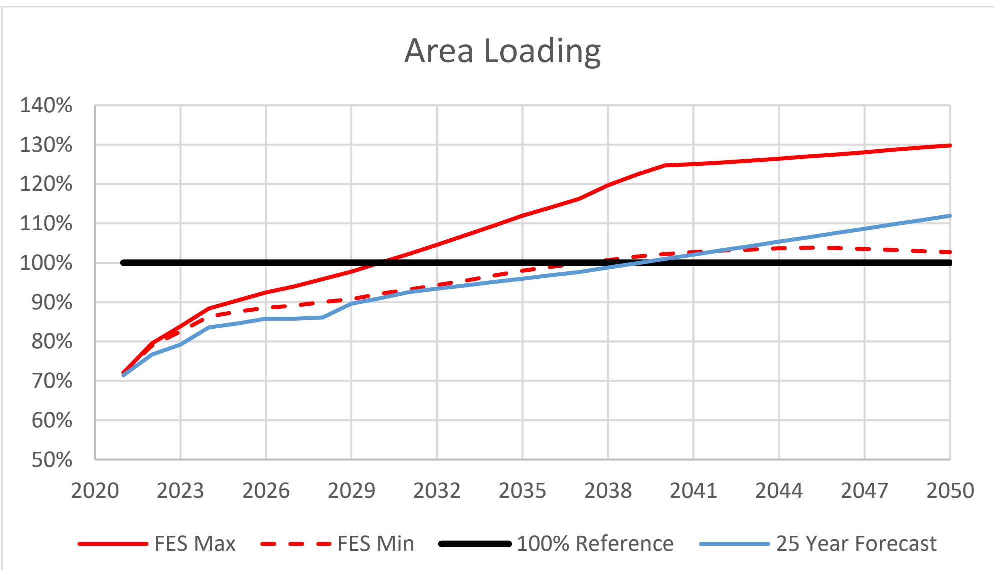


Figure 3 - Non-Coincident Downsview Area 20-Yr Loading from the Future Energy Scenarios Projections

3.3 Sensitivity Conclusions

Two approaches were considered to respectively assess loading impacts to the Downsview Area based on electrification, and the DASP. In both approaches, the Downsview Area is forecasted to be highly loaded by the end of the 2025-2029 rate period. This is marked by overall Downsview Area loading reaching 90% or higher by 2029.

[3] According to the Future Energy Scenarios output only. As a result, this year may be earlier than what is provided in the Peak Demand Forecast.

4 OPTIONS CONSIDERED

To address the needs of the Downsview Area, several options were considered, as outlined in the following subsections.

4.1 Option 1: Status Quo

In practice, the Status Quo option is never recommended when capacity constraints are identified. But this option establishes the minimal level of intervention which is feasible, and illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress.

This option proposes to complete the minimal work needed, and only when immediately needed, in order to maintain station loading throughout the Downsview Area at or below 100%. Specifically, this Option assumes that load transfers will be completed just as each station reaches 100% loading, and only to the extent to keep the station at 100% loading. As a result, load transfer projects will need to be initiated and completed on an annual basis, and as a prerequisite for each new customer connection.

According to the Peak Demand Forecast in Table 1 in Section 2.1, the Downsview Area will not reach 100% loading over 2024-31, and therefore this option is possible. However, this option also presents large operational and reliability risks. Risks rapidly increase past 2029, when at least two stations are forecasted to be overloaded.

As a minimum consequence, the Peak Demand Forecast predicts the Downsview Area will become highly loaded by 2031, and the 25 Year Forecast forecasts this to occur at 2029. Once highly loaded, customer connections become challenging to accommodate in a timely manner, particularly large customer connections (28+ MVA). Further, connection costs charged to individual customers tend to increase, since pre-requisite load transfers are commonly needed to accommodate the new customers.

The cumulative load transfers needed according to the 25 Year Forecast is shown in Figure 4, and increases by approximately 17 MW annually starting in 2029. In total, 194 MW in load transfers would be needed over 2029-2039. After 2039, the Downsview Area is forecasted to be overloaded, and this option is no longer feasible.

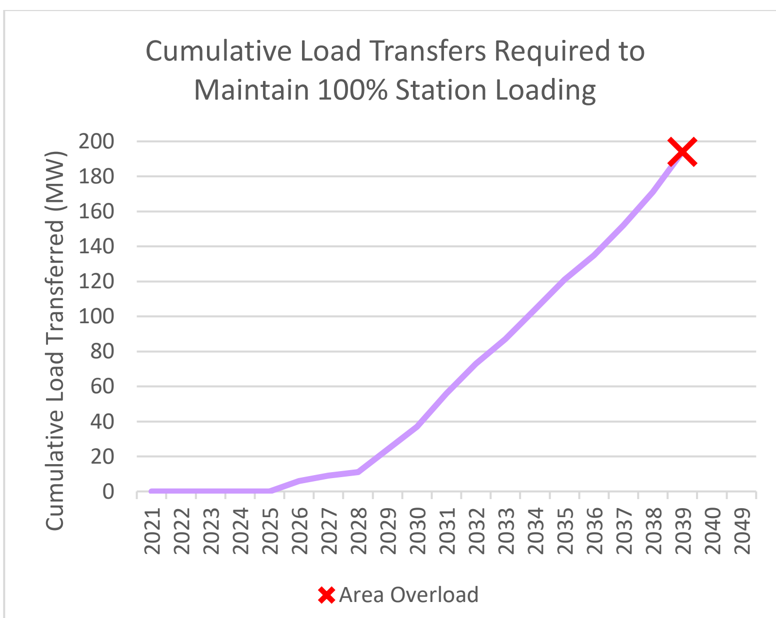


Figure 4 – Cumulative Load Transfers Required Over Time

The FES projections predict a much more rapid load growth, and by contrast load transfers would be needed over the 2024-2037 period. The FES projections predict that the Downsview Area will become overloaded by 2030-2037.

Aside from the cost impacts needed to complete the load transfers, there is also substantial operational risk involved in running stations at 100% load. The lack of capacity at Toronto Hydro's stations results in two negative impacts. First, it prevents new customers from connecting to the grid and burdens customers with higher connection costs. Second, it reduces the reliability of the station and may result in load shedding. These impacts would result in a detriment to Toronto Hydro's "Customer Focused" performance outcomes.

When a customer submits a connection request to a highly loaded station, Toronto Hydro must either offload the station by first completing a load transfer, or connect the customer to a station with capacity located further away. Both options results in higher costs and timelines for customers to connect. When multiple neighbouring stations are highly loaded, these options become even more limited, and connection costs and timelines increase further. Since these load transfers must be completed on-demand as needed and in highly loaded areas, this option carries substantial execution risk which is expected to further increase connection timelines.

If a single station asset is lost at a station whose load exceeds capacity, then Toronto Hydro would need to shed load[4] to avoid damaging the remaining assets. Consequently, a lack of station capacity results in reduced reliability at the station, which affects tens of thousands of customers and typically 100-300 MW of customer load per station. Because of the significant impacts to customer connections and reliability, this option is only considered as a short-term, interim solution.

In conclusion, this option is not a feasible solution. It requires a high level of risk to be maintained and managed for an unacceptably long period. Into 2039 and past 2039, this option cannot be implemented at all since the entire Downsview Area will reach 100% loading.

4.2 Option 2: Load Transfers

The Load Transfer option presents what is needed to maintain station loading in a state which does not adversely affect daily operations nor incumber new customer connections, using existing station capacity.

This option proposes to complete load transfers on a planned basis, once at the start of each 5-year rate application period, to maintain station loading throughout the Downsview Area at or below 90% over the period. This is done while regional capacity remains, in order to free station capacity ahead of load growth and new customer connections. As a result, capacity constraints will not be felt during each period.

The Peak Demand Forecast provided in Table 1 in Section 2, shows that the Downsview Area reaches 90% loading in 2031, and each FES Outlook estimates that the Downsview Area will exceed 90% loading by 2029. Therefore, this Option is only considered feasible up to 2029, with risk that this option may become infeasible even earlier than 2029. An estimated 149 MW in load transfers would be required over 2024-2029 under this Option.

In conclusion, this option is not a feasible solution, since it can only be implemented up to 2029. To address needs in time for the 2030-2034 period, other options must be initiated in the 2025-2029 period.

[4] Load Shedding is the process during which Toronto Hydro temporarily shuts down power supply to a limited number of customers, in order to reduce its station load below its station capacity. Power supply is restored to customers when doing so would no longer result in an overload. When needed, load shedding is generally rotated across customers for a few hours each, so that no customers experience long duration outages while others experience no outages at all.

4.3 Option 3: Non-Wires Solutions

This Option considers the possibility of addressing high loading and overloading within the Downsview Area using Non-Wires Solutions (”NWSs”), specifically the Flexibility Services segment. For further explanation on NWSs, please refer to the 2025-2029 Rate Application, E7.2 Non-Wires Solutions Program.

NWSs include the means to reduce the peak load of a targeted area, without increasing station capacity, and is designed to help address short-to-medium term capacity constraints. The Flexibility Services segment of the NWSs program includes local demand response (“LDR”).

LDR is able to reduce peak load through contracts with customers or aggregators to reduce their load during times of peak demand. As a result, the quantity of peak load which can be addressed is limited by the capability of customers to reduce their demand on Toronto Hydro’s distribution system. According to the 25 Year Forecast, 193 MW of LDR capacity would be needed by 2044 in order to maintain the Downsview Area loading at 90%. Such a large quantity of LDR capacity is unprecedented and is far beyond customer capability in the foreseeable future. For this reason, this option is not considered feasible as a long-term solution.

A key difference between LDR and other solutions, is that since it is a contracted service provided by customers or aggregators, LDR requires an annual cost. Therefore, as a long-term solution, it is possible for the cumulative LDR costs to exceed expansion costs. Similarly, because it is a contracted service, Toronto Hydro does not directly own any assets and faces operational and longevity risks due to dependency on third parties. For these reasons, LDR is best considered a short-to-medium term solution.

In conclusion, this option is expected to be able to address system needs in the short-to-medium term, but poses large long-term feasibility, operational, and financial risks.

4.4 Option 4: Station Upgrades

This option considers the possibility of expanding the capacity of existing DESNs in the Downsview Area by increasing the capacity of the limiting component(s) of the DESN. Such components may be: power transformers, secondary cables, circuit breakers, or buses. Generally, this allows for an incremental increase in station capacity.

All stations in the Downsview Area are already sized to their maximum ratings. Therefore, this option is not feasible.

4.5 Option 5: New DESN(s)

This option considers adding one or more new DESNs at the existing stations in the Downsview Area, referred to as “station expansion”. A typical DESN provides 174 MW of new capacity and supplies 12 new feeders. This option provides the benefit of new capacity, but avoids the site procurement and transmission connection costs required of a new station.

Of the four existing stations in the Downsview Area, only two have space surrounding the station which may potentially be considered for station expansion: Fairchild TS, and Finch TS. Bathurst TS and Fairbank TS are located in urban neighborhoods, surrounded by residential and small commercial buildings where expansion would not be feasible. Aerial views of the existing stations are provided in Figure 5 below.

Figure 5 – Aerial Overview of Existing Stations in the Downsview Area

Although some space may be available at Fairchild TS, expansion of this station is not well suited to meet the needs of the Downsview Area. First, the existing spare land would likely be insufficient to install a new DESN, and likely new land would need to be procured towards its north, east, or south, which presents feasibility challenges. Those challenges aside, the location of Fairchild TS is also far from Fairbank TS and Finch TS which need load relief, as can be seen in Figure 1 in Section 2. As a result, load relief would have to be achieved by cascading load transfers through Bathurst TS. Similarly, Fairchild TS is also located away from the DASP area, making it challenging to connect the new loads to new capacity which would be installed at Fairchild TS. Finally, Fairchild TS already supplies two DESN and egresses 24 feeders. Egressing another 12 feeders effectively from the same location would present a significant design challenge.

Finch TS has better land availability, and could likely accommodate another DESN, although it faces significant implementation challenges to be discussed later. Additionally, referring back to Figure 1 in Section 2, Finch TS could provide meaningful load relief to Bathurst TS, but not to Fairbank TS. Therefore, cascading load transfers[5] from Fairbank TS through Bathurst TS to Finch TS, would be needed to ultimately relieve Fairbank TS. This will ultimately magnify load transfer needs, discussed later and illustrated in Figure 8, reducing the efficacy of this option.

As a result of the above considerations, the expansion of Finch TS is the only technically feasible expansion option to consider, although it faces significant challenges in utilizing its new capacity. Therefore, the remainder of this option considers the impacts of an expansion only at Finch TS, and the risks involved.

Given a new DESN at Finch TS, Downsview Area loading is shown at 5-year intervals in Figure 6. Despite the addition of the new DESN, the 25 Year Forecast estimates that the Downsview Area loading will reach 90% again by 2041. FES projections show that there is risk of Downsview Area overloading as early as 2036, and the magnitude of the potential overloading increases with time. However, the new DESN is expected to resolve Downsview Area loading issues in the long term.

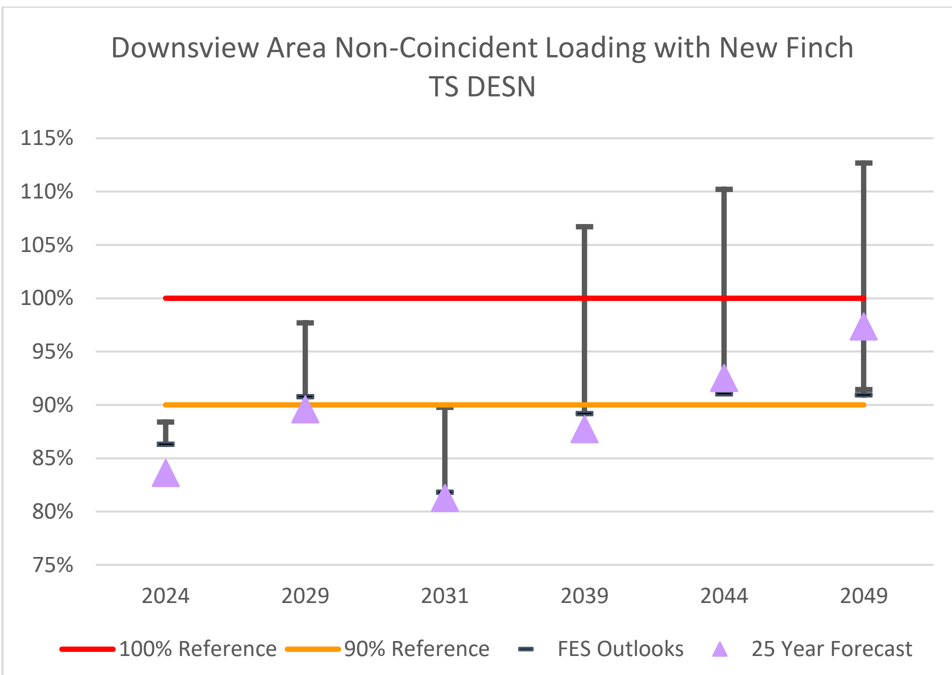


Figure 6 – Downsview Area Loading with a New DESN at Finch TS

The scope of work involved is assumed to be completed entirely by Hydro One, with Hydro One owning all new assets. This is the standard for new Hydro One DESNs, which involve gas-insulated switchgear. Based on a similar expansion completed at Horner TS in 2022, the total cost in Hydro One Contributions is estimated to be $119 million with a project timeline of 6 years. The in-service date would therefore be Q1 2031. The annual estimated Hydro One Contributions are provided in Figure 7.

[5] Cascading load transfer: When one station ("A") cannot directly offload to a neighbouring station ("B") with capacity, the station ("A") must instead first offload to an intermediate station ("C"). Following this, the intermediate station ("C") must transfer the same quantity of load to station ("B") which has the available capacity. Ultimately, station ("A") is offloaded by some amount, station ("B") increases in load by the same amount, and station ("C") experiences no change in load. This is process is called a cascading load transfer.

Because the Peak Demand Forecast forecasts stations loading past 90% before the new DESN at Finch TS will be ready, this option assumes the load transfers presented in option 2 will be completed to manage station loading in the meantime. Once the DESN is ready in 2031, load transfers will again be needed to offload the existing stations onto the new DESN. Finally, although the new DESN will introduce capacity into the Downsview Area, it will not be situated to supply all new DASP load. As a result, load transfers will be needed again from 2035 onward in order to relieve Bathurst TS and/or Fairbank TS as they supply new DASP load. In total, 290 MW in load transfers are expected by 2044. The expected load transfers in 5-year increments are shown in Figure 8.

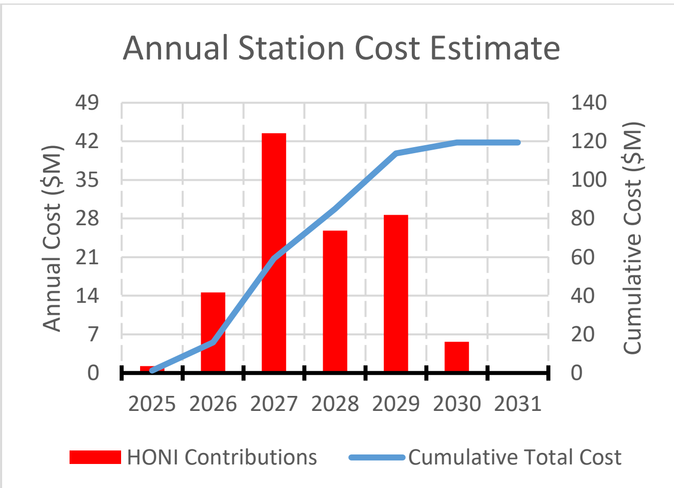


Figure 7 – Estimated Annual Hydro One Contributions for a new DESN at Finch TS

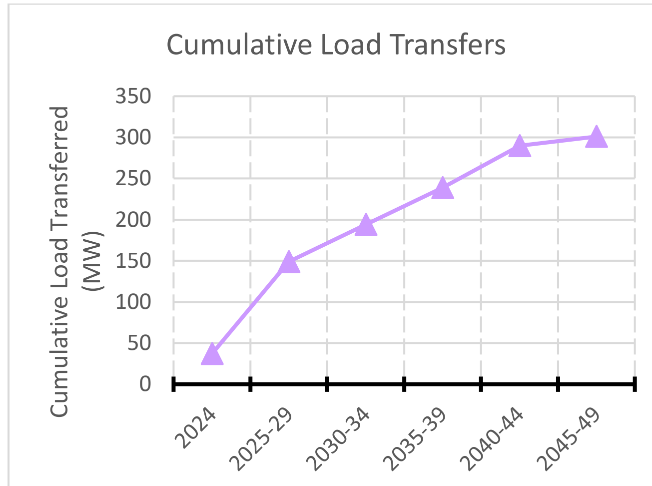


Figure 8 – Cumulative Load Transfers Required for a new DESN at Finch TS

As an exercise intended to quantify the magnitude of load transfers needed, the above load transfer analysis does not consider the significant implementation challenges which are discussed below. Nonetheless, the analysis and Figure 8 show that an unprecedented load of 290 MW will need to be transferred over 20 years in order to make effective use of the new capacity installed in this option. Such a large level of needed load transfer to effectively utilize new capacity signals that the new capacity has been added in the wrong location within the Downsview Area.

In addition to the large magnitude of load transfers needed, a solution at Finch TS would encounter several significant implementation challenges which jeopardize the success of this option in the long term. First, Finch TS already supplies two DESNs and would face similar egressing challenges as Fairchild TS. Second, the DASP area is at the limit of the reach of Finch TS. Given the magnitude of the load expected from the DASP and the distance, reliability and voltage drop concerns would prevent Finch TS from supplying the entire DASP load. Finally, the geographical barriers of Highway 400 and the linear parks that already divide the Finch TS and Bathurst TS service territories would limit the number of feeders that could be extended from Finch TS eastward, effectively bottlenecking new capacity. These geographical barriers are shown in Figure 9**Error! Reference source not found.** and Figure 10**Error! Reference source not found.**.

Figure 9 – Potential Location for New DESN at Finch TS

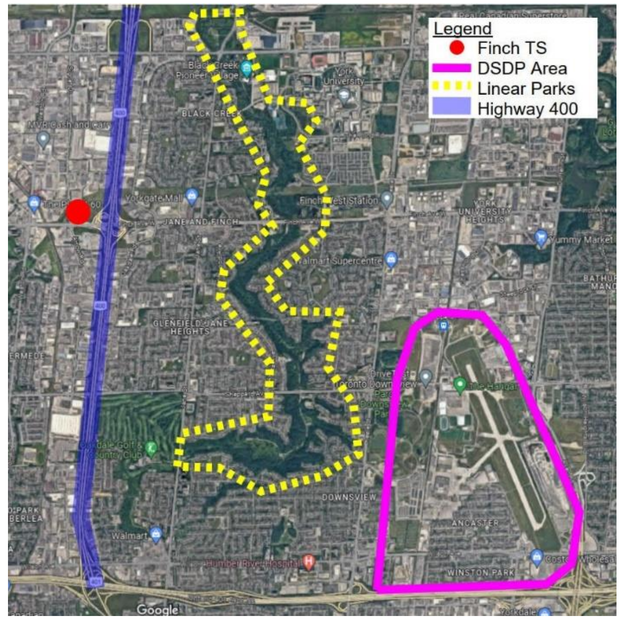


Figure 10 – Finch TS in Relation to the DSDP Area and Geographical Barriers

As a result of these implementation challenges and geographic barriers, there is a large risk that in the long term a significant portion of the new capacity installed at Finch TS will become stranded, while the adjacent Bathurst TS and Fairbank TS become overloaded. This risk is another signal that the new capacity has been incorrectly placed within the Downsview Area.

In addition to execution risk, this option carries a risk to cost which is expected to be even more likely to materialize. In order to overcome at least some of the challenges mentioned, and because of the high quantity of load transfers required, there is a high likelihood that the cost to complete the required load transfers will be significantly higher than average costs. Regarding the magnitude of load as being a driver of cost, this is because when large quantities of load are transferred, accompanying civil work such as new poles, duct banks, and/or cable chambers must be also be constructed.

In conclusion, the expansion of Finch TS is the only existing station in the Downsview Area which can accommodate an expansion. The expansion of Finch TS would introduce 174 MW of new capacity to the Downsview Area, and is expected to bring Downsview Area loading down to 90% until 2041. To achieve this outcome, an estimated $119 million in Hydro One Contributions is needed over 2025-2031, and an unprecedented 290 MW in load transfers is needed over 2024-2044. Because of congestion and geographical barriers, there is a high risk in achieving the total magnitude of load transfers required, which is expected to result in higher than average load transfer costs and stranding of the new capacity provided. The mentioned large risks and the need for an excess quantity of load transfers has motivated consideration of option 6, which seeks to add new capacity directly where it is needed.

4.6 Option 6: New Station (“TS”)

This Option considers building a new transformer station within the Downsview Area, in order to bring new capacity to the area. Because the station will be newly constructed, it can be situated to facilitate the offloading of adjacent stations and/or the connection of new loads.

In particular, this Option proposes to build a new transformer station, named “Downsview TS”, within or on the border of the DASP area. Not only will this facilitate supply of the DASP loads directly, but the DASP area is also located in proximity to all stations in the Downsview Area requiring load relief: Bathurst TS, Fairbank TS, and Finch TS. Therefore, a new station in the DASP area will also be well placed for providing load relief. Similar to option 4, this option considers the installation of one new DESN providing 174 MW of new capacity and suppling 12 new feeders.

Given Downsview TS, the Downsview Area loading is shown at 5-year intervals in Figure 11. Despite the addition of the new DESN, the 25 Year Forecast estimates that the Downsview Area loading will reach 90% again by 2041. FES projections show that there is risk of Area overloading as early as 2036, and the magnitude of the potential overloading increases with time. However, the Downsview TS is expected to resolve Downsview Area loading issues in the long term. To mitigate the risk of overloading in the long term, Downsview SS (introduced below) is proposed to be constructed with the provision to install a second DESN in the future, when it is needed.

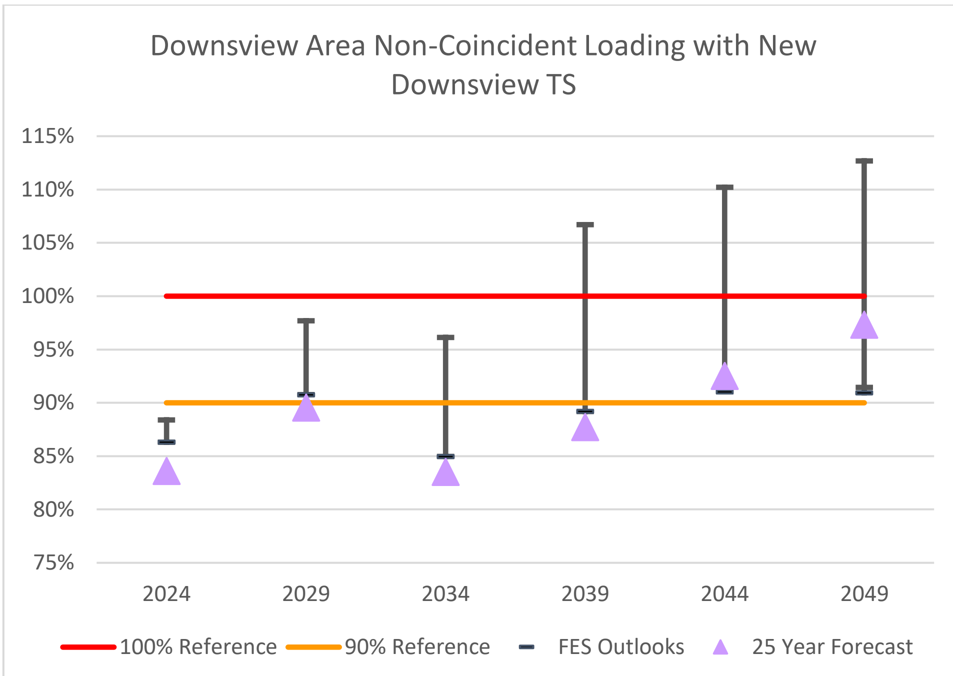


Figure 11 – Downsview Area Loading Following the Energization of Downsview TS

The scope of work of this option involves both a Hydro One and Toronto Hydro portion. The Hydro One portion includes the construction of a new switching station ("Downsview SS") in the vicinity of the Hydro One right-of-way along Finch Ave W, which will serve as the supply and demarcation point for Toronto Hydro's new Downsview TS. The Toronto Hydro portion of work will include the procurement of land for Downsview TS and the construction of: 230 kV underground cables and duct banks from Downsview SS to Downsview TS, a new station building, two primary circuit breakers and transformers, and one switchgear. Because of the large scope of work, Downsview TS's in-service date is estimated to be Q4 2033, assuming it begins in Q1 2025.

Based on estimates of the costs for each major asset installed, and an estimated schedule of the project, an annual cost estimate was developed and is shown in Figure 11. The total cost over 2025-2033 is estimated to be $170 million, excluding inflation assumptions, comprising of $118 million in Toronto Hydro costs and $52 million in Hydro One Contributions.

Because the Peak Demand Forecast anticipates stations loading past 90% before Downsview TS will be ready, this option assumes the load transfers presented in option 2 will be completed to manage station loading in the meantime. Once Downsview TS is ready in 2034, load transfers will be completed to offload the existing stations. Because Downsview TS will be located in the vicinity of the DASP area, it will be able to directly supply the new loads without additional load transfers. As a result, no significant load transfers are anticipated until the Downsview Area loading is forecasted to reach 90% again in 2042. In total, 252 MW in load transfers are expected by 2044. The expected load transfers in 5-year increments are shown in Figure 12. Load transfers increase in 2045 again to prevent overloading at Downsview TS.

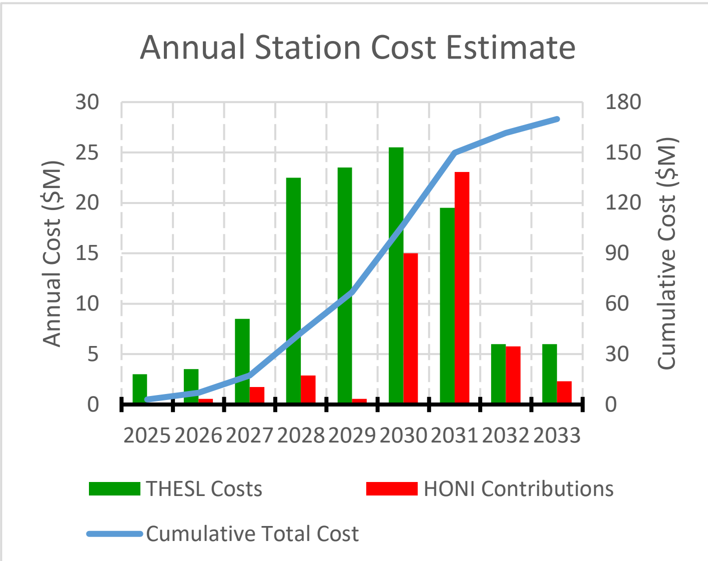


Figure 12 – Estimated Annual Expenditures for Downsview TS[6]

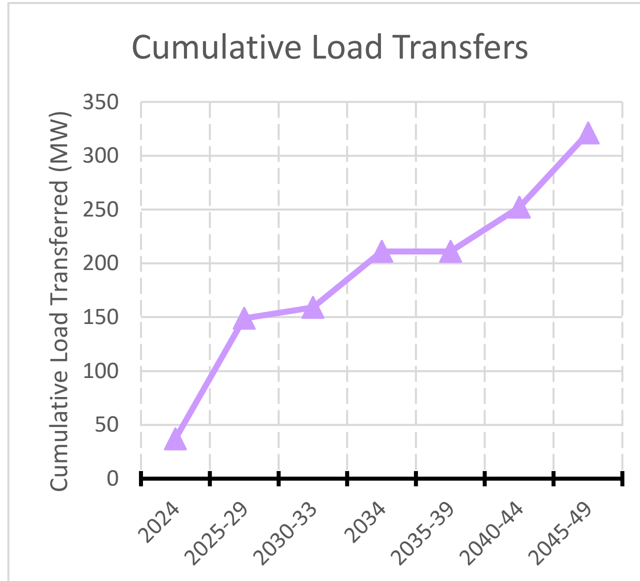


Figure 13 – Cumulative Load Transfers Required for Downsview TS

In conclusion, this option presents a feasible solution by constructing a new Downsview TS and introducing 174 MW of new capacity to the Downsview Area. This investment is expected to bring the Downsview Area loading down to 90% until 2041. To achieve this outcome, an estimated $170 M[6] of expansion work is needed over 2025-2033, and an estimated 252 MW in load transfers is needed over 2024-2043. This option will also include the provision to install a second DESN in the future to mitigate the risk of subsequent overloading in the Downsview Area in the long term.

[6] Excluding inflation assumptions

5 OPTION ANALYSIS AND RECOMMENDATION

The key results of the options studied are summarized in Table 4. Options were considered in order of increasing level of intervention, until an acceptable option was identified. This ultimately led to the identification of the proposed option, Option 6 – New TS, as the only option capable of meeting system needs with reasonable risks.

Table 4 – Summary of Options

Option (Increasing in Level of Intervention)	Decision	Reason for Decision	Decision Criteria				
			Acceptable Solution Outside of Short Term	Cumulative Load Transfers or NWSs Required [by 2044 or Earlier] (MW)[7]	Operational + Customer Connection Risks	Execution Risk	Risk of Subsequent Overloading
1 – Status Quo	Reject	This Option is only viable as a short-term solution.	No	N/A – viable only in short term	High	Medium	Forecasted Overload
2 – Load Transfers	Reject	This Option can only manage loading until 2029.	No	N/A – viable only in short term	Low	Minimal	Forecasted Overload
3 – NWSs	Reject	NWSs are not designed to be long term solutions. Very high execution risk due to unprecedented quantity of NWSs needed.	No	193	High	Very High	Mitigated
4 – Station Upgrades	Reject	Technically infeasible: Station equipment is already sized to maximum ratings.	No	N/A	N/A	N/A	N/A
5 – New DESN(s)	Reject	High execution risks, likelihood of stranded capacity, and excessive quantity of load transfers drive the need for an alternative solution.	Yes	290	Minimal	High	Unmitigated
6 – New TS	**Accept**	Meets system needs with reasonable risks.	Yes	252	Minimal	Medium	Mitigated

[7] Load relief (as load transfers or NWAs) required past 2044 is not considered in this Options Comparison, since the Downsview Area is forecasted to exceed 90% loading again in 2044, given Options 5 or 6. At that point, additional new capacity may be considered rather than additional load transfers or NWAs.

Option 1 – Status Quo, as mentioned in Section 4.1, is never recommended when capacity constraints are identified, but illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress. Since this option is only viable in the short term, it was rejected. Similarly, the analysis for Option 2 – Load Transfers showed that the Option is only viable up until 2029, and as a result it was also rejected.

Option 3 – NWSs would be required indefinitely and would require an unprecedented quantity of load to be addressed, 193 MW. As mentioned in Non-Wires Solutions Program Narrative E7.2.1.1, NWSs are “designed to help address short-to-medium term capacity constraints”, and are not designed to be long term solutions. Moreover, Toronto Hydro’s NWSs over 2015-2019 have targeted a maximum of 10 MW, and the Program over 2025-2029 proposes a maximum target of 30 MW (see E7.2.1.4). As a result, a target of 193 MW by 2044 is highly unprecedented which translates into a very high execution risk. Therefore, because it is not designed to be a long-term solution and its very high execution risk, this option was rejected.

Option 4 – Station Upgrades was considered, but all station equipment in the Downsview Area is already sized to maximum ratings and cannot be further upgraded. Therefore, this option is technically unfeasible and was rejected.

Option 5 – New DESN(s) was considered for each of the 4 existing stations within the Downsview Area; but as mentioned in Section 4.5, only Finch TS could accommodate a new DESN. Although possible, a new DESN at Finch TS would be especially difficult to utilize effectively in the Downsview Area, due to: existing congestion, geographic barriers, and distance from the DASP area. These challenges translate into high execution risks, an expectation of stranded capacity at Finch TS (inaccessible to the rest of the Downsview Area), and an expectation for higher than typical load transfer costs. Finally, because Finch TS is remote from the DASP area and is not central to the broader Downsview Area, this option is forecasted to require a remarkably high quantity of load transfers, 290 MW by 2044, to redistribute the new capacity across the Downsview Area. As a result of the many significant risks, challenges, and inefficiencies presented by this option, this option was ultimately rejected.

Motivated by the challenges encountered in its analysis of option 5, Toronto Hydro next considered installing new capacity both within the DASP area where new capacity is needed most, and in a central location within the broader Downsview Area to facilitate relief of the existing stations. This resulted in Option 6 – New TS which specifically considers installing a new TS within the DASP area, and whose details are reviewed next.

Because of the proposed placement of the new TS, it is suited to offload existing stations and directly supply the new DASP loads, which is the major driver of load growth in the broader Downsview Area. This results in a minimal execution risk in terms of addressing system needs once the new TS is in service. However, the construction of a new TS is a long and complicated project; and therefore, overall execution risk was evaluated as Medium. Because of the designed placement of the new TS, the required load transfers of this Option are less than in the previous option 5 at 252 MW. Option 6 also includes a provision to address the risk of subsequent overloading in the long term (illustrated in Figure 11), by permitting a second DESN to be installed at the newly constructed TS, whereas no such provision exists in option 5.

In light of the multiple benefits of Option 6 – New TS shown over Option 5 – New DESN(s), and given the multiple significant drawbacks of Option 5, Toronto Hydro selected Option 6 – New TS as the only reasonable solution to address capacity needs within the Downsview Area. Toronto Hydro proposes to implement option 6 with its Downsview TS Project included in its 2025-2029 rate application, E7.4 Stations Expansion Program.

6 CONCLUSION

Toronto Hydro has identified a need for additional capacity within the Downsview Area due to forecasted high station loading in the medium term, and forecasted Area overloading in the long term from the Downsview Area Secondary Plan (“DASP”).

To address this need, Toronto Hydro has considered multiple options including: Status Quo, Load Transfers, NWSs, Station Upgrades, New DESN(s), and New TS.

When considering short-to-long term needs, project costs, risks, and secondary benefits, Toronto Hydro concluded that its Option 6 – New TS is the only reasonable option which addresses system needs.

The recommended option will construct a new TS, Downsview TS, which will provide 174 MW of new capacity to the Downsview Area, with forecasted energization in Q4 2033. The proposed location of Downsview TS is in proximity to the lands of the DASP, and also central to the Downsview Area. This will permit it both to directly supply new DASP loads, and relieve the highly loaded Bathurst TS, Fairbank TS, and Finch TS.

The cost to construct the new TS is estimated to be $76.0 million over the 2025-2029 period and $116.2 million over the 2030-2034 period, including Hydro One contributions and inflation assumptions. Only $14.6 million of the project’s estimated cost is planned to be capitalized in the 2025-2029 period. These costs are related to the completion of site acquisition and preparation, and the completion of civil construction. The remaining project costs will be capitalized at the completion of the project once the station has been energized.

Because of the long construction timeline, load transfers and/or NWSs will be needed in parallel with construction of the new TS. An estimated 149 MW in load transfers or NWS capacity will be needed by 2029, and a subsequent 62 MW between 2030-2034.

Downsview TS will be constructed with a provision to install an additional 174 MW of capacity when needed in the future. This will address the risk of subsequent high loading or overloading. The 25 Year Forecast forecasts 90% loading to reoccur after 2041, and the FES projections project this to occur as early as 2034 despite the energization of Downsview TS.

The proposed investments will address upcoming high loading in the Downsview Area, support the City of Toronto’s Downsview Area Secondary Plan, and prepare the Downsview Area to support electrification over the next 10-20 years.

Scarborough TS Expansion Business Case

Table of Contents

1 EXECUTIVE SUMMARY

Project Name	Costs	
Scarborough TS Expansion	$	56.3 M

This project will address forecasted capacity constraints in the East end of the City due to confirmed large customer requests, the Golden Mile Secondary Plan, and electrification.

The proposed solution is to install a new DESN at Scarborough TS, due to its central location in the area, as well as its proximity to the highly-loaded Warden TS.

The scope of work involves constructing a new building, two new transformers, and one new switchgear at the Hydro One-owned station, which will provide 95 MW of new capacity. The new transformers and new building will be constructed with a provision to install a second switchgear. When needed, the second switchgear will provide an additional 95 MW of new capacity to the area.

The project cost is estimated to be $51.3 million in the 2025-29 period, and $5.0 million in 2030. The project's in-service date is planned for December 2030, and the full $56.3 million project cost is planned to be capitalized in 2031 following energization.

2 BACKGROUND

2.1 Existing Regional Growth

The area under consideration in this Business Case consists of: Bermondsey TS, Ellesmere TS, Scarborough TS, and Warden TS. This area is show in Figure 1. This area will be called the "Scarborough area" throughout the rest of this document.

In recent years, the Scarborough area has been attracting a large amount of new load, and that trend is forecasted to persist into the future. Recent large projects in progress involve an 84 MVA data centre, an 80 MVA Metrolinx connection for the Ontario Line, and a 36 MVA TTC connection for the Scarborough Subway Extension. On average, the area is forecasted to grow by 4.1% per annum over the next 10 years.Table 1 shows the existing load forecast for Scarborough TS and its adjacent stations based on firm connection requests. A station is considered to be highly loaded once loading reaches 90% or higher.

Warden TS is forecasted to quickly become highly loaded due to the onset of new large customer connections. Load transfer projects to relieve Warden TS have already been initiated and included in the forecast to prevent overloading, but high loading persists due to demand in its service territory.

Ellesmere TS is forecasted to become highly loaded by the end of the 2025-29 rate period. This growth is being driven by several large customer connection requests, including transit. The expectation is that new customer connections will become challenging to accommodate, particularly due to high feeder loading.

While Bermondsey TS is not forecasted to reach the high load threshold of 90%, its load is forecasted to double over the next 10-years. This rapid load growth is driven mostly by the Ontario Line transit project, a new large data centre connection, and load transfers from Warden TS.

There is a consistent trend of high growth throughout the Scarborough area, and by 2031 it is forecasted to be highly loaded at 90%. This signals a lack of capacity at the regional level, which is needed to support new connections, growth, and electrification.

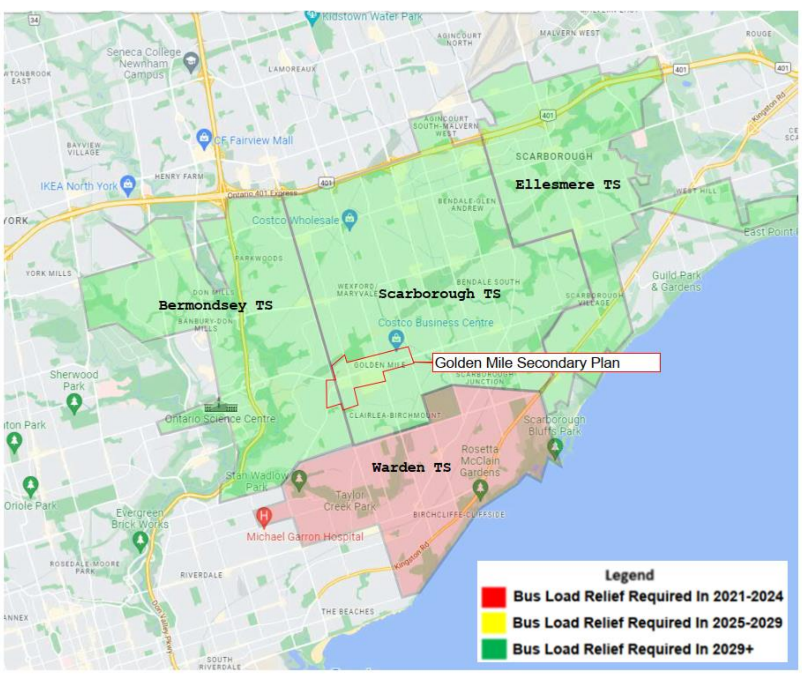


Figure 1 – Map Scarborough TS and its Adjacent Stations

Table 1 – Non-Coincident area 10-Yr Load Forecast[1]

STATION	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bermondsey TS	348	45%	57%	67%	71%	73%	73%	85%	85%	85%	86%	88%
Ellesmere TS	189	63%	65%	71%	84%	88%	88%	89%	**95%**	**96%**	**96%**	**96%**
Scarborough TS	340	64%	68%	71%	78%	79%	79%	79%	84%	85%	86%	86%
Warden TS	182	80%	85%	78%	**91%**	**92%**	**94%**	**93%**	**93%**	**94%**	**94%**	**95%**
Area Non-Coincident %	**1059**	**61%**	**67%**	**71%**	**79%**	**81%**	**81%**	**85%**	**88%**	**88%**	**89%**	**90%**

2.2 Golden Mile Secondary Development Plan

In 2020, the City of Toronto adopted the Golden Mile Secondary Development Plan ("GMSDP"), which proposes a mixture of residential, commercial, and office building development. The Golden Mile is 113 hectares (280 acres) in size, generally bounded by Victoria Park Avenue to the west, Ashtonbee Road/Hydro Corridor to the north, Birchmount Road to the East and an irregular boundary to the south as shown in Figure 2. The specific area within the map where development will take place is also shown in Figure 1. The development is located at the bottom edge of Scarborough TS and is just outside of Warden TS's service territory.

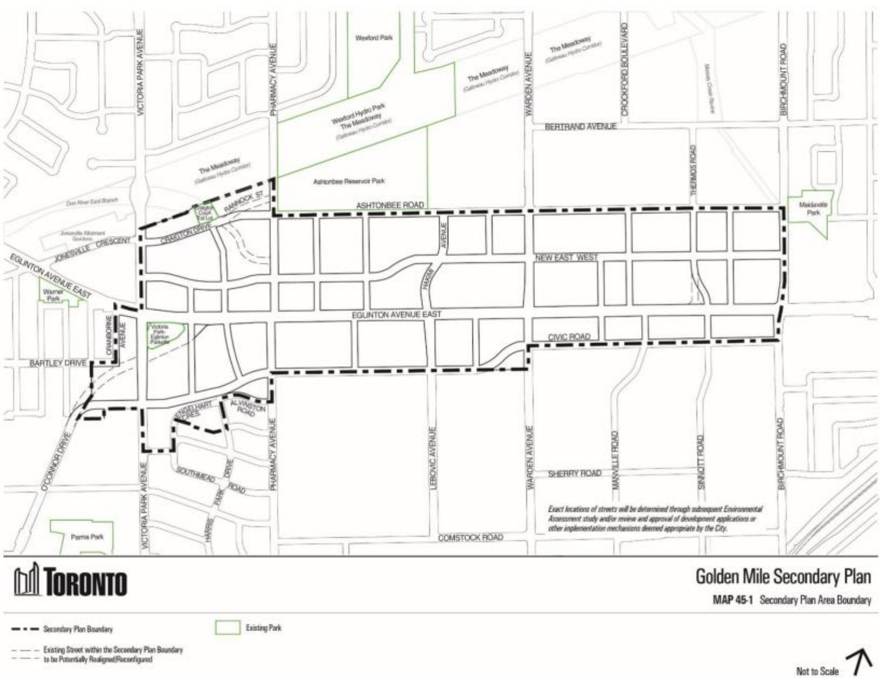


Figure 2 – Golden Mile Secondary Plan Map

[1] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Report, Toronto Region, Dec 2022.

The GMSDP proposes a mixture of residential, commercial, and office building development. The area is expected to build a mixture of mid-rise and tall buildings, creating up to 5,000 new residential units. Additionally, the Plan proposes for each dwelling unit to provide an outlet for EV charging. The main focus of the development is to update the area with current infrastructure and prepare for electrification.

DPM Energy, an independent party, has completed a preliminary study which estimates the electrical demand that will materialize from the Golden Mile Secondary plan. This study estimates that load will begin to materialize in 2030 and could be up to 280 MW by 2040. To meet this demand, station capacity should be available by 2030, and multiple phases of expansion work may be needed by 2040.

2.3 Anticipated Future Loads

Toronto Hydro must ensure that its distribution system is capable of accommodating anticipated load and generation growth in the City of Toronto. As the City of Toronto moves through an energy transition, Toronto Hydro is anticipating its Scarborough area load will grow by 75-105 percent over the next 20 years, largely due to the electrification of heating and transportation. Therefore, regardless of how this transition happens, Toronto Hydro expects that its Scarborough area will face large capacity constraints without additional investment. Over the course of the energy transition, Toronto Hydro must ensure that its distribution system is not a barrier to new customers looking to access its system nor to existing customers looking to decarbonize.

In addition to the GMSDP discussed in the previous Section 2.2, the City of Toronto is also reviewing its Scarborough Centre Secondary Plan with its Our Scarborough Centre Study[2] currently underway. The redevelopment of Scarborough Centre spans an area of 180 hectares, and is focused on densification, improved accessibility, and the introduction of new transit. The development would introduce significant new loads to Ellesmere TS and Scarborough TS.

Given the current highly-loaded state of the area, the addition of the GMSDP, the likelihood of rapid electrification underway, and the likelihood of the Scarborough Centre redevelopment, Toronto Hydro faces a large risk of either overloading its stations or of becoming a barrier to customers. Station loading can be managed in the short term, but medium and long-term solutions are needed to prepare for upcoming developments. In particular, options with several-year lead times (such as station expansion) must be considered far ahead of need to ensure that cost-effective solutions are pursued in a least-regret manner.

[2] https://www.toronto.ca/city-government/planning-development/planning-studies-initiatives/scarborough-centre-review/information-and-reports-scarborough-centre-review/

3 SCARBOROUGH AREA LOAD FORECAST – LOAD SENSITIVITY ANALYSIS

3.1 Peak Demand Forecast with Golden Mile Load

The Peak Demand Forecast only extends to 2031; however, we will assume that the total area load growth past 2031 is provided exclusively by the GMSDP. The result will be called the "25 Year Forecast". The Peak Demand Forecast does not already include consideration for the GMSDP, and for this reason the GMSDP load is added starting in 2030.

A preliminary study from DPM Energy estimates the electrical demand that will materialize from the GMSDP. This study estimates that load will begin to materialize in 2030 and could materialize up to: 283 MW by 2040 and 304 MW by 2051. The annual load growth from this study was first adjusted to 70 percent[3], and then added to the Peak Demand Forecast. The results at 5-year increments are provided in Table 2.

Table 2 - Estimated Station Loads under the 25 Year Forecast

STATION	Summer LTR (MW)	2021 (Actuals)	2024	2029	2034	2039	Year 100% Capacity is Reached
Bermondsey TS	348	45%	71%	85%	**94%**	**101%**	2039
Ellesmere TS	189	63%	84%	**96%**	**96%**	**96%**	N/A
Scarboro TS	340	64%	78%	85%	**99%**	**112%**	2035
Warden TS	182	80%	**91%**	**94%**	**108%**	**120%**	2031
Area Non-Coincident %	**1059**	**61%**	**79%**	**88%**	**98%**	**107%**	2035

Under the 25 Year Forecast, the Scarborough area as a whole is forecasted to exceed 90 percent loading in 2030, soon after the 2025-29 period. By 2031, Warden TS is forecasted to reach capacity and the remaining stations are each forecasted to be highly loaded. Following that, Scarborough TS and the entire Scarborough area are forecasted to reach capacity in 2035. Over the next 3 rate periods from 2025-2039, with each rate period, the Scarborough area is forecasted to rapidly escalate to progressively worse states of loading, as summarized in Table 3.

[3] THESL's standard bus load forecasting methodology adjusts new customer load to 70% of the requested load in order to forecast bus load impacts.

Table 3 – States of Loading in the Scarborough area Over the Next 3 Rate Periods

	2025-2029	2030-2034	2035-2039
Area Highly Loaded (≥ 90%)	✗	✓	✓
All Stations Highly Loaded (≥ 90%)	✗	✓	✓
Area Overloaded (≥ 100%)	✗	✗	✓

In summary, the 25 Year Forecast reinforces the need for new capacity in the Scarborough area for the start of the 2030-2034 period, and shows that this need increases progressively until 2035 when the whole Scarborough area loading is forecasted to reach capacity.

3.2 Future Energy Scenarios

Depending on policy changes by all three levels of government, changes in customer preferences, and decarbonization efforts, there is a large range of outcomes which may impact Toronto Hydro's distribution system. To prepare for this range, Toronto Hydro commissioned the development of a long-term modelling tool known as Future Energy Scenarios or FES. The Future Energy Scenarios model projects what the demand would be under various policy, technology and consumer behaviour assumptions that are linked to the varying aspirations, goals, targets and constraints of decarbonizing the economy by 2040 or 2050.

The 25 Year Forecast described in the previous section is the forecast Toronto Hydro has used to produce its proposed business plan. However, the 25 Year Forecast does not explicitly account for the electrification of heating loads, and therefore may be understated. To bridge this gap, Toronto Hydro has used the FES as a tool to assess the risk posed by electrification.

Across all Future Energy Scenarios, the model projects that all but one station will become highly loaded by 2031, and that the area as a whole will become overloaded between 2030 and 2034. Table 4 provides the station and area loading under the FES, and Figure 3 illustrates the area Non-Coincident loading under the FES.

Table 4 – Non-Coincident area 20-Yr Scenario-Based Load Forecast Results

STATION	Summer LTR (MW)	2021	2024	2029	2034	2039	Year 100% Capacity is Reached[4]
Bermondsey TS	348	44%	69-70%	78-82%	82-89%	84-**95%**	N/A
Ellesmere TS	189	66%	83-85%	**100-113%**	**109-135%**	**120-154%**	2028-2029
Scarborough TS	340	64%	78-80%	87-**94%**	**95-107%**	**100-118%**	2032-2039
Warden TS	182	82%	**102-104%**	**125-134%**	**135-151%**	**140-174%**	2024
area Non-Coincident %	**1059**	**61%**	**80-82%**	**93-99%**	**100-111%**	**104-123%**	2030-2034

[4] According to the Future Energy Scenarios output only. As a result, this year may be earlier than what is provided in the Peak Demand Forecast.

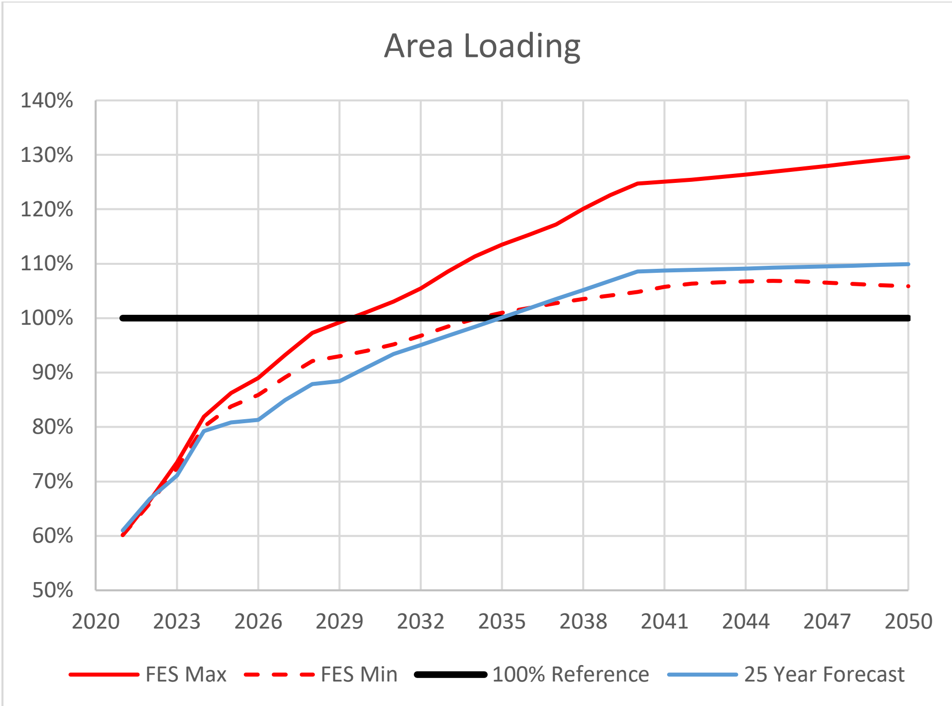


Figure 3 - Non-Coincident area 20-Yr Loading from the FES Projections

In summary, the Future Energy Scenarios also demonstrate the need for new capacity in the Scarborough area for the end of the 2025-2029 period. Furthermore, FES shows that this need may materialize much sooner than predicted by the 25 Year Forecast. Overall, the FES affirms the need for new capacity in the Scarborough area which is predicted by the 25 Year Forecast.

3.3 Sensitivity Conclusions

Two approaches were considered to assess loading impacts to the area based on the Golden Mile Secondary Development Plan (GDSMP) and the Future Energy Scenarios. In both approaches, the Scarborough area is forecasted to be highly loaded near the end of the 2025-2029 Custom-Incentive Rate Filing period. This is marked by overall area loading reaching 90 percent or higher by 2031.

Moreover, both approaches indicate a continuing need for additional capacity into 2040. In fact, the GMSDP's estimated load buildup of 280 MW over 2030-2040, or 26 percent of the area's capacity, is just as aggressive a buildup as the Maximum projection from the FES over the same period. Both approaches predict the Scarborough area overloading over 2030-2035, with load growth continuing thereafter.

The Scarborough Centre Secondary Plan and the resulting Our Scarborough Centre Study result in an additional risk for even further load growth, which has not been explicitly captured in either approach. The redevelopment of Scarborough Centre would add substantial load to the Scarborough area, and reiterates a long term need for new capacity in the Scarborough area.

In conclusion, multiple perspectives were considered when conducting a load sensitivity analysis, and all perspectives conclude with the Scarborough area loading reaching capacity in approximately 7-12 years.

4 OPTIONS CONSIDERED

To address the needs of the Scarborough area, several options were considered, as outlined in the following subsections.

4.1 Option 1: Status Quo

In practice, the Status Quo option is never recommended when capacity constraints are identified. But this option establishes the minimal level of intervention which is feasible, and illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress.

This option proposes to complete the minimal work needed, and only when immediately needed, in order to maintain station loading throughout the Scarborough area at or below 100 percent. Specifically, this option assumes that load transfers will be completed just as each station reaches 100 percent loading, and only to the extent to keep the station at 100 percent loading. As a result, load transfer projects will need to be initiated and completed on an annual basis, and as a prerequisite for each new customer connection.

According to the Load Forecast in Table 1 in Section 2, Warden TS will reach 100% loading in 2024 but the other stations will be under 80 percent loading. Therefore, this option is possible; however, it will present large operational and reliability risks. Risks rapidly increase past 2024, when all scenarios estimate at least 1 station's loading to reach 100 percent.

As a minimum consequence, the Load Forecast predicts the Scarborough area will become highly loaded by the end of the upcoming 2020-24 rate period. Once highly loaded, customer connections become challenging to accommodate in a timely manner, particularly large customer connections (28+ MVA). Further, connection costs charged to individual customers tend to increase, since pre-requisite load transfers are commonly needed to accommodate the new customers. Given the incoming Golden Mile load, the Scarborough area may see more rapid increases in load. The cumulative load needed to be transferred and its required timing is provided in Table 5 below. The area is forecasted to be overloaded in 2035.

Table 5 – Load Transfers Required to Maintain Station Loading ≤ 100%

Load Transfers Required (MW) per Rate Period			
2024	**2025-29**	**2030-34**	**2035-2039**
0	0	14	area Overloaded

The FES projections predict a much more rapid load growth, and by contrast load transfers are needed over the 2024-2033 period. The FES projections predict that the Scarborough area will become overloaded by 2029-34.

Aside from the cost impacts needed to complete the load transfers, there is also substantial operational risks involved in running stations at 100 percent loading. The lack of capacity at Toronto Hydro's stations results in two negative impacts. First, it prevents new customers from connecting to the grid and burdens customers with higher connection costs. Second, it reduces the reliability of the station and may result in load shedding. These impacts would result in a detriment to Toronto Hydro's "Customer Focus" performance outcomes.

When a customer submits a connection request to a highly loaded station, Toronto Hydro must either offload the station by first completing a load transfer, or connect the customer to a farther station with capacity. Both options results in higher costs and timelines for customers to connect. When multiple neighbouring stations are highly loaded, these options become even more limited, and connection costs and timelines increase further. Since these load transfers must be completed on-demand as needed and in highly loaded areas, this option carries substantial execution risk which is expected to further increase connection timelines.

If a single station asset is lost at a station whose load exceeds capacity, then Toronto Hydro would need to shed load[5] to avoid damaging the remaining assets. As a result, a lack of station capacity results in reduced reliability at the station, which affects tens of thousands of customers and typically 100-300 MW of customer load per station. Because of the significant impacts to customer connections and reliability, this option is only considered as a short-term interim solution.

In conclusion, this option is not a feasible solution. This option requires a high level of risk to be maintained and managed for an unacceptably long period, into 2034; and past 2034, this option cannot be implemented at all since the entire area will reach 100 percent loading.

4.2 Option 2: Load Transfers

The Load Transfer option presents what is needed to maintain station loading in a state which does not adversely affect daily operations nor incumber new customer connections, using existing station capacity.

This option proposes to complete load transfers on a planned basis, once every 5-year period, to maintain station loading throughout the Scarborough area at or below 90% over the period. This is done to free station capacity ahead of load growth and new customer connections. As a result, capacity constraints will not be felt during each period.

Given the 25 Year Forecast provided in Table 2 of Section 3.1, the Scarborough area will reach 90 percent loading by 2030. Table 6**Error! Reference source not found.** below shows that 22 MW in load transfers will be needed over the 2025-29 period, and that area loading will surpass 90 percent loading after the 2025-29 period.

Table 6 – Annual Load Transfers Required to Maintain Station Loading ≤ 90%

Forecast	Annual Load Transferred (MW)		
	2024	**2025-29**	**2030-34**
Golden Mile Load	2	22	Above 90%

The FES projections estimate that the Scarborough area will exceed 90 percent loading between 2026-27, making this option infeasible for the 2025-29 period. In addition to GMSDP loads, Toronto Hydro is aware of the Scarborough Centre Secondary Plan but does not have an estimated load profile at this time. This Plan adds further risk to this option.

In conclusion, this option is not a feasible solution, since it can only be implemented up to 2029. To address needs in time for the 2030-2034 period, other options must be initiated in the 2025-2029 period.

4.3 Option 3: Non-Wires Solutions

This option considers the possibility of addressing high loading and overloading within the Scarborough area using Non-Wires Solutions (”NWSs”), specifically the Flexibility Services segment. For further explanation on NWSs, please refer to the 2025-2029 Rate Application, E7.2 Non-Wires Solutions Program.

[5] Load Shedding is the process during which Toronto Hydro temporarily shuts down power supply to a limited number of customers, in order to reduce its station load beneath its station capacity. Power supply is restored to customers when doing so would no longer result in an overload. When needed, load shedding is generally rotated across customers for a few hours each, so that no customers experience long duration outages while others experience no outages at all.

NWSs include the means to reduce the peak load of a targeted area, without increasing station capacity, and is designed to help address short-to-medium term capacity constraints. The Flexibility Services segment of the NWSs program includes local demand response (“LDR”).

LDR is able to reduce peak load through contracts with customers or aggregators to reduce their load during times of peak demand. As a result, the quantity of peak load which can be addressed is limited by the capability of customers to reduce their demand on Toronto Hydro’s distribution system. According to the 25 Year Forecast, 179 MW of LDR capacity would be needed by 2039 in order to maintain the area loading at 90%. Such a large quantity of LDR capacity is unprecedented and is far beyond customer capability in the foreseeable future. For this reason, this option is not considered feasible as a long-term solution.

A key difference between LDR and other solutions, is that since it is a contracted service provided by customers or aggregators, LDR requires an annual cost. Therefore, as a long-term solution, it is possible for the cumulative LDR costs to exceed expansion costs. Similarly, because it is a contracted service, Toronto Hydro does not directly own any assets and faces operational and longevity risks due to dependency on third parties. For these reasons, LDR is best considered for short-to-medium term solutions.

In conclusion, this option is expected to be able to address system needs in the short-to-medium term, but poses large long-term feasibility, operational, and financial risks.

4.4 Option 4: Station Upgrades

This option considers the possibility of expanding the capacity of existing DESNs in the Scarborough area by increasing the capacity of the limiting component(s) of the DESN. Such components may be: power transformers, secondary cables, circuit breakers, or buses. Generally, this allows for an incremental increase in station capacity.

Of all the stations in the Scarborough area, Bermondsey TS, Ellesmere TS, and Warden TS are already sized to their maximum ratings. The Scarborough TS T23 transformer can be upgraded, and this upgrade is already proceeding through Hydro One sustainment plans during the 2025-29 period. The incremental cost to upgrade the end-of-life Scarborough T23 transformer as it undergoes renewal is $0.4 million. The upgrade is planned to be complete in 2028, and will provide an estimated 38 MW of new capacity to the Scarborough area.

Figure 4 below shows the Scarborough area loading after Scarborough TS’s transformer upgrade. After the transformer upgrade, the Scarborough area is projected to exceed 90 percent loading by 2031 and will require load relief.

In conclusion, this option is not a feasible solution, since it can only satisfy system needs up until 2030. To address needs in time for the 2030-2034 period, other options must be initiated in the 2025-2029 period.

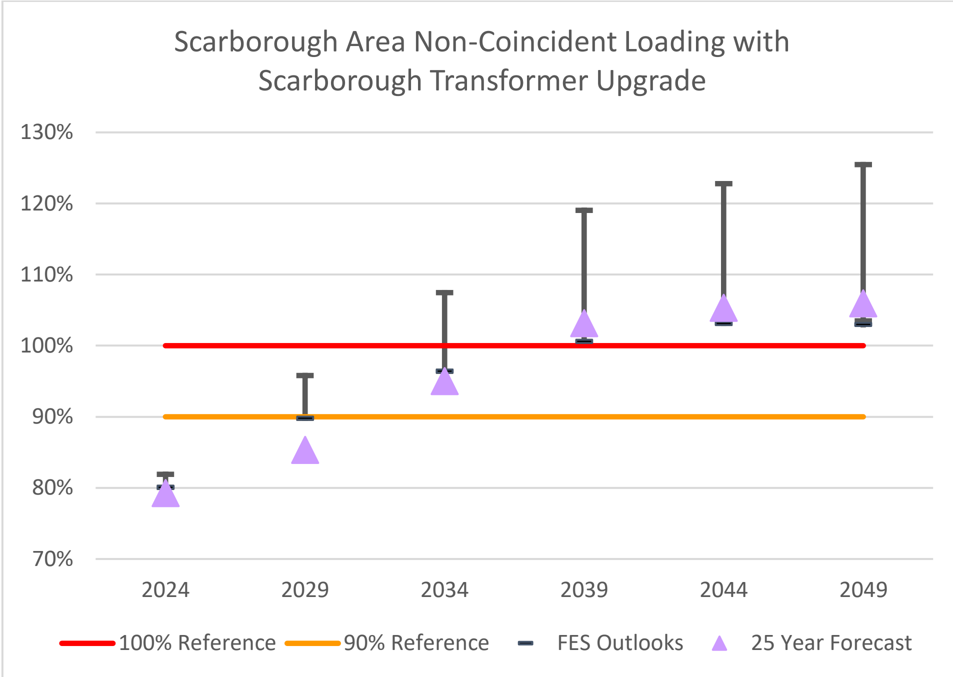


Figure 4 – Scarborough area Loading Following Scarborough TS Upgrade

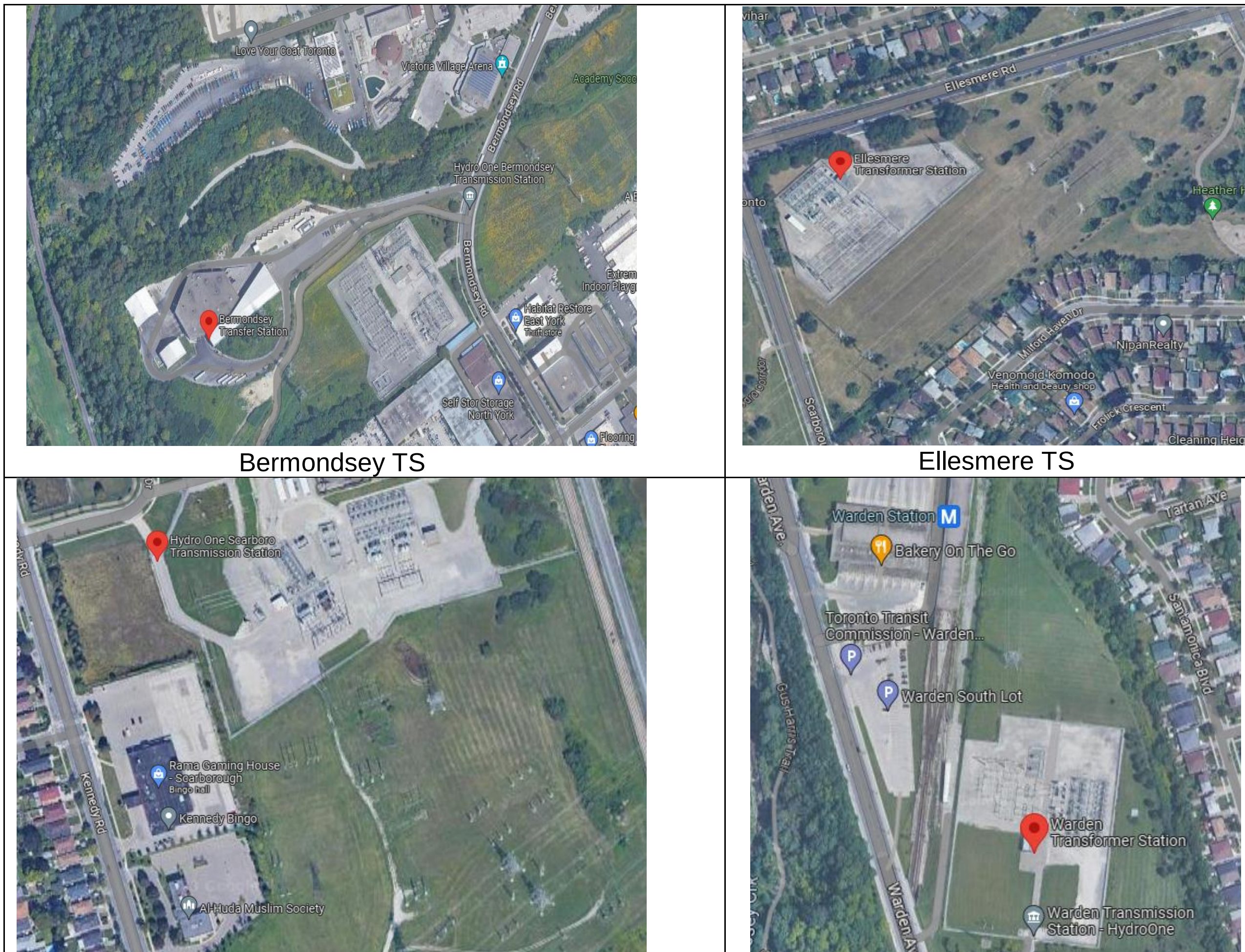
4.5 Option 5: New DESN(s)

This option considers adding one or more new Dual-Element Spot Networks ("DESNs") at the existing stations in the Scarborough area, referred to as "station expansion". A typical Jones DESN provides 95 MW of new capacity and supplies 6 new feeders. This option provides the benefit of new capacity, but avoids the site procurement and transmission connect costs required for a new station.

This option also assumes that option 4.4 Station Upgrades has been completed, introducing 38 MW by 2028, since the Scarborough TS transformer upgrade is already proceeding due to Hydro One sustainment plans.

Of the four existing stations in the Scarborough area, only two have sufficient space at the station to consider expansion and are located in proximity to the Golden Mile area, the source of future load growth. As a result, only these two stations, Scarborough TS and Warden TS, are considered for expansion.

Bermondsey TS already has plans underway to expand its JQ DESN by an additional 6 breakers, which will utilize remaining space. Ellesmere TS does not have enough space for expansion in the current lot. In both cases, new installations directly beneath transmission lines are to be avoided, which eliminates the remaining space around Bermondsey TS and Ellesmere TS. Aerial views of the existing stations are provided in Figure 5 below.



Bermondsey TS | Ellesmere TS | Scarborough TS | Warden TS

Figure 5 – Aerial Overview of Existing Stations in the Scarborough area

The Scarborough area loading is shown at 5-year intervals in Figure 6, given the addition of one new Jones DESN rated for 95 MW and the Scarborough TS transformer upgrade. The new DESN is expected to come in service at the end of 2030. While these investments will address the needs identified for the early 2030-2034 period described in Section 3.1, loading is forecasted to again reach 90% in 2036, signaling the need for subsequent new capacity at that time.

Similarly, the Future Energy Scenarios predict that 90 percent loading may begin and persist as early as 2027, and that area overloading may begin as early as 2035. Therefore, the FES also demonstrate the risk that subsequent new capacity will be needed beyond the new Jones DESN and Scarborough TS transformer upgrade.

To address the risk of subsequently overloading, this option is proposed with the provision to install a second DESN in the future. This will be achieved by installing two 125 MVA dual winding power transformers as part of this project, which is Hydro One's standard equipment for new DESNs at this voltage level, leaving two idle windings free for a future second DESN. The second DESN will provide a subsequent 95 MW of capacity to the area, and can be initiated when needed. Once complete, the second DESN will provide sufficient capacity to keep area loading below 90 percent until 2042.

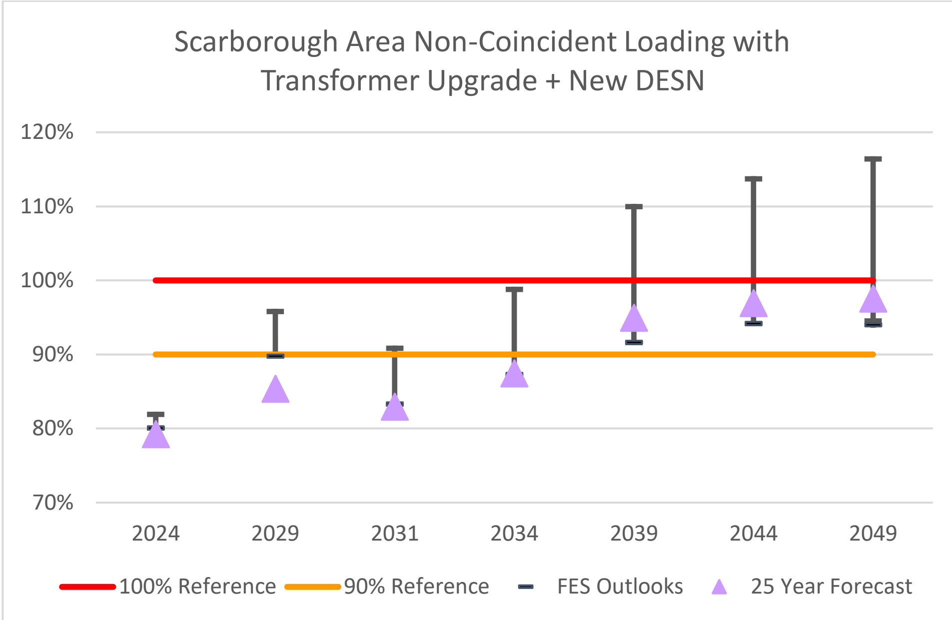


Figure 6 – Scarborough area Loading Following New DESN

The scope of work involved will be similar to the expansion project recently completed at Horner TS in 2022. As Scarborough TS is a Hydro One-owned station like Horner TS, Hydro One will complete the entire scope of work, involving: clearing space for the new DESN within or around the existing station, installing two new 125 MVA power transformers, installing a new gas-insulated switchgear and feeder tie switches, constructing a new building for the switchgear and control equipment, and connecting the transformers to Hydro One transmission lines. The total cost in Hydro One Contributions is estimated to be $56.3 million with a project timeline of 6 years, based on the experience of the Horner TS expansion. The start date would be Q1 2025 with an in-service date of Q4 2030. The annual estimated Hydro One Contributions are provided in Figure 7.

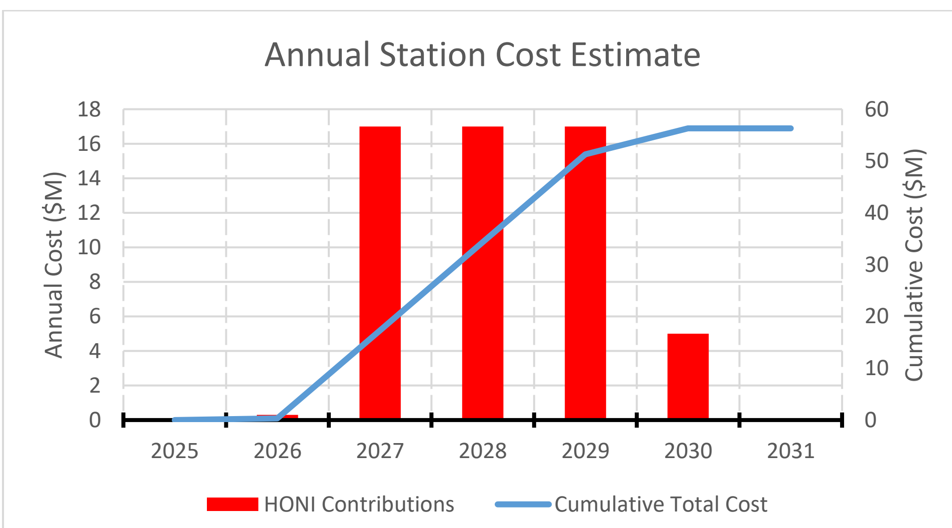


Figure 7 – Estimated Annual Hydro One Contributions for new DESN at Scarborough TS

From the perspective of high-level estimating, the scope of work to expand either Scarborough TS or Warden TS is estimated to be the same. As a result, the high-level cost estimate for both options is also the same at this time. Likewise, as shown in Figure 8, the quantity of load transfers required after expanding either station is estimated to be similar.

However, based on local geography, Warden TS is expected to face significantly higher execution challenges and costs in station egressing[6] than Scarborough TS. Additionally, the transmission corridor to Warden TS consists of a run of single transmission towers, which carry both of the station's transmission line supplies. This places a higher reliability risk at Warden TS, since the collapse of any tower along the corridor will result in a sustained outage to the entire station. Last, Scarborough TS is located central to the Scarborough TS area, which permits it to readily offload any station in the area. For these reasons, Scarborough TS was selected for expansion, rather than Warden TS.

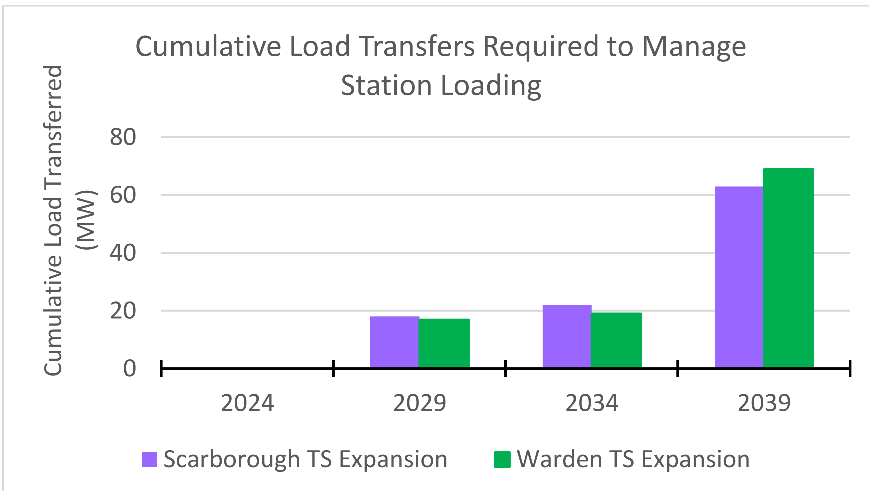


Figure 8 – Cumulative Load Transfers Required[7] for Each Expansion option

In conclusion, this option presents a feasible solution by introducing 133 MW of new capacity to the Scarborough area from a new DESN and a transformer upgrade at Scarborough TS. These investments are expected to bring the area loading down to 90 percent until 2036. This option also includes the provision for further expansion by an additional 95 MW, which when pursued will maintain area loading below 90 percent until 2042. The total cost of this option is estimated to be $56.7 million[8] with attainment in Q4 2030. In addition to expansion work, approximately 63 MW in load transfers will be needed over the 2025-2039 to manage the area.

[6] Station egressing includes the first portion of civil and electrical infrastructure between the Hydro One-owned station assets and THESL larger distribution system. This typically involves feeder cable trunks, large duct banks and cable chambers which run out of the station, and/or groups of overhead poles which run out of the station.
[7] Required to maintain station loading at or below 90%, or at the Area loading if the Area is loaded beyond 90%
8 The total cost of $56.7 million includes both the cost of the transformer upgrade ($0.4 million) and the cost of the new DESN ($56.3 million). Total cost has been used for the sake of fair option comparison.

4.6 Option 6: New Station ("TS")

This option considers the construction of a new transformer station ("TS") within the Scarborough area, in order to introduce new capacity and provide load relief. Because the station will be newly constructed, it can be situated to facilitate the offloading of adjacent stations and/or the connection of new loads.

In particular, this option proposes to build a new TS, located close to both the Golden Mile area and Warden TS, to address the new load and provide relief. The new TS would include the same electrical assets as the previous option 5: New DESN(s), and therefore will also introduce 95 MW of new capacity to the area.

The cost of building a new TS is estimated to be between $150-200 million and the time required is projected to take a minimum of 8 years. These estimates were developed based on past station expansion projects at Horner TS and Runnymede TS, and Toronto Hydro's experience in estimating its proposed Downsview TS project.

Since this option provides the same benefits as option 5: New DESN(s), but at a much higher cost, lead time, and execution risk, this option was not considered further.

5 OPTION ANALYSIS AND RECOMMENDATION

The key outcomes of the options presented are summarized in Table 7. options were considered in order of increasing level of intervention, until an acceptable option was identified. This ultimately led to the identification of the proposed option, option 5 – New DESN(s), as the option capable of meeting system needs with the least cost and risk.

Table 7 – Summary of Options Outcomes

Option (Increasing in Level of Intervention)	Decision	Reason for Decision	Decision Criteria				
			Acceptable Solution Outside of Short Term	Cumulative Load Transfers or NWSs Required [by 2039 or Earlier] (MW)[9]	Operational + Customer Connection Risks	Execution Risk	Risk of Subsequent Overloading
1 – Status Quo	Reject	This option is only viable as a short-term interim solution while a long term solution is in progress.	No	N/A – viable only in short term	High	Medium	Forecasted Overload
2 – Load Transfers	Reject	This option can only manage loading until 2029.	No	N/A – viable only in short term	Low	Minimal	Forecasted Overload
3 – NWSs	Reject	NWSs are not designed to be long term solutions. Very high execution risk due to unprecedented quantity of NWSs needed.	No	179	High	Very High	Mitigated
4 – Station Upgrades	Reject	This option can only manage loading until 2030.	No	30	Minimal	Minimal	Forecasted Overload
5 – New DESN(s)	**Accept**	Meets system needs with reasonable risks and quantity of load transfers.	Yes	63	Minimal	Medium	Mitigated
6 – New TS	Reject	This option carries excessive costs, lead time, and risks in comparison to option 5.	Yes	68	Minimal	High	Mitigated

[9] Load relief (as load transfers or NWAs) required past 2039 is not considered in this Options Comparison, since the Downsview Area is forecasted to exceed 90% loading again in 2036, given Options 5 or 6. At that point, additional new capacity may be considered rather than additional load transfers or NWAs.

Option 1 – Status Quo, as mentioned in Section 4.1, is never recommended when capacity constraints are identified, but illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress. Since this option is only viable in the short term, it was rejected. Similarly, the analysis for option 2 – Load Transfers showed that the option is only viable up until 2029, and as a result it was also rejected.

Option 3 – NWSs would be required indefinitely and would require an unprecedented quantity of load to be addressed, 179 MW. As mentioned in Non-Wires Solutions Program Narrative E7.2.1.1, NWSs are "designed to help address short-to-medium term capacity constraints", and are not designed to be long term solutions. Moreover, Toronto Hydro's NWSs over 2015-2019 have targeted a maximum of 10 MW, and the Program over 2025-2029 proposes a maximum target of 30 MW (see E7.2.1.4). As a result, a target of 179 MW by 2039 is highly unprecedented which translates into a very high execution risk. Therefore, because it is not designed to be a long-term solution and because of its very high execution risk, this option was rejected.

Option 4 – Station Upgrades was considered, but this option is capable of meeting system needs only up to 2030. Starting 2031, another solution would already need to be in place, and consequently that solution must be initiated in the 2025-2029 period. Therefore, this option was rejected.

Option 5 – New DESN(s) was considered for each of the 4 existing stations within the Scarborough area; but as mentioned in Section 4.5, Scarborough TS is the preferred candidate due to location and reliability of transmission supply. A new DESN at Scarborough TS, in combination with a transformer upgrade already underway due to Hydro One sustainment work, will provide the Scarborough area with 133 MW of new capacity by 2030 with a provision to install a second DESN when needed. These investments will meet system needs until 2036, and the installation of a second DESN will provide sufficient capacity to continue to meet system needs until 2042. A moderate quantity of load transfers (or NWSs in-combination) of 63 MW over 2025-2039 will be needed to effectively address the needs of each station. Therefore, since this option meets system needs with the least level of intervention (resulting in least cost, lead time, and risk), Toronto Hydro selected option 5 – New DESN(s) as the only reasonable solution to address capacity needs within the Scarborough area.

Option 6 – New TS was considered for the sake of assessing a complete options analysis, despite the feasibility of option 5 – New DESN(s). This option would provide the same benefit as option 5, but with: approximately 3-4 times the cost, a minimum 2-year increase in an already long lead time, and a much higher execution risk due to the need to site and supply a new TS. Therefore, this option was rejected in favour of option 5.

In conclusion, Toronto Hydro selected option 5 – New DESN(s) as the only reasonable solution to address capacity needs within the Scarborough area. Toronto Hydro proposes to implement option 5 with its Scarborough TS Expansion Project included in its 2025-2029 Rate Application, E7.4 Stations Expansion Program.

6 CONCLUSION

Toronto Hydro has identified a need for additional capacity within the Scarborough area due to forecasted high station loading in the medium term, and forecasted area overloading in the long term from the Golden Mile Secondary Development Plan (“GMSDP”).

To address this need, Toronto Hydro has considered multiple options including: Status Quo, Load Transfers, NWSs, Station Upgrades, New DESN(s), and New TS.

When considering short-to-long term needs, project costs, risks, and secondary benefits, Toronto Hydro concluded that its option 5 – New DESN(s) is the only reasonable option which addresses system needs.

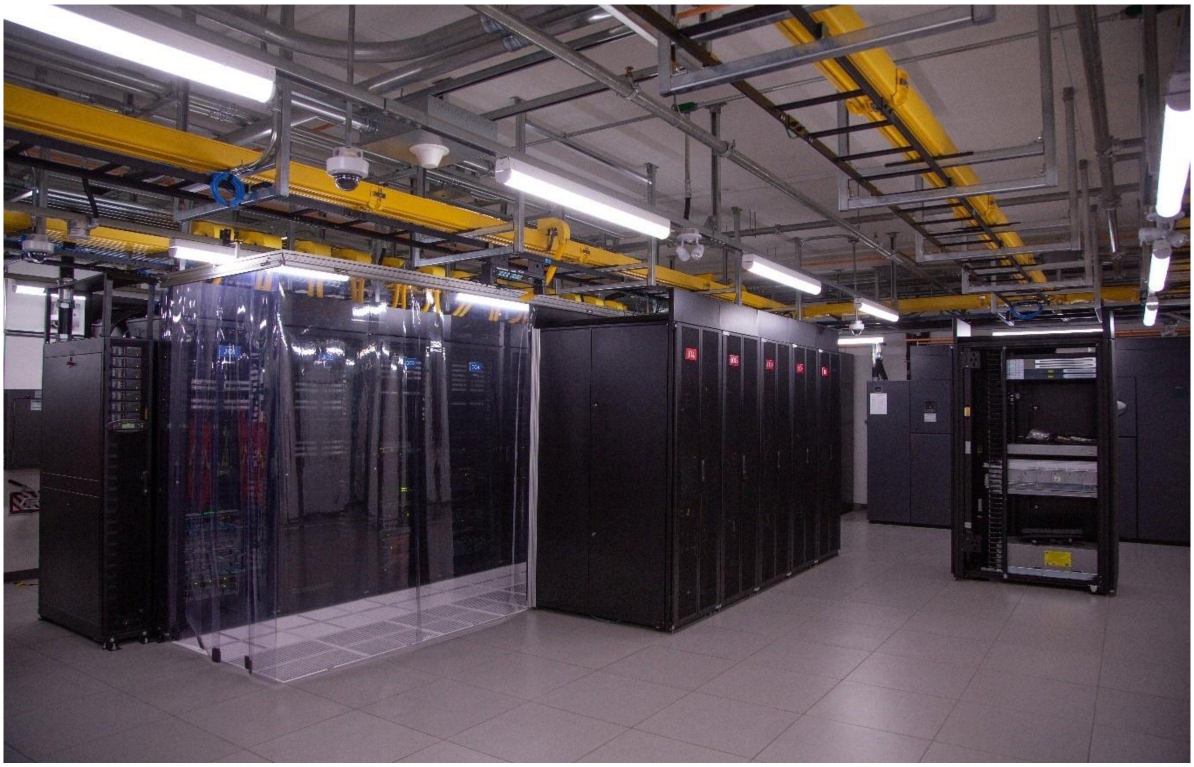
The recommended option will include an upgrade of the T23 transformer at Scarborough TS, and the installation of a new DESN at Scarborough TS. Forecasted completion is Q4 2028 and Q4 2030 respectively, and will provide 38 MW and 95 MW of new capacity respectively. The cost to upgrade the transformer is estimated to be $0.4 M, and the cost to construct the new DESN is estimated to be $56.3 M.

To manage station loading in the area, an estimated 18 MW, 4 MW, and 41 MW in load transfers or NWS capacity will be needed, respectively, in the following rate periods: 2025-2029, 2030-2034, and 2035-2039.

The new DESN proposed will be constructed with a provision to install a second 95 MW DESN when needed in the future, which will address the risk of subsequent high loading or overloading. Despite the proposed investments, the 25 Year Forecast forecasts 90 percent loading to reoccur after 2035, and the FES projections project overloading to occur as early as 2035.

The proposed investments will address upcoming high loading in the Scarborough area, support the City of Toronto’s Golden Mile Secondary Development Plan, and prepare the area to support electrification over the next 5-20 years.

E8.1 Enterprise Data Centre ("EDC") Relocation



E8.1.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): N/A	**2025-2029 Cost ($M):** $72.0
Segments: Facilities	
Trigger Driver: Operational Resilience	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Environment, Customer Focus, Financial Performance	

Toronto Hydro's 24/7 operations are supported by its Enterprise Data Centre ("EDC"), which houses the utility's essential networking, telephony and telecommunications systems, data storage and backup systems, and server infrastructure across two distinct locations ("centres") that collectively support the following organization-wide ("enterprise") processes ("data"):

- Control centre operations, including real-time control of Toronto Hydro's distribution system through supervisory control and data acquisition ("SCADA"), and remote monitoring and operation of substations and in-field devices;
- Grid management and response, including outage management, isolation and restoration activities, and radio communications with field personnel;
- Delivery of planned investments, including capital and maintenance activities;
- Asset management activities, including system planning, analytics and decision-making, and regulatory reporting functions;
- Financial activities, including capital budgeting and financial reporting;
- Engineering activities, including design, cost estimation, and job scheduling;
- Customer services, including customer care and billing, call centre operations, meter reading, meter data management and customer communications; and,
- Information technology ("IT") services, including IT systems and software, technical support services, office phone systems, and online services.

Figure 1 illustrates the foundational role that the EDC plays within Toronto Hydro, and how a failure of this physical infrastructure could result in an organization-wide outage impacting all enterprise processes.

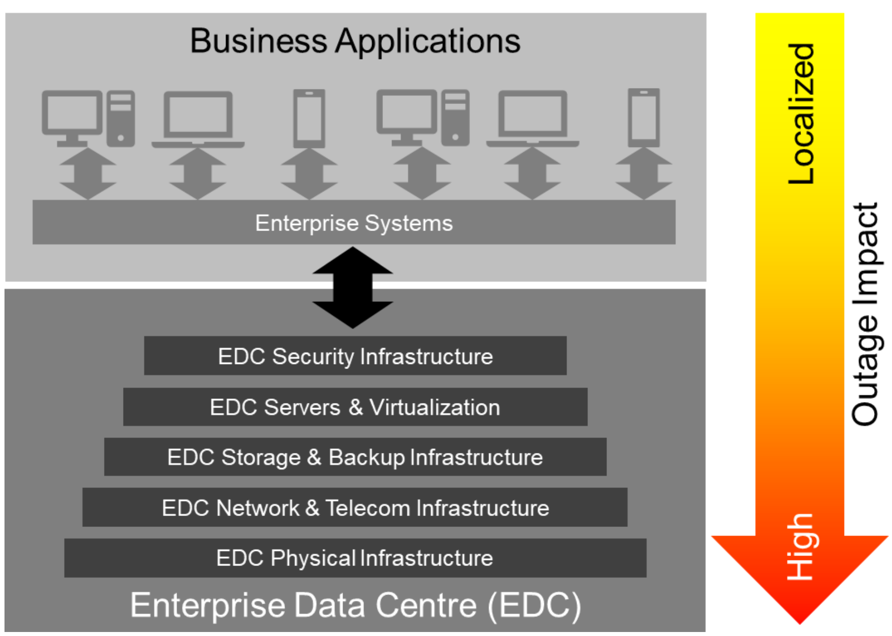


Figure 1: EDC and Supported Business Applications

An organization-wide outage would immediately disrupt operational systems and processes within Toronto Hydro's Control Centre Operations program, because power system controllers would be unable to access any real-time or near-real-time data within the Advanced Distribution Management System ("ADMS"), Outage Management System ("OMS") or Supervisory Control & Data Acquisition ("SCADA") systems.[1] Planned and unplanned activities within the utility's distribution system would suffer immediate disruption due to the loss of communication between the control centre and field crews, meaning that isolation, sectionalisation, and restoration activities would no longer be performed safely or effectively, resulting in extended outages to customers and significant delays in planned construction activities.

To better safeguard Toronto Hydro and its customers against the severe and significant impacts that an organization-wide outage could introduce, the EDC has been implemented across two physically separated locations for the purposes of providing redundancy and enhanced resiliency, should one or both EDC locations experience a normal or catastrophic failure event. Having multiple physically separated data centres is a common practice in the industry to enhance overall reliability, with recent surveys indicating that over 85 percent of organizations have three or more physically separated data centres in operation.[2] [redacted]

Toronto Hydro's EDC is facing emerging operational resilience, reliability, safety and security, and decarbonization issues specific to EDC 1 that require immediate intervention to mitigate the risks of a potential organization-wide outage. [redacted] 60 percent of the existing building infrastructure and facilities assets at EDC 1 are beyond their useful lives. Furthermore, Toronto Hydro has limited options to invest in necessary upgrades to building envelope systems at EDC 1 that can help mitigate current EDC capacity constraints. These growing facilities-related challenges are contributing to increased reliability risks for the EDC, including water damage, flooding, and physical safety and security risks that, if realized, would require the EDC to

[1] Exhibit 4, Tab 2, Schedule 7.
[2] See e.g. E. Thorne, "Corporate Data Center Geography, Explained", TeleGeography Blog, 2021, https://blog.telegeography.com/corporate-data-center-geography-explained

shut down. Finally, although Toronto Hydro estimates that it can fully meet its decarbonization goals with respect to the [redacted] Current energy efficiency goals as established by the Building Owners & Managers Association ("BOMA") and Energy Star are simply unfeasible to achieve within the EDC 1.

As Toronto Hydro continues to build, maintain, and operate its distribution system in accordance with the evolving needs and nature of load customers, distributed energy resource ("DER") owners and operators, and other stakeholders, it will aim to modernize its infrastructure and practices by introducing new enterprise systems and business processes throughout the 2025-2029 rate period. In other words, the EDCs will need to continue to grow to consistently meet the utility's, and by extension, its customers' needs. Although Toronto Hydro has prudently managed and maintained reliability and operational resilience within both EDC locations through its robust asset management strategy and asset renewal and repair activities,[4] the utility expects that EDC 1 will reach its capacity within the next five years and will no longer be able to accommodate new data and support new systems. Once this capacity threshold is reached, EDC 1 will no longer provide 1:1 redundancy to EDC 2. Under such a scenario, there will be a partial loss of business applications across the organization.

EDC 1 suffers from additional risks due to its limited and restricted footprint within the [redacted] which could increase the overall probability of an EDC failure event. For example, EDC 1 will continue to require at least two to three shutdowns per year to allow for the execution of necessary and essential facilities operations and maintenance activities aiming to safeguard the integrity of the location. Should EDC 2 fail during a shutdown of EDC 1, or should both EDC locations be impacted by a single event, an organization-wide outage will occur.

The EDC Relocation program (the "Program") proposes to relocate EDC 1 to [redacted] to enhance the overall redundancy and resiliency of the EDC and minimize the risks of an organization-wide outage. Through this relocation, Toronto Hydro will also be able to mitigate risks associated with operational resiliency, reliability, safety and security, and decarbonization. Subsection E8.1.2.1 on page 6 provides further details on the proposed investments within this

[3] [redacted]

[4] Respectively discussed under Exhibit 2B, Sections D5 (Facilities Asset Management Strategy) and E8.2 (Facilities Management and Security), and Exhibit 4, Tab 2, Schedule 14 (Facilities Management OM&A program).

program, while subsection E8.1.2.2 on page 15 provides further details on the key drivers and risks to be mitigated through the execution of this program.

E8.1.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's reliability and resiliency objectives by: ○ Reducing the risk of an organization-wide outage due to EDC failure; ○ Maintaining critical business applications, including control centre functions, grid management and response, planning and engineering, customer care and billing, and project execution; ○ Mitigating current reliability challenges due to the constraints and external factors at EDC 1; and ○ Enhancing the geographic diversity of the EDC to create redundancy and mitigate the risk of failure by reliance on a single EDC facility.
Operational Effectiveness - Safety	Contributes to Toronto Hydro's safety objectives by: • Mitigating health and safety hazards from building infrastructure deterioration at EDC 1 (raised floor, windows, life safety infrastructure and fire suppression); and • Providing safe access to the relocated EDC for deliveries and during the loading/unloading of components.
Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Allowing for customer service and call centre operations to continue uninterrupted in the event that one of the EDCs fail and minimizing the risks of potential call centre outages; and ○ Mitigating the risks of an organization-wide outage that can result in the extension of outages to customers.
Environment	• Contributes to Toronto Hydro's environmental objectives by: ○ Assisting with the achievement of goals outlined in Toronto Hydro's Net Zero 2040 Strategy by reducing scope 1 greenhouse gas emissions; and ○ Leveraging energy efficient HVAC and lightning systems.

Financial Performance	• Contributes to Toronto Hydro's financial performance objectives as measured by the total cost and efficiency measures by: ○ Reducing capital costs by sharing existing infrastructure at the proposed EDC including cabling pathways, physical security, access control, and power redundancy solutions; and ○ Leveraging an existing fiber-optic connection between EDC 2 and the proposed EDC to reduce project costs.

E8.1.2.1 Program Description

This program proposes the relocation of EDC 1 to the [redacted] Toronto Hydro will require $72 million over the 2025-2029 rate period to execute and complete this program.

The utility proposes the [redacted] as the optimal relocation site for the following reasons:

- [redacted] and
- Existing Fibre-Optic Connections and Footprint: The proposed EDC contains a fibre-optic connection with EDC 2, which would enable the transfer of data and communications from the [redacted], thereby reducing overall project costs when compared to other potential locations. The proposed EDC also provides a [redacted] square feet footprint, which is necessary for housing all EDC assets.

Further details regarding the various relocation options and how the utility determined the optimal relocation site are provided in subsection E8.1.4 on page 23.

The proposed EDC will be a [redacted] to the existing warehouse area within the [redacted] and the EDC will be located [redacted] A total of [redacted] square feet of space will be dedicated to house the following key components:

[5] From the completion of the Control Operations Reinforcement program in Exhibit 2B, Section E8.1 of Toronto Hydro's 2020-2024 Custom Incentive Rate Application (EB-2018-0165). See also Exhibit 2B, Section E4 of this application.

- Physical Infrastructure: Provides the necessary vertical and horizontal space requirements to load, test and integrate, and store core assets within the proposed EDC. This includes the data hall, staging area, access trap, and loading dock;
- Electrical Infrastructure: Powers the EDC and provides redundancy should a localized failure at the proposed EDC occur. This includes the electrical supply points, uninterruptible power supply ("UPS"), and generators;
- Environmental Infrastructure: Maintains optimal environmental conditions within the EDC, while also providing essential protection against threats such as fires. This includes the HVAC and fire suppression systems;
- Telecom Infrastructure: Connects the EDC to Toronto Hydro's Control Centres, work sites, offices, substations and distribution system components;
- Network Infrastructure: Facilitates communications between servers, storage, and applications;
- Storage and Backup Infrastructure: Provides centralized storage of all production, test, and development data for online access and long-term archival;
- Computing Resources: Includes the servers, which provide the necessary processing, memory, virtualization, and connectivity to support business applications and associated middleware/database components; and
- Security Infrastructure: Enables physical and cyber security controls to sufficiently protect assets contained within the EDC.

The Program aims to retire the existing assets and infrastructure at EDC 1, while supporting Toronto Hydro's continued efforts to modernize its operational systems. The execution of the Program will ensure that Toronto Hydro's EDC continues to withstand evolving hazards and threats, thereby allowing the utility to continue operations and provide customer services, effectively safeguard, manage, and operate its distribution system, minimize potential safety hazards to the public and employees, and minimize business interruption impacts on its customers as efficiently and effectively as possible. The following subsections provide further details on the various components as specified above.

Figure 2 illustrates key components within the proposed EDC and its relation to the broader [redacted] all components of the proposed EDC will be secured with [redacted]

[redacted]

1. Physical Infrastructure

To further enhance the resiliency and reliability of the EDC 2 and EDC 1 locations, Toronto Hydro has aligned these locations to the requirements established by the Uptime Institute within its Tier Classification System.[6] EDC 1, [redacted], aligns to Tier I requirements within this classification system and cannot be further enhanced to align to Tier II or Tier III requirements, due to the lack of available space, electrical supply, environmental conditions, and installed redundancy within EDC 1.

With the increased space availability at the location for the proposed EDC, it will be possible for Toronto Hydro to align the proposed EDC with Tier III requirements, meaning that the EDC will be more reliable than the existing EDC 1 and EDC 2 locations by several orders of magnitude, with completely redundant components. Despite the enhanced Tier III functionalities, the utility will build the proposed EDC at a cost that remains proportional to the up-front costs for EDC 2.

[6] Uptime Institute, Tier Classification System https://uptimeinstitute.com/tiers. A higher tier indicates more sophisticated standards and controls and thus, greater expected reliability.

Key physical infrastructure components within the proposed EDC will include the following:

[redacted]

[redacted]

The increased size of the proposed EDC data hall allows for expanded corridors between EDC assets and provides enhanced physical capacity to install additional equipment in the future. For illustrative purposes, the physical capacity of EDC 2 is shown in Figure 3. By comparison, EDC 1's data hall is already at physical capacity and adding additional infrastructure would require significant reconfiguration of the existing EDC assets.

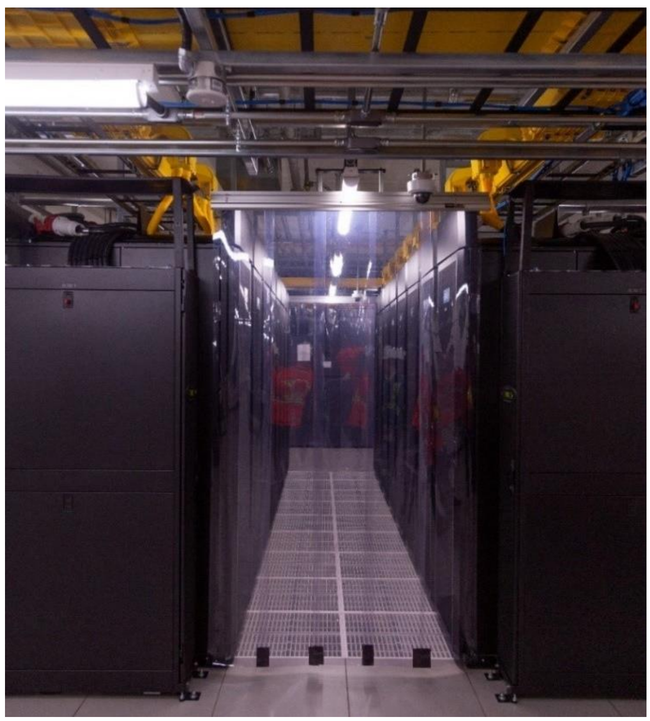


Figure 3: Available Physical Capacity at EDC 2

[7] "ANSI/TIA-942A 2012 Telecommunications Infrastructure Standard for Data Centers", Telecommunications Industry Association, 2012.

2. Electrical Infrastructure

The proposed EDC will have its own dedicated electrical supply points, along with dedicated electrical rooms, UPS and generators. A dedicated 1.25 megavolt-amperes substation will provide power distribution into the EDC. Two dedicated 1.0-megawatt generators will provide enhanced redundancy should an electrical supply failure or upstream outage occur. The dedicated supply points will allow the proposed EDC to remain unaffected by any facilities operations or maintenance activities taking place within [redacted]

Two 550 kilovolt-ampere modular UPS systems will serve the proposed EDC, with each system providing enhanced redundancy, while also being within the secure access perimeter. The size of these UPS systems will be to enable continued growth and allow the proposed EDC to maintain 1:1 redundancy with EDC 2.

3. Mechanical / HVAC Infrastructure

The proposed EDC will contain an advanced HVAC system designed to provide optimal cooling to the overall EDC environment and contained assets. A 24-inch raised floor system will be installed to provide efficient cold air flow panels with flow management capabilities for 20 network cabinets and 64 server equipment cabinets. This HVAC system will leverage free cooling technology to deliver reliable cooling at reduced energy costs when compared to the existing EDC 1. Only the cooling system will be installed within the raised floor system to maximize underfloor space, while the electrical supply will feed EDC equipment from overhead. For illustrative purposes, the underfloor capacity at EDC 2 is shown in Figure 4.

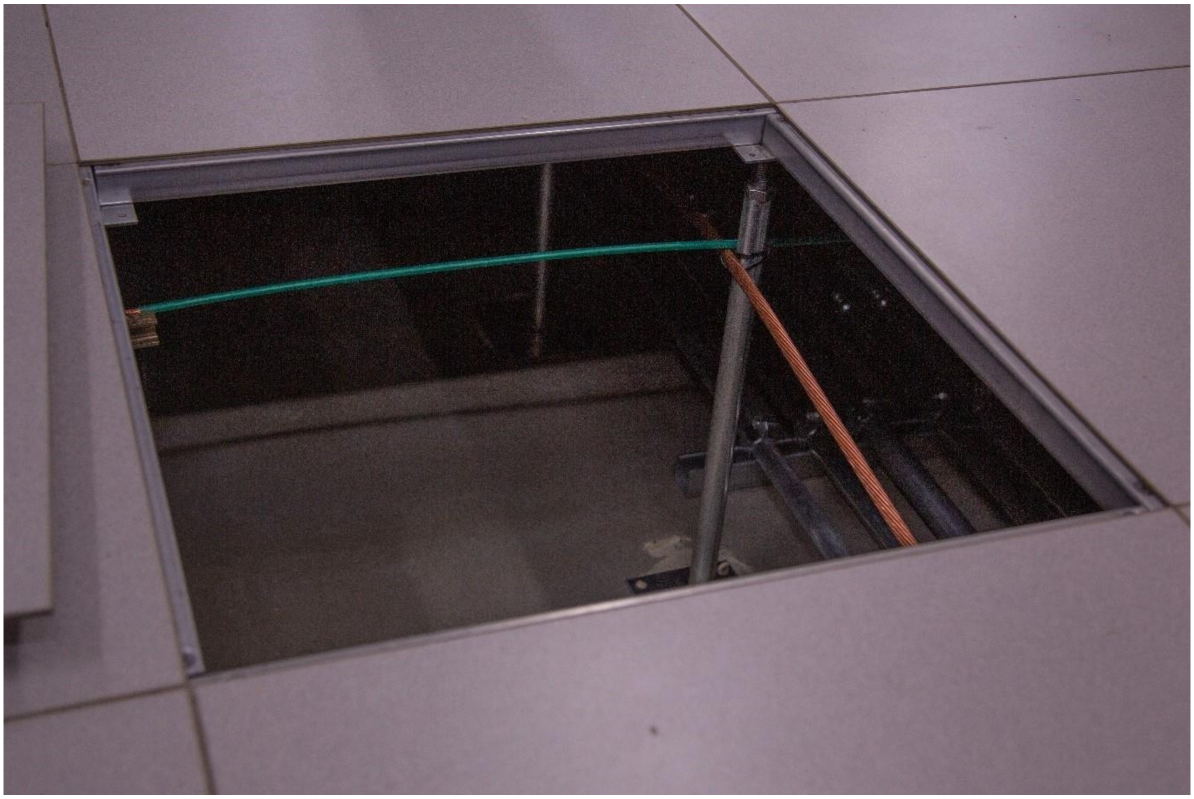


Figure 4: Available Underfloor Capacity at EDC 2

Two CRAC units will be installed within their own dedicated gallery rooms. These units will be stand-alone from the HVAC system and designed to provide redundancy within the proposed EDC. By comparison, the CRAC units within the current EDC 1 are installed directly within the data hall and do not provide redundancy, meaning that if the system fails, there is no backup cooling units available, which may cause the temperature of EDC hardware to increase beyond safe operation limits and result in equipment failure.

An advanced pre-action fire suppression system with sprinkler piping and heads, along with a clean agent gas fire suppression system will be installed within its own dedicated area to provide multi-zone protection within the proposed EDC, including the data hall, CRAC galleries and, electrical rooms.

4. Telecom Infrastructure

The proposed EDC already possesses a fibre-optic connection EDC 2, enabling continuous communications between these two facilities and thereby supporting the 1:1 redundancy across the

EDC. This fibre-optic connection is [redacted], and therefore aligned with industry standards of ten to 50 miles to provide replication data integrity and operational efficiency. By leveraging this existing connection, Toronto Hydro can reduce overall program costs.

5. Network Infrastructure

Network infrastructure within the proposed EDC will be designed to enhance overall disaster recovery ("DR") and reliability by improving end-to-end fault-tolerance architecture, modular redundancy, operational performance, reliability, and availability of enterprise physical Infrastructure. The network infrastructure will be configured to enhance overall scalability capabilities by featuring an optimized architecture designed from the ground up with flexibility and scalability to support the utility's evolving needs.

6. Storage and Backup Infrastructure

All storage and backup infrastructure within the proposed EDC will be on-premises, thereby allowing for data to be retrieved quickly, while allowing compliance with applicable data sovereignty and legislative and regulatory requirements.

7. Computing Resources

All computing resources will be modernized such that they are dynamic and capable of enabling physical connectivity in a scalable manner. Resources will be monitored via real-time monitoring technologies to measure overall performance and respond to emerging risks.

8. Security Infrastructure

The security infrastructure of the proposed EDC will consist of an enhanced security perimeter containing all EDC infrastructure, including the dedicated electrical room, UPS, generators, data hall, staging area, access trap and loading dock, thereby reducing potential safety and security risks.

To enhance overall physical security and control access within the proposed EDC, a multi-step entry system with limited entry points will be configured. EDC access will be based upon dual authentication through card readers and keypads. Access into the data hall, CRAC galleries, staging room, and electrical room will be based upon the card reader system. Access control will be further enhanced via perimeter lighting, thermal cameras, a vehicle security station, and license plate recognition systems to enable employee and vehicle access, as well as incursion protection and video surveillance systems.

E8.1.2.2 Program Drivers

Table 3: Program Drivers

Trigger Drivers	Operational Resilience
Secondary Driver(s)	Reliability, Safety, Customer Service, Decarbonization, Financial

1. Operational Resilience

Operational resilience is the primary driver of Toronto Hydro's need to maintain dual EDCs in good condition. A failure of the EDC would result in the immediate interruption of services across the organization that rely on business applications, underlying data, and communication systems. This organization-wide outage, which would include catastrophic disruptions to the previously discussed business processes and operations, would impact overall operational resilience across the organization as further discussed below.

[redacted] As Toronto Hydro's business and operations continue to evolve, the EDC will require more physical and electrical capacity to store and manage more data and to support more enterprise systems and business processes.

In the event of an organization-wide outage due to an EDC failure, the following impacts would immediately arise:

- Reliability impacts: Mission-critical applications that allow the utility to monitor and manage the distribution system, including ADMS and OMS systems would no longer function, eliminating any visibility of the grid. Outages that are already in progress or occur following an EDC failure would be extended indefinitely, until such time that the EDC can go back online;

- Safety impacts: Without visibility of the grid or functioning radio systems, power system controllers can no longer effectively monitor the system, manage planned and reactive outages, or communicate with field crews, giving way to potential safety risks to both crews and the public; and
- Customer service impacts: Toronto Hydro's meter data management ("MDM") systems, customer information system ("CIS") and telephone systems would be unable to function, impeding the meter-to-cash process and the ability of customer care personnel to manage customer service requests.

[redacted] For example, any high-impact renovation and construction projects aimed at improving the work centre assets would require the EDC space to be vacated during the renovations to avoid physical impacts upon EDC infrastructure and vice versa.

[redacted] Over the past five years, these risks and challenges have continued to increase in volume.

Table 4: [redacted] Condition Assessment Results

Item	Condition	Status
Roof	**Very Poor**	[redacted]
Stone Cladding	**Poor**	Performance depends on external conditions.
Windows	**Poor**	[redacted]
Heating & Cooling	**Fair**	Unreliable five-pipe system cannot be replaced without first vacating EDC 1.
Storm Water Piping	**Poor**	Aging stormwater piping must be replaced.
Domestic Water	**Poor**	Aged piping must be repaired.
Sanitary	**Poor**	Aged sanitary system must be repaired.
Electrical Distribution	**Very Poor**	[redacted]
Electrical Service	**Poor**	
Abatement	**Very Poor**	

Examples of asset condition issues within EDC 1 that cannot be resolved due to the risk of materially affecting the integrity of the EDC include the following:

- Building exterior, including masonry and façade issues arising from the [redacted] and deteriorating building envelope and water tightness;
- Deterioration of windows due to age and poor condition, leading to the risk of water infiltration; and
- An aging, unreliable, and corroding five-pipe heating and cooling system that cannot be replaced with a modern duct-based system due to lack of headroom clearance.

In some cases, even smaller initiatives can have larger and broader impacts on EDC 1. For example, shutdowns of EDC 1 were necessary when Toronto Hydro [redacted]

[redacted] This logistical complication increased the costs of installing the new stations.

As the location continues to age and the backlog of high-impact renovations and maintenance activities close to the EDC increase in volume, EDC 1 will impose significant challenges and restrictions in mitigating these asset risks, leading to higher overall costs due to the complexity, effort, and time needed to coordinate the execution of facilities operations and maintenance activities without materially impacting EDC operations. By deferring these high-impact renovations, the utility's operational resiliency will continue to deteriorate over the 2025-2029 rate period.

[redacted]

The previously discussed challenges, combined with the current footprint and asset configuration of the [redacted], render it impossible to upgrade EDC 1 to better align to Tier II or Tier III requirements. Even if Toronto Hydro were to attempt upgrades, it would have to take EDC 1 offline for a significant period of time. This would require all EDC operations to be solely supported by EDC 2 for the duration of the upgrades, which would eliminate the redundancy between the two EDC facilities and unacceptably increase the risk of an organization-wide outage.

2. Reliability

As previously illustrated in Figure 1, the EDC plays a foundational role in supporting all of Toronto Hydro's business applications and processes that are in operation 24/7, including control centre

[8] Uptime Institute, Tier Classification System https://uptimeinstitute.com/tiers. A higher tier indicates more sophisticated standards and controls and thus, greater expected reliability.

functions, grid management and response, planning and engineering, customer care and billing, and the execution of planned capital work across the distribution system.

A complete EDC failure would result in all of Toronto Hydro's business applications becoming unresponsive and non-functional. In the event of a distribution system outage, this would have cascading and substantial financial and economic impacts on customers within the City of Toronto—the largest city and economic centre of Canada, as well as fourth largest city in North America. During an organization-wide systems failure, customers would have no way of reporting distribution system outages or communicating with the utility due to the disruption to contact centre and communications channels. Due to power losses, commercial customers would face immediate revenue impacts as well as major disruptions to their business operations and harmful side effects, such as the potential spoilage of inventory goods and materials. Industrial customers without available backup systems would see immediate disruptions to their business (e.g. manufacturing) processes and even after power is restored, it would take time for these customers to return to full operations. Critical customers such as hospitals, water pumping stations, emergency management services, or transit operators such as the Toronto Transit Commission ("TTC") would also see immediate disruptions during an organization-wide outage event.

Another reliability factor informing the Program is that EDC 1 is expected to reach its electrical capacity within the next five years due to the limitations of the current UPS system. [redacted]

Finally, EDC resiliency is threatened by increasing vandalism, cyber and physical terrorist threats, and extreme weather event trends. A recently commissioned study conducted by the U.S. Department of Energy has shown an increasing trend since 2015 with respect to vandalism and extreme weather events that are impacting utility-owned infrastructure, as illustrated in Figure 5.[9] As extreme weather and vandalism events continue to grow, both in terms of magnitude as well as frequency [redacted]

[9] U.S. Department of Energy, Electric disturbance events (DOE-417), Archives https://www.oe.netl.doe.gov/oe417.aspx; Toronto Region Conservation Authority, Taking Action on Climate Change in Toronto Region https://trca.ca/climate-change-impacts-gta/

Relocating EDC functions to the proposed EDC will enhance geographic diversity and help mitigate the risk of a single point-of-failure due to an extreme weather, vandalism, or terrorist event.

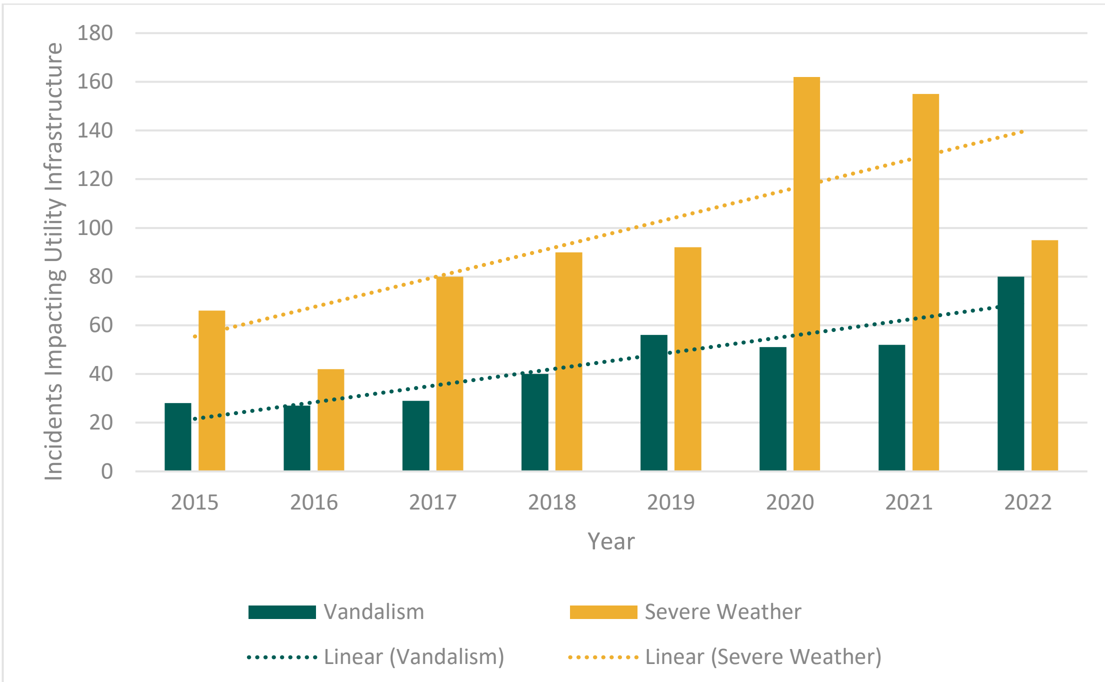


Figure 5: Severe Weather & Vandalism Incidents Impacting Utility Infrastructure

3. Safety & Security

Figure 6 illustrates the supporting systems for EDC 1 that currently reside outside of the secure access perimeter and within common areas of the [redacted] that are exposed to additional safety and security risks. There is also no dedicated or secure location for the storage of EDC assets and spare parts. Only one of Toronto Hydro's UPS units is located within the secure access perimeter of EDC [redacted] Furthermore, EDC 1 does not provide adequate physical capacity for components such as a loading dock, staging area, or access trap. For these reasons, EDC 1 remains exposed to considerable safety and security-related risks. By contrast, as illustrated by Figure 2, all [redacted] EDC components and functions would be fully secure within the secure access perimeter with two-factor authentication, such that only authorized persons can gain access.

[redacted]

4. Decarbonization

As outlined in the Net Zero 2040 Strategy, in Exhibit 2B, Section D7, Toronto Hydro plans to implement several initiatives throughout the 2025-2029 rate period and beyond to reduce the utility's scope 1 greenhouse gas emissions and achieve net zero by 2040. Although Toronto Hydro estimates that it can fully achieve its decarbonization goals for the [redacted], requiring the EDC space to be fully vacated and thus giving rise to the previously discussed risks. Current energy efficiency goals as established by the BOMA and Energy Star are not achievable within the [redacted]

5. Financial

Toronto Hydro's options analysis in section E8.1.4 on page 23 describes the criteria and requirements that the utility assessed to identify the optimal site for the proposed future location for the EDC in light of the high costs of asset management due to the continued risks, challenges, and constraints that are caused by the EDC 1.

E8.1.3 Expenditure Plan

The Program proposes to relocate the existing EDC infrastructure located at Toronto Hydro's EDC 1 to a new location within the proposed EDC to maintain the utility's operational capabilities and mitigate identified resiliency, reliability, safety and security, and decarbonization risks.

The proposed EDC meets all necessary pre-requisites for Toronto Hydro to align to Tier III data centre capabilities as defined by the Uptime Institute.[6] This includes establishing concurrently maintainable capabilities using redundant components and redundant power distribution paths. [redacted] Program costs can be significantly reduced by leveraging this existing connection.

Finally, the proposed EDC is located more than [redacted] away from EDC 2. This provides greater geographical diversity between the two locations, reducing the possibility for a single event (e.g. deliberate attacks, extreme weather) to simultaneously impact both locations at the same time.

Toronto Hydro requires $72 million over the 2025-2029 rate period to execute and complete the Program. This expenditure plan consists of four work categories, namely:

- Non-direct construction costs: Pre-construction planning and equipment expenditures;
- Alterations and demolitions: Costs associated with performing targeted demolitions and alterations within the proposed EDC to support the integration of the EDC;
- Building: Costs associated with facility upgrades needed to meet required standards; and
- Site works: Preparation of the area where the EDC will be constructed.

E8.1.3.1 Planned Project Timeline

The planned project timeline will take place within the 2025-2029 rate period. Planned work and non-direct construction costs will begin in 2025. The construction work will be phased out to minimize any overtime or premium costs and minimize disruptions to business operations. The estimated in-service date for the project is 2029.

E8.1.4 Options Analysis / Business Case Evaluation ("BCE")

Toronto Hydro has considered the following options to manage the current risks associated with the EDC, including:

- Status quo: Maintaining the EDC 1 and EDC 2 locations in their current state;
- Relocating all EDC functionality to EDC 2;
- Relocating EDC 1 to a non-Toronto Hydro-owned property; and
- Relocating EDC 1 to a Toronto Hydro-Owned Property.

E8.1.4.1 Option 1: Status Quo

The status quo option would entail continuing with the existing EDC 1 as it is configured today, with redundancy being maintained between EDC 1 and EDC 2.

Under this scenario, current risks relating to operational resiliency, reliability, safety and security, and decarbonization would remain in place. Toronto Hydro will be unable to further expand EDC 1, due to current vertical and horizontal footprint limitations and the [redacted] Consequently, EDC 1 will be unable to support a more advanced cooling system to support the introduction of higher density asset infrastructure. Without increases to the density of asset infrastructure, due the utility's reliance on the EDC to process increasing volumes of data and business processes, the UPS of EDC 1 will reach the limits of available capacity over the next five years. This would significantly reduce the efficiency of the UPS in providing sufficient backup power during an outage event and eliminate the 1:1 redundancy between the two EDC locations. In other words, in the event of a failure at EDC 2, EDC 1 could only support a finite number of business applications, meaning that the utility would suffer at least a partial systems outage and incur major business continuity risks.

As major systems within EDC 1 reach end-of-life, the asset management costs to replace or upgrade individual components will increase due to the limited footprint and [redacted] and the unique hazards it presents (such as the presence of asbestos), any cabling or electrical work may lead to delays, cost overruns, and overall higher replacement/upgrade costs.

Due to physical and electrical constraints, EDC 1 can never attain Tier II or Tier III data centre controls and therefore can never provide full redundancy should any of the EDC assets require maintenance or outright replacement. [redacted]

Finally, due to the geographical proximity of EDC 1 and 2, both locations and the EDC infrastructure contained within them could be impacted by a single extreme weather event, natural disaster, threat, or attack. In such a scenario, all functions supported by the EDC would be immediately and adversely impacted and result in operational disruptions and safety risks to Toronto Hydro personnel and potentially to the public. These risks would impede Toronto Hydro's ability to: (a) locate failed assets and affected parts of the distribution system; (b) perform the necessary system isolations to enable crews to safely perform repairs; (c) mobilize crews to affected locations within the system; and (d) remotely control distributed energy resources.

To sufficiently mitigate and manage risks within tolerance levels at EDC 1 while maintaining operations of the current EDC configuration, Toronto Hydro would need to spend approximately $110.4 million, making the status quo option the costliest for the utility.

E8.1.4.2 Option 2: Relocate All EDC Functionality to EDC 2

An alternative option would be to eliminate EDC 1 in favor of having a single EDC operating out of EDC 2. Under this option, Toronto Hydro would entirely shift EDC functionality to the EDC 2 location, which would eliminate the redundancy that currently exists by virtue of the utility's operation of two physically separate EDC locations.

This scenario would also increase Toronto Hydro's risk exposure, as a single disruptive event at the EDC 2 could potentially impact the entire EDC and result in an organization-wide systems outage. Although EDC 2 provides the necessary features and footprint to support continued growth of the EDC and enable the attainment of Tier II data centre controls, the lack of geographical redundancy would nonetheless significantly expose the utility to the risk of weather-related events, natural disasters, and deliberate threats.

As this scenario would leave the single EDC excessively vulnerable to a variety of risks and the costs to mitigate these potential risks would be too high, the utility does not consider this to be a feasible option.

E8.1.4.3 Option 3: Relocating EDC 1 to a Non-Toronto Hydro-Owned Property

In developing the Program, Toronto Hydro also assessed whether alternative real estate and construction configurations may result in greater cost savings. For example, one alternative would be the relocation of EDC 1 to a location outside the city of Toronto, where real estate costs are significantly lower. The utility further evaluated whether it would be feasible and cost-effective to replace the on-premises EDC 1 with an entirely cloud-based solution.

1. Relocating EDC 1 to a Location Outside of Toronto

Toronto Hydro assessed potential cost-saving opportunities from relocating EDC 1 to a location that is outside of Toronto, where real estate and development costs would be lower than in the city of Toronto.

The major challenge posed by this approach would be maintaining the 1:1 redundancy between the relocated EDC and EDC 2, which is currently achieved [redacted] at a location outside of Toronto Hydro's service area would be extremely costly, due to the larger distances required to secure this connection. These additional costs would likely offset any savings achieved in real estate and/or development costs. To install this [redacted], Toronto Hydro would also be required to coordinate with the utility that is managing the adjacent service area. This level of coordination and approval may result in greater project delays and cost overruns.

As the EDC directly supports all of Toronto Hydro's Control Centre functions, and as there are shared resources and infrastructure with respect to cabling pathways, physical security & access control solutions, as well as power redundancy solutions that can be extended to the proposed EDC location, there are enhanced benefits in moving the EDC [redacted].

Distance also becomes a key parameter in disaster response. For example, employees would have to travel large distances to potentially inaccessible locations to provide emergency and disaster responses. This is not safe or ultimately reliable for employees. When considering these constraints as well as the additional costs, this option is not considered to be feasible or viable for Toronto Hydro.

2. Development of a Cloud-Based Control Operations Systems Centre

Toronto Hydro's EDC 1 is [redacted]

As discussed in Toronto Hydro's Information Technology Asset Management and Investment Planning Strategy in Exhibit 2B, Section D8, the availability of cloud-based solutions, where a third-party provider can manage the servers and perform the maintenance and security updates supporting a business function or software platform, is steadily increasing. Cloud-based solutions are also available in the form of "private clouds", where all cloud computing resources remain exclusive to a single client. However, the cost structure of cloud-based data centre hosting would be significantly different than implementing an [redacted], as vendors typically charge for cloud solutions on an ongoing, monthly basis. In other words, the implementation of a cloud solution would introduce new operational, maintenance, and administrative ("OM&A") costs for Toronto Hydro that over time would exceed the up-front capital expenditures that are proposed under this program and reduce the cost effectiveness of this option.

Furthermore, the implementation of a cloud-based solution—even a "private" one—would introduce several reliability or operational risks that would not exist under an on-premises solution. Toronto Hydro would have to rely upon its vendor(s) to manage the reliability of the cloud-based environment or restore functionality after planned downtimes or unplanned outages, in contrast to an [redacted]. This would increase reliability and business continuity risks with respect to the critical functions performed by the EDC. Many of the business applications supported by the EDC, particularly those that are critical for Control Centre Operations,[10] would be better served by an [redacted] that would better meet the latency and communications parameters required for the underlying functions.

In addition, several traditional hard-wired components that are directly supporting the EDC and its connectivity with the field asset infrastructure, including fibre-optic connections, would not be

[10] Exhibit 4, Tab 2, Schedule 7.

compatible with cloud-based services. Given the collective risks presented by the above factors, Toronto Hydro determined that a cloud-based solution would not be feasible option.

E8.1.4.4 Option 4: Shifting EDC 1 to a Toronto Hydro-Owned Property

The fourth and final option involves relocating EDC 1 to an existing property already owned and operated by Toronto Hydro and within Toronto Hydro's service area. Relocating EDC 1 to an alternative Toronto Hydro location would introduce cost savings by utilizing existing footprints and building systems in place. The subsequent sub-sections will individually examine potentially viable locations to assess the feasibility of relocating the EDC functions.

3. Relocating EDC 1 to [redacted]

Toronto Hydro's operations [redacted] Unlike the proposed EDC, the [redacted] does not possess the necessary square footage to house all EDC assets. In addition, there is no current fiber-optic connection with EDC 2, to maintain the 1:1 redundancy between the EDC locations. While a fiber-optic connection can be installed between these two locations, it would considerably raise the overall costs for the program. As the EDC directly supports all of Toronto Hydro's Control Centre functions, and as there are [redacted], there are enhanced benefits in keeping both EDC locations close to the existing Control Centre facilities [redacted] For these reasons, the [redacted] is not considered to be a prudent, cost-effective option.

4. Relocating EDC 1 to the Proposed EDC (Selected Option)

Toronto Hydro's operations [redacted]. As is the case with the [redacted] the proposed EDC has the necessary footprint and characteristics to support the development of a Tier III data center solution, as defined by the Uptime Institute. As there are cost-savings opportunities by leveraging shared resources and infra structure, including cabling pathways, physical security & access control solutions as well as power redundancy solutions that can be extended to the proposed EDC location, there are en hanced benefits in moving the EDC to [redacted]

Cost savings are further achieved as the proposed EDC [redacted], which is needed to maintain 1:1 redundancy between the two EDC locations. This current-state connection is further illustrated in Figure 7. The [redacted] possesses a total of [redacted] square feet of space to accommodate a fully functioning EDC with all required assets. Ultimately, when taking into consideration costs, footprint and building characteristics, [redacted] remains the sole option that meets all requirements and cost considerations.

[redacted]

E8.1.4.5 Evaluation of Options

Toronto Hydro selected a set of evaluation criteria to compare each available option, and identify the most optimal, cost-effective, and prudent option for this program. Evaluation criteria included the following:

- Environment (humidity, moisture/condensation, extreme floods, ice storms, etc.);
- Space for EDC footprint;
- Space for EDC generators;
- Prerequisites to meet Tier III requirements as defined by Uptime Institute;
- Geographic diversity (the longer the distance between the two EDC locations, the better);

[redacted]

- Proximity to Existing Control Centre; and
- Total Cost Impact to Ratepayers.

Each of the above criteria were taken into consideration when selecting the best overall option for Toronto Hydro.

Figure 8 illustrates the results of the options analysis, comparison, and final recommendations, based upon what has already been discussed for each of the options above.

	Back Up Data Centre Parameters						
Options	*Optimal Environment*	*Proximity From EDC*	*Space for EDC*	*Space for Generators*	*Tier III*	*Existing Fiber Optic*	*Proximity From Control Centre*
Locate Outside of Toronto	🟡	🔴	🟡	🟡	🟡	🔴	🔴
Cloud-Based DC	🔴	🔴	🔴	🔴	🔴	🔴	🔴
[redacted]	🔴	🔴	🔴	🔴	🔴	🟢	🔴
[redacted]	🔴	🔴	🔴/🟡	🟢/🟡	🔴	🟢	🟢
[redacted]	🟢	🟢	🟢	🟢	🟢	🔴	🔴/🟡
[redacted]	🟢	🟢	🟢	🟢	🟢	🟢	🟢

🔴 Goal Not Attainable 🟡 Goal Potential/ Partial 🟢 Goal Attainable

Figure 8: Results of Option Analysis

When assessing current-state risks, availability of space and technological capabilities, costs, as well as overall ability to meet the current and future objectives for the EDC, this comparison indicates that the relocation of EDC 1 to the proposed EDC satisfies all the criteria. Ultimately, relocating the EDC to the proposed location is the most effective and prudent solution to satisfy all requirements for this program.

E8.1.5 Execution Risks & Mitigation

The largest risk to the successful execution of the Program involves timing and costs. Material costs are generally subject to greater price fluctuations over time and therefore cost overruns may transpire. However, through the expertise of experienced project management leadership and industry experts, a proactive approach will be taken to manage these costs.

In addition, there are also construction related risks associated with the Program, including:

- Unexpected construction conditions;
- Occupational health and safety;
- Disruption to Toronto Hydro employees at [redacted];
- Design change approvals;
- Budget shortfalls;
- City approval delays;
- Procurement / Tender delays; and
- Design changes.

These issues can be mitigated with proper communication, leveraging the expertise of the consultants and proper project planning. Overall, leading project management tools and practices will be utilized, and the expertise of highly qualified project management leadership and industry experts will be leveraged to take a proactive approach to managing unknown conditions.

Toronto Hydro’s Facilities Asset Management Strategy (filed at Exhibit 2B, Section D6) has established a strong foundation to ensure that these potential planning and execution risks will be mitigated accordingly.

E8.2 Facilities Management and Security

E8.2.1. Summary

Table 1: Program Overview

2020-2024 Cost ($M): 85.1	**2025-2029 Cost ($M):** 145.5
Segments: Facilities Management and Security	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Operational Effectiveness - Safety, Operational Effectiveness - Reliability, Financial Performance, Environment	

Through the Facilities Management and Security Program (the "Program"), Toronto Hydro invests in building improvements that are critical to the operation of the utility's electricity distribution system, demand-driven projects that support the utility's decarbonization objectives, and the ability to modernize its business processes in accordance with the evolving needs and nature of its customers. The facilities owned by Toronto Hydro and covered by the Program include four work centres that have unique footprints and functions, along with 185 stations that serve a critical role in operating the utility's distribution system.

The Program's primary objective is to maintain the infrastructure that supports critical operations of Toronto Hydro's distribution system and replace assets that are end of life and in poor or critical condition. These assets pose an increased risk of failure, which results in an increased risk of business interruption and the deterioration of key outcomes such as safety, reliability, customer service, and productivity. The Program also supports the management and maintenance of Toronto Hydro's buildings in accordance with the growth and evolving needs of the distribution system.

The Program is comprised of the following three areas:

1) **Stations**: Includes investments and improvements to build and maintain the facilities that house Toronto Hydro's distribution stations and manage risks that may arise from any facilities assets deteriorating to the point of poor condition or end of life. As the integrity and operating conditions of stations buildings may significantly affect safety and the reliability of distribution equipment housed within, these assets are critical to grid safety and performance.

2) **Work Centres:** Includes repairs to the facilities that provide a work space for Toronto Hydro personnel and also serve as storage and parking spaces for the utility's equipment, materials, and vehicle fleet. The utility's four work centres are located in the city of Toronto at 14 Carlton Street, 500 Commissioners Street, 71 Rexdale Boulevard and 715 Milner Avenue. The primary function of investments in this area is to minimize safety risks to utility personnel, visitors, and the general public and ensure productivity by replacing poor condition and end of life assets that may otherwise cause hazards or business interruptions. This area also includes investments that support the utility's strategic objectives and outcomes, such as the modernization of business processes in accordance with the evolution of customer expectations and distribution services, and investments to decarbonize in line with Toronto Hydro's Net Zero 2040 Strategy in Exhibit 2B, Section D7.
3) **Security Improvements:** Includes investments in security enhancements at Toronto Hydro's facilities that are necessary to protect the safety and security of employees, assets, and the public. These investments include up-to-date security equipment and technologies. Toronto Hydro also plans to upgrade its preventative security measures to reduce the risk of trespassing, theft, injuries, and cybersecurity attacks.

The Program is a continuation of the activities described in Toronto Hydro's 2020-2024 Rate Application,[1] embodying the utility's Facilities Asset Management Strategy (the "AM Strategy") in Exhibit 2B, Section D5, as well as applicable industry standards, such as ISO 55001. The utility relies on the AM Strategy to manage assets in a cost-effective manner and in order to ensure that facilities remain safe and functional. As discussed in the AM Strategy, the asset condition assessment process determines both a) the risks that may be present in respect of facilities assets and b) plans to mitigate these risks. This assessment and risk management process is a significant part of the planned scope of work for the 2025-2029 rate period. Without sufficient funding to make these investments, Toronto Hydro's facilities would be exposed to the risk of structural failures and significant hazards and/or damage, e.g. due to flooding or leaking. If these risks were to materialize, they would cause severe disruption to the utility's business activities and potentially prolonged outages.

The Program coordinates evaluation and repair work in order to efficiently plan and execute projects. The utility internally coordinates a) its evaluation of a given asset with surrounding asset conditions and its future planned work, and b) capital work on the distribution system, outlined in in the Stations

[1] EB-2018-0165, Toronto Hydro-Electric System Limited Application, Exhibit 2B, Section E8.2.

Renewal (Exhibit 2B, Section E6.6), to align planned facilities projects with distribution projects. For example, if a building requires basement and foundation work, the Program evaluates if other scopes of work can be included at the same time, such as introducing a leak detection system, a sump pump system, or other plumbing refurbishment when the concrete is being removed and trenching can readily take place. Grouping projects together minimizes disruption to stations operations, reduces the potential impacts of the work on customers, and helps the utility manage costs more effectively.

Figure 1 below outlines some examples of stations and work centres. Table 2 outlines some high-level statistics of Toronto Hydro-owned properties.

Figure 1: Examples of Toronto Hydro infrastructure; a downtown substation and work centre.

Table 2: Toronto Hydro Stations Properties Statistics

Category	Quantity
Average Station Property Area	6,200 sq. ft.
Stations Properties above 50,000 sq. ft.	12
Heritage Stations Properties	8
Stations Properties over 40 Years Old	165

E8.2.2. Program Outcomes

Table 3: Outcomes and Measures Summary

Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety objectives by: ○ Ensuring compliance with applicable legislative and regulatory requirements, such as the Occupational Health and Safety Act[2], Ontario Regulation 851: Industrial Establishments[3], the Ontario Building Code[4] and the Fire Code[5]; ○ Providing the utility's employees safe and functioning work centres by repairing deficiencies that may cause hazards; ○ Addressing stations related deficiencies such as the absence of secondary exits, non-compliant stairs, and inaccessible doors along pathways; and ○ Improving internal lighting conditions and repairing external damaged lighting in work areas. ○ Installing enhanced safety systems to deter theft, vandalism and violence towards employees, and reduce the risk of unauthorized access into work centres and stations.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's network reliability objectives and ensures compliance with applicable legislative and regulatory requirements such as the Ontario Energy Board's Cyber Security Framework[6] by: ○ Implementing, maintaining and managing modern commercial security systems and technology in partnership with security subject matter experts; ○ Applying security management policies and procedures across all Toronto Hydro sites; ○ Investing in building-related improvements at stations and work centres that are critical to the operation of Toronto Hydro's distribution system; ○ Mitigating the risk of damage to critical distribution equipment housed within the stations; and

[2] Occupational Health and Safety Act, R.S.O. 1990, Ch O.1.
[3] Occupational Health and Safety Act, R.R.O. 1990, Reg. 851: Industrial Establishments.
[4] Building Code Act, 1992, S.O. 1992, c. 23, O. Reg 332/12.
[5] Fire Protection and Prevention Act, 1997, S.O. 1997, c. 4, O. reg 213/07.
[6] Ontario Cyber Security Framework, 2017.

	○ Prioritizing preventative maintenance of assets that are end of life or in poor condition to mitigate against costly reactive repairs.
Financial Performance	• Contributes to Toronto Hydro's financial objectives as measured by the total cost and efficiency measures by: ○ Using the AM Strategy (filed at Exhibit 2B, Section D6) to optimize assets' capital and operational costs in line with the condition assessment ○ [check workplace consolidation relationship with total efficiency]
Environment	• Contributes to Toronto Hydro's environmental objectives and enables the goals outlined in utility's Net Zero 2040 Strategy (filed in Exhibit 2B, Section D7) by reducing greenhouse gas ("GHG") emissions through: ○ Electrification of building operation systems such as replacing natural gas heaters with air-source heat pumps

E8.2.3. Program Drivers and Need

Table 4: Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Safety and Failure Risk

The Program prioritizes investments that address assets at end of life and in poor condition, in line with the AM Strategy and Toronto Hydro's objectives to operate and maintain a safe and reliable distribution system. The utility evaluates the condition of building assets pursuant to the AM Strategy.[7]

Figure 2 below illustrates the relationship between the probability and impact of failure for the various building systems according to the Uniformat II framework, as discussed in the AM Strategy. The probability and impact measures are an output of periodic building condition assessments. Understanding the relative risk associated with each of the building systems allows Toronto Hydro to efficiently allocate capital funding to the areas that provide the best value and address the greatest risk.

[7] Exhibit 2B, Section D6, at pages 3-4.

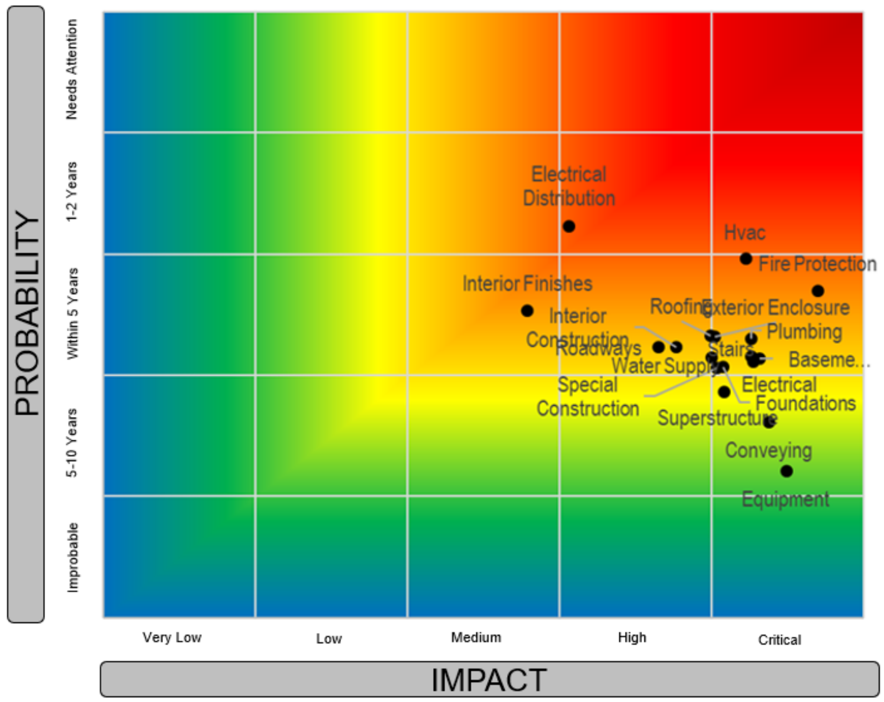


Figure 2: Likelihood-impact matrix for UNIFORMAT II building elements as of 2023

E8.2.3.1 Categories of Facilities Work

Table 5: Types of Program Projects Planned for the 2025-2029 Rate Period

Project Category	Rationale	Risk of Failure
Structural & Envelope (e.g. repairs to the building envelope and façade, windows, foundation and structural elements, beams, joists, columns, etc.)	Addresses safety issues and prevents structural damage of critical supporting functions and deteriorated building performance.	If a structural element were to fail and damage distribution equipment, significant and prolonged outages could occur.

Project Category	Rationale	Risk of Failure
Architectural & Interiors (e.g. roofs, doors, building finishes, office work areas, etc.)	Addresses safety issues and building water-tightness, and promotes optimal building performance.	If a building asset or system failure were to expose interiors to the elements (e.g. water infiltration), distribution equipment could be permanently damaged, costly business interruptions could ensue and hazards may exist to workers and the public.
Fire & Life Safety (e.g. stations fire alarm system upgrades, signage and emergency lighting, etc.)	Replaces obsolete fire alarm systems and addresses safety and compliance issues.	Deficient or lacking fire and life safety systems and assets may endanger employees due to hazards from fire and harmful gases, and also put equipment at risk of damage or destruction, thereby increasing the risk of outage.
Mechanical, Electrical & Plumbing (e.g. HVAC system replacements, supplementing cooling systems, upgrading and replacement of lighting, sump pump replacements, plumbing fixtures, hot water tanks, etc.)	Addresses assets in poor condition, equipment overloading and capacity issues, safety concerns, and achieves compliance with mandated requirements.	Failures of these types of assets and systems may cause damage to equipment (e.g. in the event of flood in basements) or cause operational disruptions and a loss of productivity (e.g. in the event of loss of power).
Civil & Sitework (e.g. exterior access ways and walkways, including pavement, driveways, and parking spaces, etc.)	Addresses safety and security-related concerns.	Deficiencies in assets could cause safety risks (e.g. trip and fall hazards) for employees and the public. Furthermore, deficient or lacking features (e.g. doors that do not properly lock) could result in security risks such as theft, vandalism, or unauthorized access.

1. Structural & Envelope

Structural features are those supporting a building. Envelope features are those that separate a building's interior from its exterior. The integrity and operating condition of a building's structural and envelope features are critical to keeping Toronto Hydro's distribution system reliably operational and ensuring the safety of employees and the public. Structural and building envelope components cannot run-to-fail because one beam or column failure can result in a full building failure, leading to potentially catastrophic safety and reliability risks and significant operational disruptions.

The sections below outline some planned structural and envelope repairs and refurbishments for assets in a deteriorating state. These sections provide the categories of planned work on station assets and the rationale for each type of investment.

a. Structural

Toronto Hydro plans to address issues related to the foundation and supporting structural elements (e.g. beams, joists, and columns) within work centres and stations, including two downtown station structural refurbishments.

Figure 3: Examples of structural deterioration at stations, from left to right: Wiltshire Station exposed and corroded rebar with significant water infiltration, Wiltshire Station exposed rebar in concrete wall.

Figure 4: Examples of structural deterioration at stations, from left to right: Windsor Station cracked concrete floor slab, Windsor Station corroded rebar columns.

Figure 5 provides examples of aging structural assets where deterioration can occur more rapidly and in a greater number of locations when water infiltration is present.

Figure 5: Examples of structural deterioration at work centres, from left to right: 500 Commissioners Building C – spalling concrete wall with preventative netting; 500 Commissioners Building C – exposed deteriorated waterproofing; 500 Commissioners Building C – rusted steel staircase.

b. Envelope

Toronto Hydro plans to address issues related to end of life building envelope elements such as exterior cladding, windows, and roofing systems to protect critical equipment from weather. The utility's envelope investments in stations' window upgrades and increased façade insulation will advance the utility's objective to reduce its facilities' GHG emissions by increasing energy efficiency

Figure 6: Examples of envelope deterioration at stations, from left to right: Glengrove Station concrete block wall cracking, Duncan Station brick wall cracking, Junction Station brick wall cracking.

Figure 7: Examples of envelope deterioration at work centres, from left to right: 500 Commissioners Building A – cracking of precast panels at the Control Centre; 14 Carlton – deteriorated windows, sealant, and frame.

2. Architectural & Interiors

The architectural system and interiors of a building comprise a building's core systems, including the roof, doors, floor plans and wall partitions, and interior finishes and furnishings.

a. <u>Architectural</u>

Toronto Hydro must proactively and preventatively invest in architectural repairs to maintain the integrity of its stations portfolio. When structural damage is unearthed once damaged waterproofing is removed from a station, the utility typically pairs architectural repairs to waterproofing systems with structural repairs of the underlying building assembly and structure. Other architectural items that require repair or maintenance to ensure worker safety are fire rated enclosures, egress systems, and exits.

Figure 8: Examples of architectural deterioration at stations, from left to right: George and Duke Station deteriorated concrete stairs, Centre Drive Station water infiltration from roof.

Figure 9: Example of Terauley Station, replacing non-code-compliant stairs and railings with functional ones, and improved dock access.

b. <u>Finishes</u>

Within the utility's stations portfolio, Toronto Hydro plans to address issues related to buildings' interior finishes that directly impact user safety. As examples, certain lighting standards are required to keep buildings at an acceptable level of brightness. Furthermore, deteriorated flooring and stair treads can cause tripping hazards. Maintaining, repairing, and replacing these finishes provides a safe and accessible workplace for the employees who interact with the utility's stations.

Within the utility's work centres, Toronto Hydro plans to address issues related to the building interior finishes (e.g. coatings, carpets, workstations and office furniture) where existing materials are end of life or in poor condition and where assets no longer meet the needs of the utility's workforce. As examples, improving the working condition of some finishes will promote employee safety, such as lighting standards to keep buildings at an acceptable level of visibility, and mending deteriorated carpet and flooring will help reduce the risk of tripping hazards. Furthermore, maintaining finishes at a reasonable standard prevents the need for significant renovations to address cumulative deterioration.

3. Fire & Life Safety

Fire and life safety systems, including fire suppression, alarms, and preventative equipment, protect workers in the event of fire or environmental hazards and are essential to building, staff, and public safety.

Stations without functioning life safety or fire alarm systems are a high priority investment. The Program will continue work that the utility commenced in the 2020-2024 rate period work to replace outdated fire alarm panels. As of 2023, Toronto Hydro upgraded five (5) panels to a current and compliant fire panel system during the current rate period.

It is safer and less expensive to proactively repair and replace fire and life safety systems. If a fire alarm device is in a state of disrepair, the utility must hire fire watch personnel for patrol until the fire alarm system is back online. The cost of hiring a 24/7 fire watch for a device is prohibitive if the fire watch must be in place for days or weeks until a part is shipped for the alarm repair or replacement. This type of reactive response incurs significantly higher costs than a proactive repair and replacement program.

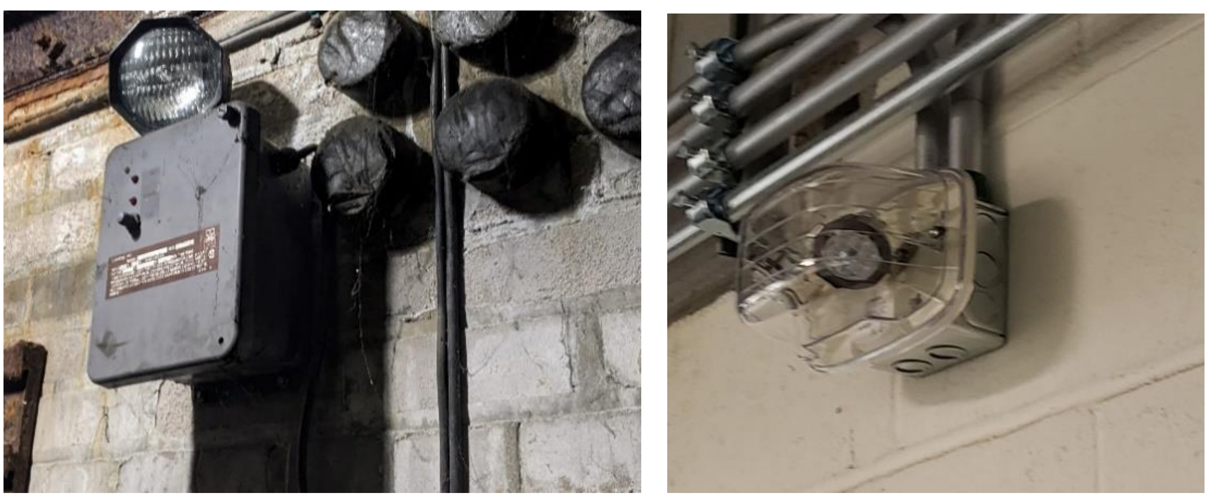


Figure 10: Example of Terauley Station, replacing non-compliant emergency lighting (left) with functional and compliant lights (right).

Within work centres, the 500 Commissioners work centre has aging dry sprinkler systems and faulty water systems that require maintenance and repair. A side benefit of modernizing and improving the condition of these systems would be to reduce nuisance alarms that disrupt work at work centres.

[redacted]. Reducing the incidence of false alarms triggered by faulty systems would alleviate this risk. Furthermore, by implementing modern systems like two-stage alarms, fire alarms and evacuations can target localized building zones and minimize the disruption to critical control operations.

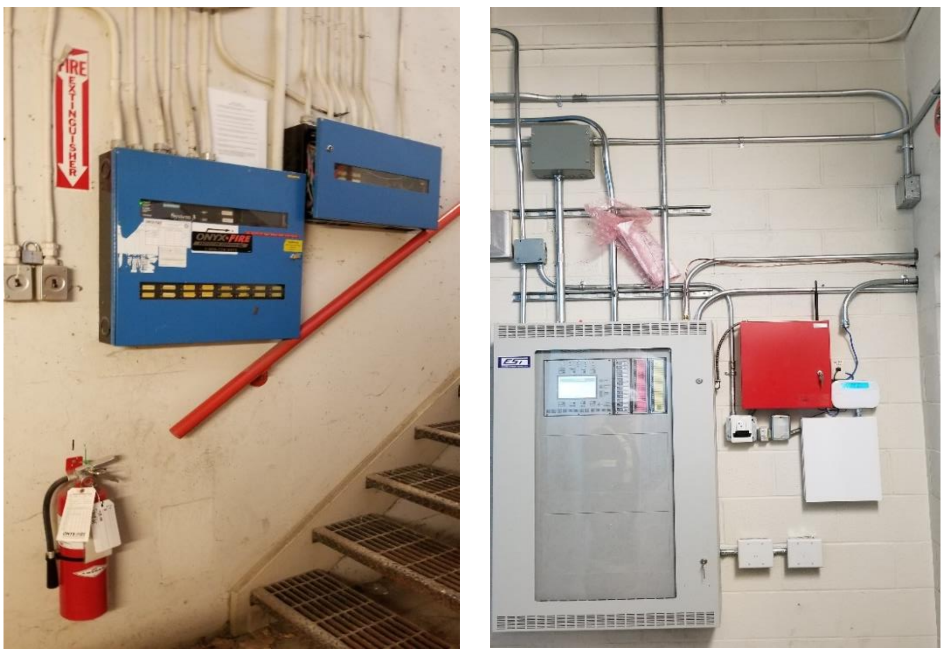


Figure 11: Example of Esplanade Station outdated fire alarm panel (left) with a new, functional panel (right).

4. Mechanical, Electrical & Plumbing

Mechanical and electrical assets include plumbing, heating, ventilation and air conditioning ("HVAC") systems, site lighting, electrical panels, electrical wiring, building automation systems, and power distribution systems in Toronto Hydro's buildings.

These systems are critical to reliable operation of the utility's work centres and stations buildings. Toronto Hydro plans to replace end of life infrastructure and equipment, including cooling systems for critical equipment in stations, to improve reliability on high temperature days and prevent disruptions or outages due to overheating equipment. The utility also plans to make investments in plumbing and emergency sump systems and other infrastructure to reduce the risk of asset failures and damage to equipment, which may disrupt grid operations.

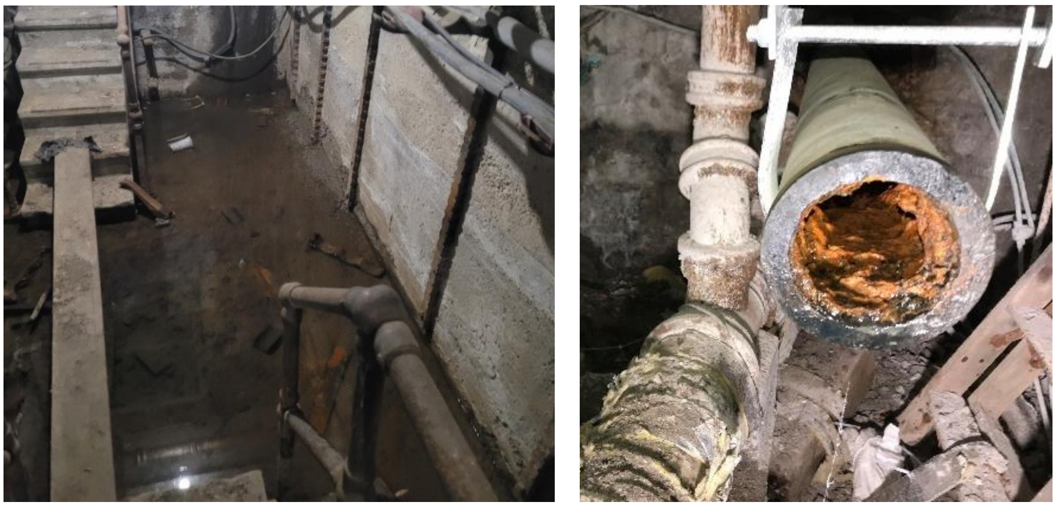


Figure 12: Examples of mechanical and plumbing deterioration at Stations: Terauley Station with a flooded basement and Terauley Station water service line clogged and full of debris.

Figure 13: Examples of HVAC additions at Stations: Strachan Station without additional air conditioning (left) and after with two new condensing units installed for keeping air temperature and equipment cool (right).

Figure 14: Examples of HVAC additions at Stations: Cavanagh Station without additional air conditioning (left) and after with ducts and venting installed for keeping air temperature and equipment cool (right).

5. Civil & Sitework

Property civil work and sitework includes work related to exterior access ways and walkways, pavement, driveways, parking spaces, and exterior lighting. A variety of investment and maintenance needs are present in this area. Certain exterior surfaces at work centres and stations are in poor condition and need repair to prevent tripping hazards, pot holes, delamination, and water ponding. Exterior lighting at certain stations is currently inadequate for response crews' ability to work safely. Additional paving is required to accept multiple trucks on site at several stations as a need for operational efficiency.

Figure 15: Examples of driveway deficiencies at Stations: Hunting Ridge Station driveway in disrepair, Longfield Station with no available parking for response crews.

E8.2.3.2 Stations

Toronto Hydro's investments over the 2025-2029 rate period will focus on stations. Approximately 50 percent of the planned work will address stations assets and infrastructure. Figure 14 below highlights some examples of stations with poor quality structural assets. Deterioration at this level indicates that the structural system has operationally lost its serviceability for the actual service load that the structure is subjected to and presents a high risk to occupant and equipment safety. To mitigate the risk of partial or complete building collapse that may ensue from these conditions and prevent significant damage to distribution equipment or catastrophic safety risks to employees and the public, the utility must address these deficiencies in a timely and effective manner.

Figure 16: Examples of existing stations in critical condition, from left to right: George and Duke Station, beam with exposed rebar, Defoe Station cracked beam, Junction Station deteriorated foundation wall.

Toronto Hydro's portfolio includes large-footprint stations, stations on heritage sites, and stations integrated into residential neighborhoods. To address stations-related issues, the utility must tailor specialized design and investment plans to each station's features and condition. These investment plans consider asset age, site condition, priority, probability of failure, and impact to yield a system criticality rating.

E8.2.3.3 Work Centres

1. Overview

In addition to investments to maintain, repair, and replace assets as discussed above under subsection E8.2.3.1, Toronto Hydro plans to invest in work centres in accordance with its strategic outcomes and objectives. Work centres house Toronto Hydro employees and provide a physical space to operate the business. Employees have functional workplaces that enable them to provide quality service to customers. As the nature and needs of customers evolve and the utility invests in growing its distribution system and modernizing its business processes in response, it also must have adequately furnished work centres for employees to execute work and provide customer service. Approximately 35 percent of the planned work in the Program is related to work centres.

The volume of asset management work required at work centres over the 2025-2029 rate period is lower compared to the Stations segment, with three of the four work centres being relatively new (having been built or retrofitted within the last few decades) and in good operating condition.

Key work centre-specific initiatives include:

- **Work Centre Decarbonization:** targeted projects that will decrease GHG emissions from Toronto Hydro's work centres; and
- **Work Centre Modernization:** select improvements to office workspaces that support the future of collaborative and flexible work, and efficiently use office areas.

2. Work Centre Decarbonization

The Program includes investments to decarbonize work centres in alignment with the utility's Net Zero 2040 Strategy.[8] Toronto Hydro's Customer Engagement showed that a majority of the utility's

[8] Exhibit 2B, Section D7.

customers indicate general support for investments that reduce Toronto Hydro's environmental impact.[9]

Toronto Hydro will phase the timeline for decarbonization investments, starting in the 2020-2024 rate period and continuing through the 2025-2029 rate period and beyond, until Net Zero targets are achieved by 2040. The utility will execute these investments in a balanced manner to achieve decarbonization objectives while maintaining costs at a reasonable level and minimizing the risk of stranded assets and business interruptions.

Toronto Hydro's decarbonization investments in the 2025-2029 rate period will focus on assets that are at end of life to avoid stranding assets. The utility will engage in fuel switching by replacing selected fossil fuel-powered assets identified with electric assets to prudently deliver a high level of decarbonization proportionate to project costs. The utility will concurrently make investments in building efficiency, building automation systems ("BAS"), and other building envelope measures to improve the energy efficiency of its work centres, which will reduce overall energy use and require fewer electrified assets for heating and cooling work centres.

The three main investment streams targeting GHG emissions at work centres will consist of:

1. **Fuel Switching (Eliminate Scope 1 Emissions)**: replacing natural gas- or other fossil fuel-powered equipment with electric assets.[10]
    a. GHG emissions from natural gas heating accounted for majority of all of the utility's GHG building emissions in 2022.
    b. Toronto Hydro will target aging and/or poor condition natural gas equipment minimize stranded assets.
2. **Improve Building Efficiency (Reduce Scope 2 Emissions)**: improving energy performance to reduce buildings' electrical loads.
    a. In conjunction with eliminating GHG emissions from fossil fuel-powered equipment, Toronto Hydro will reduce the electrical load of its buildings through efficiency measures, which would further reduce GHG emissions associated with line losses

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[9] Exhibit 1B, Tab 5, Schedule 1

[10] Scope 1 emissions are direct GHG emissions that occur from sources controlled or owned by an organization. Scope 2 emissions are emissions that an organization causes indirectly and that come from where the energy it purchases and uses is generated. Scope 3 emissions are emissions that are produced by an organization's value chain, and not as the result of an organization's assets or activities. This program does not address measures to reduce the organization's Scope 3 emissions.

from the utility's consumption of electricity delivered through transmission and distribution grids.

b. Building Automation Systems ("BAS"): BAS provide a centralized control system for a building's facilities systems, including electrical and mechanical (heating, ventilating, air conditioning) systems, which provides both visibility and control of the building's operations and performance, ensuring harmonious and efficient operations according to occupant requirements. Part of the investments will add legacy and new equipment to the BAS network.

c. Envelope Improvements: identifying areas with air leakage and implementing appropriate repairs reduces unnecessary heating and cooling, and lowers the demand on building operation. Intensive envelope improvements include façade retrofits and roof repairs. Although these retrofits and repairs are standard maintenance for aging buildings, Toronto Hydro's investments will enable increased insulation above minimum code requirements to retain heating and cooling more effectively, lowering energy consumption.

3. **Additional Improvements (Reduce Scope 1 & 2 Emissions):** other improvements to building operation efficiency.
   a. Adding two cooling setpoints to air conditioning units that allow high operation on hot days and low operation on more frequent mild days.
   b. Providing additional CO_2 sensors to act as occupancy monitoring, to automatically adjust ventilation for a space according to real-time occupancy.
   c. Air curtains at warehouse overhead doors to reduce outdoor air infiltration at warehouse and garage spaces when the overhead doors are open.

3. Work Centre Asset Management

As discussed in the AM Strategy, Toronto Hydro applies a tailored investment approach to its head office located at 14 Carlton, in accordance with the age and deteriorated condition of the building.[11] The utility must reactively repair and maintain assets to reduce the risk of infrastructure failure, while navigating rising costs and operational challenges due to the building's age, limitations from the original design, heritage status, location, and operational significance (such as the housing of one of the utility's two enterprise data centres). One example that highlights the challenge of maintaining

[11] Exhibit 2B, Section D6, subsection D6.3.

the 14 Carlton work centre is ongoing façade repairs. The last major building masonry repair project was executed in 2016. Toronto Hydro plans to undertake the next repair project in the 2025-2029 rate period, as the risk of leaving the façade in disrepair could result in material falling from the building, causing hazards to employee or public safety. Since masonry repairs tend to be disruptive of building operations, involving significant vibrations, dust, loud noise, and scaffolding structures, the utility will plan these repairs in a manner that will minimize the risk to the 14 Carlton enterprise data centre, to avoid materially reducing data centre redundancy through planned outages and impacts during construction.

4. Work Centre Modernization

Toronto Hydro will selectively invest in its office workspaces to support an engaging environment that promotes productive and collaborative hybrid work, and to efficiently optimize office footprints. Investments in physical office spaces such as workstations, meeting rooms, leader offices, and shared spaces will enable employees to more efficiently engage in collaborative and inter-departmental group work. As Toronto Hydro's workforce grows and evolves, the utility will also leverage these investments to improve the efficiency of office spaces by consolidating workstations with a large footprint and providing space for new employees without requiring expansions.[12] Since the relevant assets typically consist of furniture and technology with relatively short lifecycles that are typically capitalized within ten years, the utility can plan investments in a flexible manner.

Investments to modernize work centres will support the growth of the utility's workforce and promote employee satisfaction, retention, and adaptation to flexible work practices, enabling personnel to efficiently and effectively perform business operations and serve customers.

c. Workstations

Toronto Hydro will install new workstations to replace bulky, space-inefficient, and aging or deteriorating workstations and increase employee density. These investments will reduce the cost of expanding the utility's workforce by providing a smaller physical footprint per employee.

d. Meeting and Training Rooms

Toronto Hydro will install audio and visual upgrades, including speakers, microphones, monitors, and TVs, in meeting and training rooms to support online web conferencing. The utility will also invest in

[12] See Exhibit 4, Tab 4, Schedule 4 for more information on Toronto Hydro's workforce over the 2025-2029 rate period.

modern furniture and design features to replace damaged and outdated furniture. These investments will support employee productivity and efficiency within the hybrid work environment.

e. Common Spaces

Toronto Hydro will make investments to update common spaces in its work centres to support hybrid office work by facilitating face-to-face communications. The purpose of these investments is to transform simplistic waiting areas and empty spaces in the utility's work centres into places for employees to work, gather around, charge devices, break up their day with a change of scenery, meet visitors or guests, share content, or take a phone call. Providing access to spaces for collaborative and in-person interactions to take place will contribute to employee satisfaction, and thereby productivity and retention.

E8.2.3.4 Security Improvements

Toronto Hydro will make investments to improve the utility's physical security infrastructure and support operations. Approximately 15 percent of the planned work under the Program is associated with security improvements. As the utility's properties are located in a broad range of neighbourhoods across the city of Toronto, stations and work centres are at risk of general theft, vandalism, and trespassing. Other threats include attempts by customers or members of the public to harass staff or threats to distribution operations and the distribution system by malicious organized actors, such as terrorism or cyber security breaches. Security measures that protect properties from physical threats also contribute to the safety of employees and critical equipment and assets, and to the overall reliability of the distribution system. The integrity of the utility's physical security systems is essential to ensure the distribution system's safe and reliable operation. Toronto Hydro will plan and make investments in a manner that is strategic, proactive, and responsive to identified risks as well as in alignment with the Ontario Energy Board's Cyber Security Framework.[13]

Electricity distributors are targets for security breaches because they play a critical role in providing an essential service and host a broad database of customer information, Similar to other public service providers and infrastructure operators such as hospitals, public transit operators, traffic management systems, emergency services, and financial hubs. The utility's planned security

[13] Ontario Energy Board, Ontario Cyber Security Framework (December 6, 2017) https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf

improvements will address existing gaps in the physical safety systems and implement proactive measures to lower the risk of safety breaches.

Toronto Hydro will focus on improving security measures in two categories: physical access measures and technology and network measures. Within the physical access category, the utility will implement physical changes to site security to improve control over access to properties. Within the technology and network measures category, the utility will improve video monitoring to provide improved response abilities by its Physical Security Operating Centre ("PSOC") to address breaches of security.

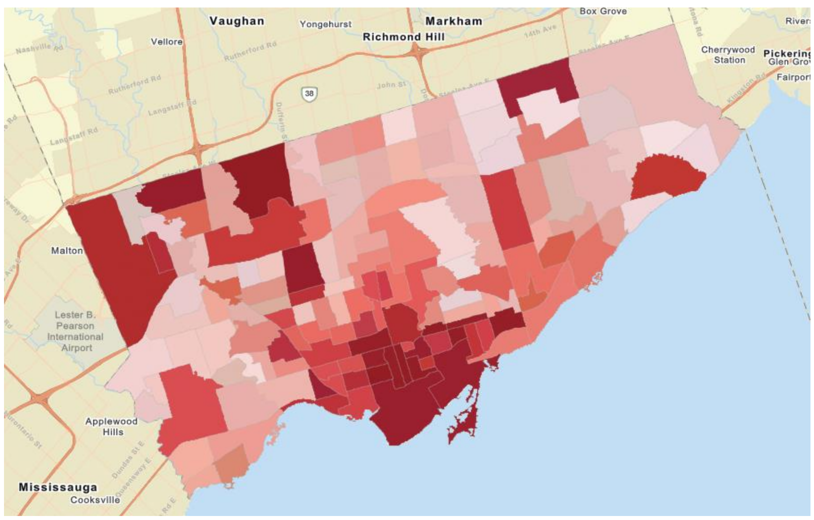

Figure 17: Major crime indicators; Toronto Police Service 2014-2021 statistics for breaking and entering and robbery.[14]

5. Network Security Improvements

The information technology and operating technology ("IT/OT") assets that enable Toronto Hydro to effectively and efficiently manage its distribution system, such as Supervisor Control and Data Acquisition ("SCADA"), also attracts heightened physical and cyber security risks. The utility must protect its IT/OT infrastructure and increase resilience against these diverse risks to ensure that critical grid distribution equipment and customer service functions remain reliably operational.

[14] Toronto Police Service Public Safety Data Portal https://data.torontopolice.on.ca/pages/major-crime-indicators

Within network security improvements, [redacted]

[redacted]

[redacted]

6. Physical Security Improvements

Toronto Hydro will invest in physical security measures to prevent unauthorized access to stations while also keeping them accessible for authorized personnel. Examples include providing increased outdoor lighting, repairing fencing, having adequate fence heights, and installing additional barriers such as barbed wire where required. Other improvements relate to door and gate openings. The utility will make investments to ensure that card readers work reliably when staff need to access a location [redacted]

Figure 18: Examples of University Station entrance door in poor condition (left) and after being retrofitted via the station door program (right).

E8.2.4. Expenditure Plan

Toronto Hydro plans to spend approximately $145.5 million over the 2025-2029 rate period to respond to the previously discussed needs and to make the proposed investments. The historical and forecast costs for the Program are set out in Table 6 below. The utility will determine the full scope of work to be performed under the work centres and stations categories based on risk-based prioritization in line with the AM Strategy and workload balancing over the 2025-2029 rate period.

Approximately 50 percent of Program expenditures will be dedicated to stations work. As discussed in detail above, 87 percent of Toronto Hydro's stations are over 40 years old and require significant upgrades to architectural, fire and life safety, mechanical and electrical, and civil and plumbing infrastructure and to ensure building and fire codes compliance. These investments will also enable the utility's security measures to better align with the principles of the Ontario Energy Board Cyber Security Framework.

35 percent of Program expenditures will account for work centre-related projects to address aging and deteriorating assets and office space modernization initiatives that will increase the productivity

of Toronto Hydro's workforce. This work will also facilitate investments in decarbonization at the utility's work centres to reduce facilities-related GHG emissions in accordance with the Net Zero 2040 Strategy.[15]

The remaining 15 percent of the Program expenditures will focus on implementing security improvements at stations and work centres.

In accordance with the AM Strategy, the Program will prioritize the proactive replacement of critical assets that are end of life and in poor condition for the 2025-2029 rate period. This approach will reduce the risk of emergency work, which can impact the safe and reliable distribution of electricity, and optimize the value the utility receives from assets in service.

Table 6: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Stations	1.7	4	11.8	11.3	10.3	15.1	15.1	14.5	14.5	13.3
Work Centres	5.5	6.2	6.9	8.0	5.5	10.2	10.4	10.5	10.6	10.6
Security Improvements	3.4	5.4	2.7	1.5	1.0	4.3	4.3	4.1	4.2	3.8
Total	**10.6**	**15.6**	**21.4**	**20.8**	**16.8**	**29.6**	**29.8**	**29.1**	**29.3**	**27.7**

Toronto Hydro will prioritize planned work according to the impact of a given asset's failure on the utility. As described in the AM Strategy, the Program first prioritizes assets whose failure poses a safety risk to Toronto Hydro personnel or the general public. The program next prioritizes assets whose failure impacts business continuity and the protection of the distribution system. Finally, the program prioritizes assets whose failure would impact productivity gains and the achievement of other business objectives third.

E8.2.4.1 Stations

Toronto Hydro assesses stations building assets and assigns a condition rating of critical, poor, fair, good or excellent on a regular basis in line with the AM Strategy. Assets that received a poor condition rating will be addressed within the 2025-2029 plan period. Assets in fair condition will be closely monitored and maintained under a preventative maintenance program. Assets will be also

[15] *Supra* note 8

be evaluated to ensure that a net reduction in GHG emissions to support net zero targets will be prioritized upon repair or replacement.

Finally, repairs for assets in good condition are not planned for the 2025-2029 period. Toronto Hydro will only replace assets that are end of life and are in poor condition. Work on these identified assets will proceed in line with the prioritization identified in the AM Strategy and described above.

Refer to Table 7 below for the planned capital expenditure work for Stations.

Table 7: Stations Capital Projects Work

Project Category	Major Assets to be Replaced	Percentage of Estimated Segment Costs
Structural & Envelope	Foundation, beams, joists, columns	20%
Architectural & Interiors	Roofs, doors, window	15%
Fire & Life Safety	Fire alarm systems, emergency lighting, signage	25%
Mechanical, Electrical & Plumbing	Interior systems, power distribution, lighting, HVAC, sump pumps, plumbing fixtures, hot water tanks, drainage pipes, tanks, fittings, sanitation	30%
Civil & Sitework	Pavement, driveways, parking areas, walkaways	10%

E8.2.4.2 Work Centres

As mentioned in section E8.2.4.1 Stations, the AM Strategy and priority ratings are also used to classify work centre assets. Toronto Hydro will only replace assets that are end of life and in poor condition. This means deferring the replacement of assets that are end of life but are in fair or good condition or are “run-to-fail”.

Refer to Table able 8 below for the planned capital expenditure work for Work Centres.

Table 8: Work Centre Capital Project Planned Work

Project Category	Major Assets to be Replaced	Percentage of Estimated Segment Costs
Structural & Envelope	Foundation, beams, joists, columns	20%
Architectural & Interiors	Roofs, doors, window	20%
Fire & Life Safety	Fire alarm systems, emergency lighting, signage	20%
Mechanical, Electrical & Plumbing	Interior systems, power distribution, lighting, HVAC, sump pumps, plumbing fixtures, hot water tanks, drainage pipes, tanks, fittings, sanitation	20%
Civil & Sitework	Pavement, driveways, parking areas, walkaways	15%
Office Workspace Transformation/ Modernization	Collaborative furniture, open spaces, hybrid work areas, audio visual enhancements	5%

E8.2.4.3 Security Improvements

The planned projects for the 2025-2029 rate period under the Security Improvements segment will support and expand integrated security features (e.g. video systems, keys, intercoms, access control measures, and duress stations). These security investments will both replace existing aging and deteriorated and also expand new assets to address any identified security gaps or risks [redacted]

Security improvements can be broken down into two areas: network security improvements and physical security improvements. Table 9 below shows a breakdown of the capital expenditures in each of these areas.

Table 9: Security Capital Projects Work

Project Category	Major Investments and Assets to be Replaced	Percentage of Estimated Segment Costs
Network Security Improvements	[redacted]	50%
Physical Security Improvements	Exterior lighting, fencing, card readers, automatic gates, exterior doors, exterior windows, and modernization.	50%

E8.2.5. Options Analysis / Business Case Evaluation ("BCE")

E8.2.5.1 Option 1: Run-to-Fail Approach

Under the run-to-fail approach, Toronto Hydro would delay necessary investments in work centres and stations and would perform replacements and repairs only on a reactive basis, when an asset fails. Since the majority of assets that are end of life and in poor condition are critical to the utility's operation, this approach would pose a significant risk to the business continuity of Toronto Hydro's operations. This approach would also run counter to the Ontario Energy Board's Cyber Security Framework, which stresses the importance of physical security to support utilities' cyber security objectives. This option would incur costs to reactively repair and replace assets, and significantly increase costs associated with reactive work, rentals, and labour to accommodate long lead times for specialty equipment.

Some of the effects of instituting a run-to-fail strategy would include:

- **Stations:** Maintenance and repairs to fire alarm panels, large HVAC units, and heritage station assets must be planned in advance to account for engineered design, analysis, material purchases with long lead times and/or custom-built materials (e.g. in support of heritage preservation). Applying a run-to-fail strategy to these types of assets would lead to business disruptions when the assets fail. Asset failure could also directly affect grid reliability if failing assets were to damage distribution equipment or expose them to damage and faster deterioration. The cost associated with unexpected failures and reactive repairs often outweighs the cost of proactive repairs due to the fact that reactive repairs generally require additional scope and rapid response involving labour overtime. This approach would also increase the risk of safety hazards by deferring work to bring the utility's stations into compliance with the Ontario Building Code by addressing existing water infiltration, building integrity and exterior lighting issues.

- **Security:** Deferring investments in security improvements will [redacted]
- **Work Centres**: Deferring efforts to decarbonize facilities assets at the utility's work centres would cause the utility's emissions to remain at current levels, compromising the utility's Net Zero by 2040 objective and leaving more decarbonization work for future rate periods.

E8.2.5.2 Option 2 (Selected Option): Maintenance and Replacement of End of Life and Poor Condition Assets and Investment in Security Improvements at Certain Toronto Hydro Facilities

Under this approach, Toronto Hydro would focus on asset lifecycles and condition assessments to selectively determine assets that require maintenance and replacement. Ongoing preventive maintenance reduces the risk of unexpected asset failures that could disrupt the utility's operations. Furthermore, this option allows the utility to optimize its capital expenditures by replacing assets in poor condition and retaining assets that are at end of life but in good condition.

Some of the effects of implementing this option would include:

- **Stations:** Assets that are end of life, but are either in good or fair condition or are run-to-fail by nature will remain in service, allowing the utility to focus expenditures and efforts on stations assets that require more immediate attention. By addressing hazards and asset deficiencies (e.g. those relating to lighting, HVAC, flooring, and stairs), Toronto Hydro can achieve and maintain compliance with legislative and regulatory requirements and minimize the safety hazards posed by current issues. This approach also allows the utility to use a competitive bids process to obtain more favourable acquisition costs for goods and services while maintaining the quality of work and process integrity.
- **Security:** By taking a proactive approach to improving security systems, Toronto Hydro can minimize physical threats to its assets by enabling a real-time response to threats. [redacted]

[redacted]

- **Work Centres:** Decarbonization, electrification, and energy efficiency investments under this option would enable Toronto Hydro to meet its emissions reduction outcomes over the 2025-2029 rate period and enable healthy progress to the utility's target to reach Net Zero by 2040, while pacing investments to contain costs for optimum benefits and avoid stranded assets.[16]

E8.2.5.3 Option 3: Preventative Maintenance and Replacements of All End of Life Assets and Investing in Security Improvements at All Toronto Hydro Facilities

Under this option, Toronto Hydro would replace all assets that are end of life, irrespective of specific asset condition, and would implement security improvements (such as upgrading video management system hardware and software) at a greater number of stations. This approach would also include preventative maintenance on all assets, without regard for asset condition, function, or criticality. This approach would require significantly higher capital expenditures, and would increase the risk of stranding assets.

In addition to the points listed under Option 2, the benefits of this option would include:

- **Stations**: Toronto Hydro would replace all assets at end of life, which would improve their reliability and provide operational savings by reducing the financial burden of reactive maintenance. These benefits would be offset by a significant increase in proactive capital investments under this option.
- **Security:** Security enhancements would be completed [redacted]
- **Work Centres:** This option would enable advanced lighting systems across all sites, HVAC retrofits, and renovations for refined BAS and building operation and offer greater employee work optimization. Under this option, Toronto Hydro would also significantly accelerate

[16] Exhibit 1B, Tab 2, Schedule 1

decarbonization, electrification, and energy efficiency investments, which would reduce GHG emissions faster and set the stage for the utility to reach Net Zero earlier than 2040.

E8.2.5.4 Evaluation of Options

Toronto Hydro has selected Option 2 as the Program's preferred approach for the 2025-2029 rate period since it ensures the optimal outcomes in terms of employee and public safety, grid reliability, cyber security, and GHG emissions while optimizing overall asset lifecycle costs and prudently pacing capital investments. In addition, the proactive approach to asset management in accordance with the AM Strategy under Option 2 would yield several productivity and efficiency benefits. This option provides the best safety, reliability, security and GHG emissions outcomes for ratepayers while controlling costs more effectively than Option 3.

Option 1 offers lower planned maintenance costs but potentially higher reactive maintenance costs. The implementation of this option would compromise the utility's grid reliability and would create the risk of business disruption. It would further compromise public and employee safety, and would lead to a less efficient allocation of capital expenditures, as the utility incurs cost and time benefits from the proactive procurement and replacement of facilities assets.

Option 3 offers additional asset reliability and would decrease the utility's operational costs but does not optimize the utility's asset management process and would represent a significant cost escalation for ratepayers.

E8.2.6. Execution Risks & Mitigation

The Program is vulnerable to several risks that could affect the planning and timing of proposed investments, including:

- Delays in obtaining the necessary approvals and permits may delay the start or completion of projects. To mitigate against this risk, Toronto Hydro will utilize subject matter experts to work with the necessary stakeholders in order to obtain approvals and permits in a timely manner. In addition, the utility will initiate the relevant processes as early as possible to ensure permits are issued for the project's scheduled execution timing and mitigate delays.
- The rising costs of material and labour are an ongoing issue in the post-COVID market. Supply chain disruptions have become an ongoing issue across many industries as well, and have continued to pose a risk throughout 2023.

- Legacy environmental conditions (e.g. asbestos or PCBs) might require further testing and analysis, which may affect project budget and execution schedule. To mitigate against this risk, Toronto Hydro will seek subject matter expertise for a thorough review of actual field conditions in high-risk locations prior to developing a project plan and incorporate these findings during the procurement process to limit the cost escalation of abatement work.

E8.3 Fleet and Equipment Services

E8.3.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 36.7	**2025-2029 Cost ($M): 43.7**
Segments: Fleet and Equipment Services	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Operational Efficiency - Reliability, Environment, Operational Efficiency - Safety, Financial Performance	

The Fleet and Equipment Services program (the "Program") governs the procurement, maintenance, and disposal of vehicles and equipment that are required to support Toronto Hydro's functional and operational needs. The Program's primary objectives are to optimize the utility's vehicle and equipment asset lifecycle costs, and to ensure that fleet assets perform reliably and maintain employee and public safety. Capital investments within the Program are grouped into two categories: (1) vehicles: which includes, (a) heavy duty vehicles, used primarily to perform distribution work and transport operators and equipment; and (b) light duty vehicles, which are fully equipped for employees to inform, manage, and monitor distribution work; and (2) equipment for employees and vehicles (e.g. forklifts, trailers, telematics systems, boom lifts, protective gear, etc.). The Program and its constituent segments are a continuation of the activities described in the Fleet and Equipment Services program in Toronto Hydro's 2020-2024 Rate Application.[1]

Toronto Hydro's capital investments in its vehicle fleet yield the following benefits:

- Optimization of vehicle operating costs;
- Minimization of fleet downtime due to repairs and a corresponding increase in fleet reliability;
- Increase in vehicle efficiency, i.e. lower fuel consumption and idling reduction;
- Improvements in shop efficiency through replacing older and poor condition vehicles that are more labour-intensive for maintenance purposes with new vehicles;
- Reduction in environmental impacts such as reductions in greenhouse gases emissions the amount of maintenance fluids used; and

[1] EB-2018-0165, Toronto Hydro-Electric System Limited Application, Exhibit 2B, Schedule 8.3.

- Increased employee, field crew, and public safety, as newer vehicles are equipped with new safety technology (such as back-up cameras, lane departure warning, emergency braking warning, driver safety alerts, etc.).

E8.3.1.1 Toronto Hydro's Fleet Asset Management Strategy

Toronto Hydro optimizes the level and pace of capital investments to minimize the utility's maintenance and repair costs while maintaining safety and reliability. Toronto Hydro applies its fleet asset management strategy (the "Strategy") to achieve these outcomes. The Strategy takes a two-step approach as follows.

At the first step, it uses a Life Cycle Analysis ("LCA") approach to identify groups of assets whose characteristics (e.g. vehicle type, age, mileage, anticipated corrosion) enable the utility to estimate potential increases in their operating costs. As vehicles age, ownership costs such as purchase costs decrease and operating costs such as fuel, maintenance costs, and downtime increase. The utility uses its LCA to anticipate vehicle needs and fleet turnover for short term (0-2 years) and long term (2-7 years) expenditure planning purposes.

In the second step, the Strategy then assesses the actual condition of assets under consideration using an asset condition assessment to decide whether to replace or dispose of a given vehicle. This is an 85-point vehicle condition inspection metric to annually evaluate all asset components and determine whether parts and systems are working effectively. Because a replacement cycle varies depending on the vehicle make, model year, equipment design, and operating environment, some vehicles that are in poor condition may require replacement before the LCA criteria is met and some vehicles that meet LCA criteria may be in good condition and not warrant replacement. Replacement cycles are additionally impacted by organizational objectives, such as the decarbonization and electrification of fleet assets, whereby the utility may replace decommissioned internal combustion engine vehicles with electric or hybrid vehicles.

The Strategy enables Toronto Hydro to replace vehicles at the lowest total lifecycle cost, which occurs at the point in time immediately before operating costs exceed ownership costs. It also promotes utility performance through the maintenance of a reliable fleet for completing distribution work in a timely and safe manner, and enables the utility to prudently plan and pace its fleet investments. Finally, the Strategy enables Toronto Hydro to meet its organizational objectives, such as the decarbonization of the utility's fleet assets.

To assist with modelling its LCA, Toronto Hydro has successfully operated in line with recommendations from a third-party consultant on the optimal replacement of fleet vehicles. The utility will continue to apply its current methodology over the 2025-2029 rate period. Over the 2020-2024 period, Toronto Hydro's application of the LCA has benefited the utility by enabling it to forecast future fleet needs with a high degree of accuracy, and plan and pace its investments appropriately to maintain fleet safety and reliability.

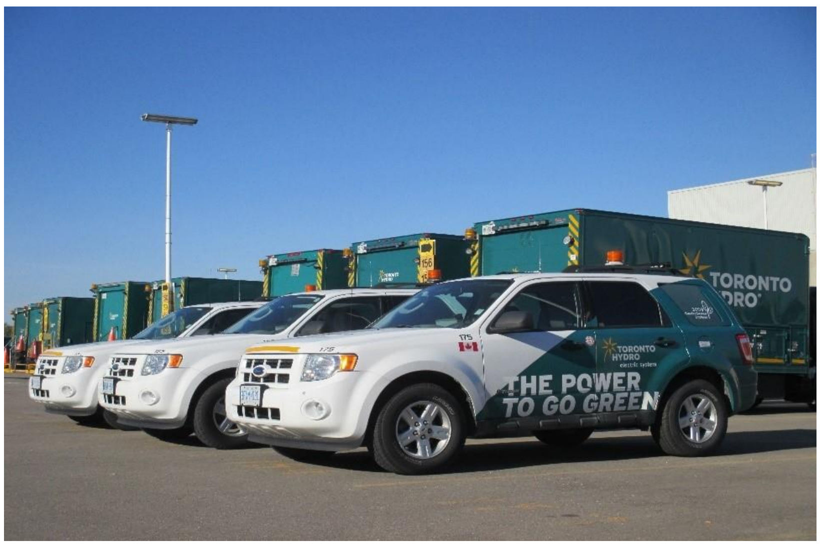

Figure 1: Toronto Hydro Fleet

E8.3.1.2 Decarbonizing Toronto Hydro's Fleet

Over the 2025-2029 plan period, Toronto Hydro will plan its vehicle and equipment investments in alignment with its objective to achieve net zero scope 1 greenhouse gas ("GHG") emissions by 2040, as outlined in the Net Zero 2040 Strategy document in Exhibit 2B, Section D7. Decarbonizing Toronto Hydro's fleet portfolio is critical to achieving this goal.

Aiming to reduce Toronto Hydro's GHG emissions, the utility will reconfigure its fleet composition to gradually increase its complement of electric and hybrid operation vehicles. Within a given vehicle class, electric vehicles ("EVs") and hybrid vehicles currently command higher capital costs than internal combustion engine ("ICE") vehicles, typically resulting in a 20-120 percent higher purchasing cost. In response to the OEB's direction in the last rebasing application to engage in a more detailed cost benefit analysis between EVs, hybrid, and combustion engine vehicles[2] and to assist in investing

[2] OEB Decision and Order, EB-2018-0165 (December 19, 2019), at p. 104.

prudently across these different vehicle types, Toronto Hydro analyzed various phasing and cost options for electrifying its fleet and the results of this analysis informs Toronto Hydro's procurement strategy for EVs and hybrid vehicles. In procuring electrified or hybrid vehicles, Toronto Hydro considers factors including safety, incremental annual capital cost and operating cost impacts, availability, similarity between electric and hybrid models to existing vehicles, ease of maintenance and operation, familiarity with the technology, scope 1 GHG reductions, and all associated change management considerations.

A paced approach for replacing ICE vehicles with EV and hybrid models results in a much more balanced capital expenditure profile than adopting more aggressive fleet decarbonization strategies. This paced approach helps Toronto Hydro meet its decarbonization goals, while minimizing the risk of stranded assets through the prudent management of OM&A costs (e.g. against possible increases from vehicles in poor condition and overdue for replacement), and capital expenditures (e.g. in respect of vehicles that are still in good condition despite being close to their projected end-of-life). Alternative approaches, such as aggressively replacing ICE vehicles in short order to accelerate decarbonization to a greater degree, would likely hamper the utility and its ratepayers from achieving optimum value from existing vehicles that are still in good condition, as such an approach would likely require such assets to be replaced sooner, meaning their total cost of ownership could not be optimized.

Conversely, an overly conservative approach attempting to extend the life of aging or poor-condition ICE vehicles and significantly defer capital investments in electric and hybrid vehicles would result in an increase in operational costs. A paced and balanced replacement strategy would help Toronto Hydro replace existing vehicles closer to their optimal lifetime total cost of ownership, while meeting its decarbonization goals. This approach would balance the utility's year-over-year capital expenditures and would not require significantly more capital investments compared to a like-for-like replacement strategy that that does not aim to meet decarbonization goals.

Toronto Hydro will prioritize EV options if they are able to meet the requirements necessary for users to carry out distribution work and other day-to-day operations. If EV options are not available in the market or the operational feasibility of deploying EVs for a particular function remains under analysis, the utility will consider hybrid options. If hybrid options are not available in the market, the utility will pursue ICE options. In view of the size and dense urban nature of its service territory, Toronto Hydro estimates that all vehicle types (ICE, EV, and hybrid) would perform at the same level of reliability.

The utility is currently exploring fully electric heavy-duty vehicles in small numbers and on a pilot basis as the market availability of these types of vehicles remains relatively low and further field experience is required to analyze the reliability and performance of these units under normal and emergency operating conditions. While the pilots continue, Toronto Hydro has adopted hybrid configurations of heavy-duty vehicles by having some vehicle components run off additional batteries. For example, some heavy-duty vehicles use electric power take-off ("PTO") aerial boom units and auxiliary batteries instead of gasoline- or diesel-burning generators for operating tools.

E8.3.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Ensuring crews have the necessary vehicles and equipment to perform distribution work when required; and ○ Ensuring that the fleet is in good operating condition and assets are replaced before critical equipment failures arise, which may necessitate lengthy and costly offsite repairs.
Environment	• Contributes to Toronto Hydro's environmental objectives by reducing GHG emissions associated with fleet fuel consumption through: ○ Opting for hybrid and electric vehicles and biofuels while maintaining fleet reliability ○ Implementing anti-idling technology, GPS reporting used to drive changes in driver behaviour, and the use of biofuels.[3] ○ A targeted 8-10 percent reduction in tonnes CO_2 emission by the end of 2029.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by implementing vehicle packages and accessories that help ensure employees are working safely with minimal exposure to hazards.
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives as measured by the total cost and efficiency measures by: ○ Managing fleet and equipment assets to the lowest overall lifecycle cost; and

[3] The use of technology to drive these results is limited by funding and classes of vehicles where the return on investment is justifiable.

	○ Mitigating fuel expense by aiming to reduce fuel consumption through a combination of utilizing hybrid and electric vehicles; idling-reduction technologies; and replacing vehicles at the point of lowest lifecycle cost.

E8.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Safety, Reliability, Business Operations Efficiency

E8.3.3.1 System Maintenance and Capital Investment Support

The trigger driver for the Program is Toronto Hydro's need for safe and reliable vehicles that support the utility's capital work and system maintenance during the 2025-2029 rate period and beyond. The utility requires access to vehicles and equipment that meet current and future functional requirements to transport employees and materials to and from job sites, perform distribution work onsite, and provide shelter and working areas for workers on site. Vehicle uses on job sites include lifting and positioning material, storing material, preparing material for installation, acting as a planning station, and serving as shelter. Fleet vehicles must be available to support these work functions in a safe, reliable, and operationally efficient manner.

Toronto Hydro's fleet consists of several vehicle types that are designed to meet the utility's evolving portfolio of requirements and support other investment programs and the utility's distribution work. Heavy duty vehicles are required to transport equipment for distribution work. Light duty vehicles are required to facilitate the engineering and management functions of distribution work. Associated equipment assets for these vehicles are used to perform lifting and towing, and include operator safety implements, such as network protection relays, rubber gloves, and gas monitors.

During the 2020-2024 rate period, the average age of assets in the utility's fleet has been trending slightly upwards. This is primarily due to the decommissioning and replacement of some vehicles after their optimal replacement age, delayed due to recent global supply chain issues affecting the availability of new vehicles for replacement and the need to retain a sufficient complement of vehicles enabling conformance with organizational health and safety requirements (e.g. worker social distancing) during the COVID-19 pandemic. The projected average age of the fleet for the 2020-

2024 rate period is 4.9 years. The projected average age of the fleet for the 2025-2029 rate period is 5.4 years.

E8.3.3.2 Safety

Toronto Hydro's investments mitigate the risk of deficiencies and safety hazards to the public and Toronto Hydro employees from structural, component, and electrical failures. Mitigating the following safety risks requires sufficient funding to keep the utility's fleet in good operating condition.

1. Corrosion

Managing corrosion and replacing corroded vehicles is important to maintain fleet reliability and safety. The utility's vehicles are continuously used throughout the year and spend the majority of the time outdoors in direct exposure to the weather and external elements. Humid weather and road salt can lead to corrosion that damages and weakens a unit's frame over time. As shown in Figure 2 and Figure 3 below, corrosion can also make vehicle body parts weak and brittle. Brittle panels are subject to breaking, leaving sharp edges or presenting a potential fall hazard if the rusting occurs on a step, handle, or vehicle floor.

Corrosion of a vehicle's frame can lead to the frame breaking during a lift operation, cable pull, or material loading. Frame weakness can also decrease a vehicle's ability to withstand crashes and jeopardize the safety of the operators and the general public. Corroded vehicle components can also impact safety and are difficult and costly to repair. For example, a corroded transmission line that ruptures could result in a seized transmission. If this occurs while in motion, the operator is at risk of losing control of the vehicle.

Figure 2: Corrosion on Cube Van Steps

Figure 3: Axle Corrosion on Bucket Truck

2. Hydraulics

Similar to the impact of corrosion, unaddressed hydraulic problems mediate in favour of vehicle replacement, as repairs are costly, take the vehicle out of service, and indicate that the vehicle's overall condition has deteriorated. Components such as the hydraulic hoses running through an aerial boom cannot be directly inspected at service intervals. As the hoses age, they become less flexible and more brittle. Hose failure results in hydraulic fluid leaks to the environment and could also render aerial buckets on bucket trucks inoperable or cause a failure while an employee is operating the bucket. Rescuing a trapped employee from a failed aerial bucket presents a potential safety risk to the employee in the bucket, other field employees who are assisting with the operation, and the public.

3. Electrical

The maintenance of appropriate fleet age and condition is important to protect electrical circuitry from causing safety and reliability issues. The longer a vehicle is in service, the more likely electrical failure becomes. Electrical failures could lead to the malfunctioning of auxiliary safety lighting systems and onboard equipment required for field staff to perform their distribution functions.

E8.3.3.3 Reliability

Toronto Hydro's fleet investments ensure the reliability of the utility's distribution operations and the execution of its capital and maintenance programs. As vehicles age, they become increasingly unreliable and require more maintenance. In addition, even with regular maintenance, vehicles are more likely to fail while in use or will need to be held out of service for repairs following an inspection. Furthermore, parts availability for aging vehicle models decreases over time, especially as certain makes and models of vehicles become obsolete. As a result, there is an increased probability that an older vehicle will remain out of service for longer periods of time while Toronto Hydro procures the requisite parts. Unreliable or unavailable vehicles adversely impact the utility's ability to provide acceptable levels of reliable service to customers and result in lost productivity and business disruption.

E8.3.3.4 Business Operations Efficiency

Toronto Hydro tracks its fleet utilization by measuring "days used", meaning that the utility measures whether a given vehicle is used on a given business day, compared against the total number of work days in a year. This measurement produces both individual scores for the vehicle and aggregate scores for the fleet. The utility uses these scores to inform its investment planning and to optimize the use of its existing assets, by prudently maintaining a sufficient number of vehicles for use by business units as required, without retaining more vehicles than necessary. Optimal fleet utilization also allows for the regular maintenance of vehicles without interrupting distribution operations.

Toronto Hydro changed its fleet utilization methodology from "standard utilization percentage" to the current "days used" metric in the 2020-2024 rate period after monitoring both methods for efficiency and accuracy. The utility chose this updated measure of fleet utilization because it more accurately reflects vehicles' availability and reliability on a day-to-day basis compared to the previous utilization metric which omitted usage during overtime hours and did not account for usage during shift changes. It also allows the utility to track and measure the usage of particular vehicles against other vehicles of the same class within the fleet, to track on an ongoing basis if vehicles can be re-allocated to different departments and areas of distribution work to increase productivity. The below figure demonstrates Toronto Hydro's historical fleet utilization over 2018-2023 and estimated utilization over 2024-2029. The utility tracks utilization in two separate tiers of "Core Fleet" (distribution operations vehicles) and "All Fleet" (Core Fleet + pool vehicles, specialized support vehicles, etc.).

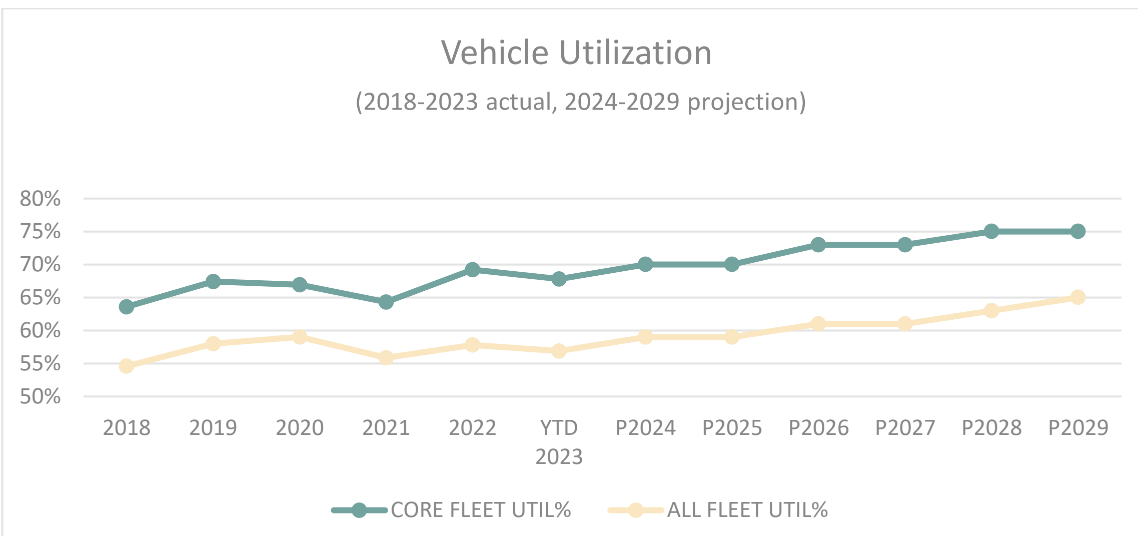

Figure 4: "Days Used" Vehicle Utilization Metric

Early in the 2020-2024 rate period, Toronto Hydro experienced countervailing factors exerting both upward and downward pressure on the vehicle utilization metric. The utility's ongoing decommissioning of underutilized vehicles within its fleet going into 2020 helped improve utilization rates. However, the onset of the COVID-19 pandemic and the health and safety measures that Toronto Hydro adopted (such as social distancing measures that limited each vehicle to a single occupant) required the utility to retain fleet vehicles that otherwise would have been taken out of service. This increased fleet utilization rates during the early stages of the pandemic, and decreased rates as social distancing measures were phased out prior to retiring the excess fleet vehicles. Toronto Hydro expects its utilization rate to continue to improve as effects of the pandemic subside and the utility rationalizes its vehicle count following the discontinuation of related measures.

The "All Fleet" utilization score includes highly specialized vehicles such as elevated bucket trucks for unique applications, emergency vehicles, Fleet and Facilities support vehicles, and pool vehicles that are crucial to the utility's operations because they provide support to specialized operations and are equipment that cannot be procured on a short-term rental basis. Toronto Hydro uses these vehicles during emergency situations such as power outages and mutual aid excursions, and to provide alternatives during extensive vehicle repairs or for other short-term requirements. These scenarios require a complement of pre-equipped vehicles to be readily available for emergency or rapid response.

The "Core Fleet" represents approximately 75 percent of Toronto Hydro's total fleet; the majority of these vehicles are assigned directly to Distribution Operations teams to help support day-to-day business operations. The core fleet includes a wide spectrum of light and heavy-duty vehicles.

E8.3.4 Expenditure Plan

Table 4: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Heavy Duty Vehicles	5.1	1.1	8.8	5.1	4.8	7.0	5.3	7.7	5.8	3.2
Light Duty Vehicles	1.3	1.1	5.5	1.2	1.1	2.0	4.4	0.9	1.9	4.4
Equipment	0.1	0.1	1.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Total	**6.5**	**2.3**	**15.5**	**6.4**	**6.0**	**9.2**	**9.9**	**8.8**	**7.9**	**7.8**

Toronto Hydro's capital expenditure and asset replacement planning for the Program begins several years in advance in order to account for lead times and to effectively procure vehicles. The utility uses the Strategy to identify candidate vehicles for future replacements, plan the pace of procurement, and identify the optimal point at which to replace a given asset based on ongoing assessment of its condition. If Toronto Hydro does not receive the requested funding and is unable to make the planned investments over the 2025-2029 rate period, its fleet will incur increasingly high operational costs, will be less reliable, and will pose a greater risk to safety, to ongoing distribution operations, and to the execution of capital programs.

As shown below in Table 5 below, Toronto Hydro shuffles asset replacements across the five-year rate period as necessary to balance spending year over year and prudently manage costs. Replacing assets in batches and optimizing spending in a given year makes it easier for the Program to balance work throughout the lifecycle of the vehicle. Table 6 shows the parameters and factors by vehicle class that inform Toronto Hydro's prioritization of its long-term capital planning for fleet and equipment assets.

Table 5: Replacement Costs[4] for Fleet by Segment for the 2025 to 2029 Period ($ Millions)

Description	2025		2026		2027		2028		2029		Total Cost
	No.	Cost	No.	Cost	No.	Cost	No.	Cost	No.	Cost	
Heavy Duty	13	7.0	13	5.3	23	7.7	11	5.8	12	3.2	**29.0**
Light Duty	18	2.0	26	4.4	10	0.9	12	1.9	40	4.4	**13.6**
Equipment	2	0.2	1	0.2	1	0.2	1	0.2	10	0.2	**1.1**
Total	**26**	**18.6**	**39**	**8.4**	**35**	**8.8**	**22**	**9.1**	**52**	**2.4**	**43.7**

Table 6: Factors Influencing Capital Planning by Asset Class

	Functional Criticality	Procurement Time	Average Cost/Unit ($M)	Degree of Customization
Heavy Duty Vehicles	High	24-36 months	$0.32	High
Light Duty Vehicles	Medium	10-18 months	$0.06	Medium
Equipment	Low	6-12 months	$0.07	Low

Heavy duty vehicles take the highest priority in planning because they are the costliest and take the longest to procure, with timelines typically around 24-36 months. The procurement process begins by determining the specifications of vehicles and continues to with the delivery of the units. In planning its heavy-duty fleet, Toronto Hydro engages multiple vendors to determine the feasibility of particular vehicle configurations and ensure all vehicle components can work as intended.

[4] These costs are inclusive of all up-fitting necessary for the job, such as storage bins, partitions, racking, lighting, additional power supply, and any other aftermarket additions required in a particular light duty vehicle.

The procurement of light duty vehicles follows the same procurement steps, but the timelines are typically shorter. Light duty vehicles usually feature more standardized specifications as they are typically used for transporting people or equipment, and are not used to perform distribution work. Thus, it takes the utility less time to determine the specifications of the light duty vehicle and prepare it for operations once acquired, since such vehicles typically require fewer components to be built or installed.

E8.3.4.1 Equipment

Toronto Hydro's equipment investments over the 2025-2029 rate period are targeted to ensure safety for fleet operators and to implement decarbonization measures where options for switching to EVs or hybrid vehicles are limited. These investments include anti-idling technology, GPS units, laptop mounts installed in vehicles, trailers, and lift equipment, described in greater detail below. The utility replaces equipment on a reactive or "run to fail" basis because equipment generally has a long lifespan, procurement times are quick, replacements are available on the market, equipment failure poses a low safety risk, and variability in use makes it difficult to predict when a given piece of equipment will require replacement.

Table 7 below shows the forecasted costs of replacing equipment on a reactive basis. Toronto Hydro assesses equipment every six months through a preventative maintenance review and determines respective replacements based on units' condition and performance.

Table 7: Equipment Replacement Costs For 2025 to 2029 Period ($ Millions)

	2025	2026	2027	2028	2029	Total
Equipment	0.22	0.22	0.22	0.22	0.2	1.1
Total	**0.22**	**0.22**	**0.22**	**0.22**	**0.22**	**1.1**

The utility's investments in telematics and anti-idling systems help the utility monitor and continuously improve vehicle idling, utilization, driver safety, and diagnostic maintenance. Some heavy-duty diesel vehicles are equipped with GRIP anti-idling technology to reduce idling, which increases the vehicle's lifespan and decreases GHG emissions. The utility's purchase contracts require vehicle vendors to comply with these specifications. The anti-idling system manages, monitors, and provides real-time data on battery voltage, coolant, temperature, idling, anti-theft mode, and engine starts and stops. It also provides reporting on driver behaviour that helps reduce speeding and harsh braking, which increases fuel efficiency. The use of telematics GPS hardware and software provides several benefits, including real-time tracking of vehicle locations and maintenance indicators,[5] aiding customer complaints investigations and claims by enabling access to historical tracking of the entire fleet and history of vehicle location, providing speeding notifications based on local speed limit and set data, and the management and creation of zones based on work centre locations to optimize vehicles' arrivals and departures.

Other onboard equipment includes laptop mount kits for ruggedized laptops used in the field, equipped with pedestal, docking station, and wiring needed to power devices. These mounts are installed in most light and heavy-duty vehicles to facilitate the ergonomically safe use of laptops for onsite crew inspections, site visits, and other situations without requiring field crews to drive back to a work centre and file paperwork. Ergonomic features (such as dock tilt, spring loaded, telescopic, and adjustable base) and periodic risk assessments help enhance user safety and performance over time.

Figure 5, below, shows views of a steel lap mount installed in a cube van which includes a pedestal bolted to the base of the cab along with a docking station, battery protector, and antenna.

Figure 5: Laptop Mount Installed in Cube Van

E8.3.5 Options Analysis / Business Case Evaluation ("BCE")

Toronto Hydro considered three options for investments in the Program over the 2025-2029 rate period. The first, managed fleet deterioration, entails a fleet replacement strategy that would increase the average vehicle age by approximately 5-7 percent across the fleet. The second, sustained fleet replacement, entails replacing vehicle assets at the optimal age as outlined in the

[5] For example, engine light on, fuel tank, battery voltage, tire air, GPS not reporting/working, unplugged devices, idling, zoning, trip history, and PTO used for commercial vehicle operation registration ("CVOR") units.

Strategy, i.e. when the lifecycle costs of a given vehicle are the lowest. The utility is proposing to follow this option, as it enables the utility to maintain vehicle availability and reliability, make process towards decarbonization goals, meet customer expectations and facilitate the execution of the utility's investment plan. The third approach would entail improving the lifecycle of vehicles by one year in order to improve vehicle reliability and availability, and would pace the majority of the utility's investments to decarbonize its fleet into the upcoming rate period.

E8.3.5.1 Option 1: Managed Fleet Deterioration

This option delays heavy duty vehicle replacement to one year later than recommended by the LCA, subject to assets' actual condition assessments. However, Toronto Hydro would not delay the procurement of light duty units in order to continue making progress on vehicle electrification in accordance with the utility's Net Zero 2040 Strategy.

Overall, this option would translate to an approximately 5-7 percent increase in the average vehicle age across the fleet. Under this option, the Program's objective would be to ensure that the vehicle replacements continue at an acceptable pace without materially compromising the reliability and safety outcomes. The investment plan under this option, would contemplate replacing all light duty vehicles and ten heavy duty vehicles with electric or hybrid vehicles.

As this option is based on a reduced capital expenditure profile, it would likely restrict Toronto Hydro's flexibility to scale fleet investments up or down in accordance with the utility's needs. This approach also risks increasing labour costs and vehicle downtime due to aging vehicles requiring more frequent maintenance and more support compared to the other options. To the extent that these challenges cause fleet capacity issues, there may be also delays of or interruptions to capital work, system maintenance, and outage restoration, adversely affecting a number of safety, reliability, and customer service outcomes.

More specifically, this option would have the following consequences:

- Unit field failures will likely increase as vehicles age and adversely affect field crew productivity. In some cases, unit field failures may render Toronto Hydro unable to conduct system maintenance and capital work as planned. This will lead to higher operational labour and support costs (such as permits, penalties for late work completion, additional fuel on account of more frequent trips to and from a work location, etc.).

- The severity of asset failures is likely to increase and these failures could potentially become more catastrophic, leading to safety risks, injuries, damage to property or equipment, and environmental spills.
- Toronto Hydro's operating costs for repairs are likely to increase as parts fail and are replaced. As a vehicle ages, parts will likely become less available, resulting in increasing costs with respect to their purchase.
- The utility may have to increase its vehicle count to maintain similar vehicle availability levels in order to deliver equivalent service levels to customers. This is because as vehicles age, time out of service will likely also increase due to increasing repair challenges that result from an aging fleet (such as deteriorating components and the consequent need for more significant repairs). To ensure that vehicles are available for use, Toronto Hydro would likely require the use of 'spare' vehicles should the main service vehicles become unavailable on account of maintenance or repairs. In addition, the utility may have to rent new equipment for vehicles at a significant cost.
- The replacement of vehicles that have reached a total state of failure may require long lead times (e.g. up to 30 months for the purchase and delivery of specialized vehicles). During this period, Toronto Hydro's ability to perform capital work and system maintenance may be impaired or delayed if alternate vehicles cannot be sourced internally or through renting or leasing externally.

E8.3.5.2 Option 2: Sustained Fleet Replacement (Recommended Option)

This spend option replaces vehicle assets at the optimal replacement age. As discussed in the Strategy, Toronto Hydro determines a vehicle's optimal replacement age by using the LCA as a baseline indicator, with adjustments based on the assessment of individual assets' condition. Under this option, the Program's objective would be to ensure that vehicle replacements occur at the point in time where the lifecycle cost of ownership is lowest. The electrification strategy under this option would involve replacing all light duty units and 15 heavy duty units with electric or hybrid vehicles.

The proposed vehicle replacement pace under this option would allow the sustainment of the fleet at the optimal age profile and result in a lower average age of vehicles compared to the managed fleet deterioration option. This approach would optimally balance capital expenditures against the need to ensure the reliability and availability of fleet and equipment assets. In addition, this option would optimally support the utility's progress towards its decarbonization goals.

This option would have the following consequences:

- Toronto Hydro will replace vehicles according to asset management criteria that will optimize the average total cost of vehicle ownership over time;
- Overall vehicle reliability will improve, resulting in less downtime, fewer vehicle failures, and improved field crew productivity;
- Fleet vehicle and equipment performance will improve;
- Overall safety of fleet vehicles will improve thanks to enhanced safety features found in newer vehicles; and
- Fuel efficiency will improve, leading to reduced GHG emissions and fuel costs.

E8.3.5.3 Option 3: Improved Fleet Availability & GHG Emissions Reduction

This spend option aims to replace fleet vehicles sooner by reducing the baseline lifecycle assumptions by one year. This would result in an approximately seven percent decrease in the average age of Toronto Hydro's fleet compared to the sustainment option. The objective of the Program under this option would be to improve vehicle reliability and availability. By replacing vehicles earlier, the utility would avoid the more significant and costlier repairs typically seen in the final year of a vehicle's lifecycle and increase vehicle availability. For example, for certain vehicle types, the vehicle's lifecycle could be aligned with the battery warranty to avoid significant battery repair costs, which often exceeds the value of the vehicle itself when nearing end of life. The improved condition of fleet vehicles would also result in overall lower operational expenses due to less maintenance needs and the lower likelihood of having to rent vehicles to substitute for out-of-service fleet vehicles. The resulting higher reliability levels compared to other options would allow Program resources to better focus on continuous improvement since vehicle conditions will remain at more consistent levels across the fleet. This option also aims to accelerate the electrification of the fleet by replacing all light duty vehicles and 20 heavy duty vehicles with electric or hybrid vehicles in accordance with Toronto Hydro's Net Zero 2040 Strategy.

This option would have the following consequences:

- Pre-emptive mitigation of age-related safety risks and associated repair costs;
- Improved reliability levels reducing reliance on external repair services for more significant repairs;
- Better availability of vehicles to perform capital work, system maintenance, and outage restoration during extreme weather and other emergency events; and

- Potential logistical challenges with putting greater numbers of new vehicles in service and disposing of decommissioned vehicles.

E8.3.5.4 Evaluation of Options

Toronto Hydro proposes to proceed with Option 2, the Sustained Fleet Availability approach, as it is the most cost-effective option to manage Toronto Hydro's vehicle fleet while providing the opportunity to meet Toronto Hydro's Net Zero goals. These aims help ensure asset reliability, customer service, and contribute to employee and public safety.

Replacing the vehicle fleet on a Managed Deterioration basis (Option 1) will not only adversely affect field crew productivity and hamper planned system maintenance and capital work, but also result in upward pressure on vehicle maintenance and repair costs. In comparison to Option 2, the Sustained Fleet Replacement scenario, this option allows for further investment in electric and hybrid vehicles while also further improving fleet age profiles to enhance reliability and cost-effectiveness.

The Improved Fleet approach (option 3) accelerates capital investments; but also reduces asset maintenance and repair costs. Option 3 speeds up the electrification of the fleet but does not allow for the prudent and measured evaluation of EV technology to ensure its suitability in our operating environment. Both options 2 and 3 allow us to achieve 2040 Net Zero goals.

The summary of this options analysis is as follows:

Table 8: Options Analysis Summary

Outcome Measures at End of 2029	Deterioration	Sustainment	Improvement
Option Cost ($M)	34.35	43.69	47.45
Average Fleet Age (years)	6.7	5.4	5.0
GHG Emissions (tonnes CO2)	1222	1177	1034

E8.3.6 Execution Risks & Mitigation

There are three primary execution risks inherent in the Program: (i) escalating vehicle costs; (ii) increasing procurement lead times; (iii) supply and availability of fully electric heavy-duty vehicles. Vehicle costs have been escalating since the onset on the COVID-19 pandemic due to supply chain issues in getting parts and vehicles delivered; the weakening of the Canadian dollar versus the American dollar which impacts most heavy duty vehicle chassis' costs; semiconductor shortages impacting the availability of both light and heavy duty vehicles; automotive industry production and manufacturing cuts due to the pandemic and changes in the workforce; and the unpredictability and longer lead times for acquiring fully electric vehicles.

As a mitigation strategy, Toronto Hydro issues multi-year tenders with limitations on cost increases per year where possible and provides vendors the option to update pricing and delivery schedules for EV and hybrid options on tender submissions as they become available. In addition, where possible, the utility chooses Canadian suppliers to maximize repair efficiency where they are the lower cost bidder. The Program has also extended planning lead times for procurement to accurately reflect the most current delivery expectations provided by vendors given supply chain, production, and electrification constraints. For more information on the more general mitigation measures the utility has adopted with respect to procurement risks, please refer to the Supply Chain Services program in Exhibit 4, Tab 2, Schedule 15.

E8.4 Information Technology and Operational Technology Systems

E8.4.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 256.6	**2025-2029 Cost ($M):** 301.3
Segments: IT Hardware, IT Software, and Communication Infrastructure	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Operational Effectiveness - Reliability, Customer Focus, Public Policy Responsiveness, Operational Effectiveness - Safety, and Financial Performance	

The Information Technology and Operational Technology Systems (IT/OT) program (the Program) invests in hardware, software, and communication assets that provide critical support to Toronto Hydro's customer and business-facing services.[1] Toronto Hydro relies on IT/OT systems to execute capital and operational programs, including customer-facing and operationally-critical functions. The investments proposed in this Program were developed in accordance with Toronto Hydro's Information Technology Asset Management Strategy and Investment Planning procedures (Strategy) and are intended to mitigate risks to reliability, cybersecurity, and the utility's business operations.[2]

The Program's objective is to provide reliable technology solutions and services to support Toronto Hydro's business functions, including effective and reliable service to customers, safe and efficient management and operation of the distribution system, compliance with legal and regulatory requirements, and sustainment of the utility's long-term financial viability.

The Program consists of the following three segments:

- **IT Hardware**: includes the core back end infrastructure assets (e.g. servers, local area networks and data storage/centres), security appliances and endpoint assets (e.g. desktop computers, laptops, printers, smart phones, and tablets) that support Toronto Hydro's day-to-day operations and core systems;

[1] Note: Operational Technology refers to hardware and software that detect or cause a change through the direct monitoring and/or control of physical devices, processes, and events in the enterprise. See: Gartner Inc., IT Glossary, Operational Technology Definition.
[2]Exhibit 2B, Section D8.

- **IT Software**: includes software applications that provide process improvements and operational capabilities to a range of customer-facing and business functions; and,
- **Communication Infrastructure**: includes assets that enable the monitoring and control of distribution communication infrastructure, including fibre-optic assets and wireless Supervisory Control and Data Acquisition (SCADA) infrastructure.

E8.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Implementing and maintaining a range of customer service and communication tools and systems; ○ Improving the customer experience of interacting with the utility through digital platforms; and ○ Supporting accurate and timely communication with customers during prolonged power outages.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Maintaining the availability of modern, reliable and secure enterprise-wide IT/OT systems that support efficient distribution system management; ○ Supporting outage restoration efforts by ensuring that system operators have the necessary IT/OT tools to promptly identify incidents, develop effective resolution plans and communicate with operational teams; ○ Enhancing IT/OT systems to enable remote equipment monitoring and operations capabilities; and ○ Supporting the creation and maintenance of cyber security controls to mitigate against potential vulnerabilities and threats that may jeopardize the safe and proper functioning of IT/OT assets.

Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by: ○ Providing the technological infrastructure framework required to improve the distribution system's ability and capacity to evolve and meet emerging needs (e.g. the integration of distributed energy resources, new load types such as electric vehicles, and increasing reliance on energy flow data); and ○ Providing the technological infrastructure required by the utility to continuously improve its processes and adapt to evolving legal and regulatory requirements, business conditions, and customer expectations.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency (TRIF) by: ○ Enabling the constant monitoring of substation and field assets to prevent asset overloads and failures, which might result in injuries to anyone in the close proximity of the equipment; and ○ Maintaining the effectiveness and availability of IT/OT Systems that support the utility's safety performance (such as SCADA, Automated Vehicle Locator, Radio, and Network Management System).
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by ensuring that the Tier 1 IT systems are available and reliable in support of efficient and accurate customer and market invoicing and settlements and financial reporting and recordkeeping.[3]

E8.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Cyber Security Risks, Regulatory Compliance, Functional Obsolescence, Modernization, and Electrification

[3] Exhibit 2B, D8. Tier 1 applications enable Toronto Hydro's critical business operations and support company-wide business processes. They are functionally integrated with other applications, and are supported by complex, highly redundant underlying infrastructure such as databases, middleware, storage, and network.

The Program supports Toronto Hydro's core operations and business processes, and enables the safe and efficient execution of the utility's capital and operational programs. The utility relies on its IT/OT systems to manage and operate the electricity distribution system, satisfy its obligations to customers, comply with existing and emerging legal and regulatory requirements, and provide the technological infrastructure to continuously improve and adapt its business processes to evolving industry trends such as the pace of electrification increases and the resulting changes in customers' needs and preferences.

E8.4.3.1 IT Hardware

Toronto Hydro's IT hardware must be renewed on a regular basis to ensure the ongoing reliability of systems that support customer-facing services and core distribution operations by maintaining a low risk of failure. The utility's IT hardware also ensures a strong cybersecurity posture to mitigate against potential vulnerabilities and threats that may jeopardize the safe and proper functioning of IT/OT assets.

IT Hardware segment consist of two subsegments:

- IT Hardware Infrastructure;
- IT Cybersecurity Practice.

1. IT Hardware Infrastructure

Toronto Hydro employs many software applications to automate processes and efficiently execute a variety of daily tasks such as preparing customers' bills and dispatching crews to respond to outages. Renewing the underlying IT Hardware on a routine basis is essential to ensure that the software applications remain available. IT Hardware Infrastructure refers to the environment supporting Toronto Hydro's entire Information Technology ecosystem. It aims to provide adequate sizing, availability, scalability, performance and security of the environment to fit business application needs, while ensuring obsolescence prevention and vendor supportability. IT infrastructure assets are classified as either Endpoint Assets or Core Infrastructure Assets.

Endpoint Assets are the assets that the end-user interfaces with to execute, process, complete and review business tasks and operations. These include computing assets (e.g. desktops, laptops, and tablets) that support the execution of business processes, data transactions and analysis, as well as printing assets (e.g. printers, plotters, and photocopiers) that translate electronic documents like engineering drawings and contracts onto paper. Both are relied upon extensively by Toronto Hydro's users to execute daily work across the utility.

Core Infrastructure Assets are responsible for the computation, storage, and communication necessary to support IT systems. Servers manage access to centralized resources and services in the network and security appliances secure the network from unwanted traffic. Storage assets enable the secure retention of digital data such as customer information, and include disk and flash arrays, which store records for access by servers. Communication assets facilitate the exchange of data within and between the core backend assets and the endpoint assets, so that users can access information from a central IT system. Network and telephony assets enable computers, services, and storage devices to exchange data and manage communication services. Figure 1 depicts the typical structure and dependency of IT infrastructure assets.

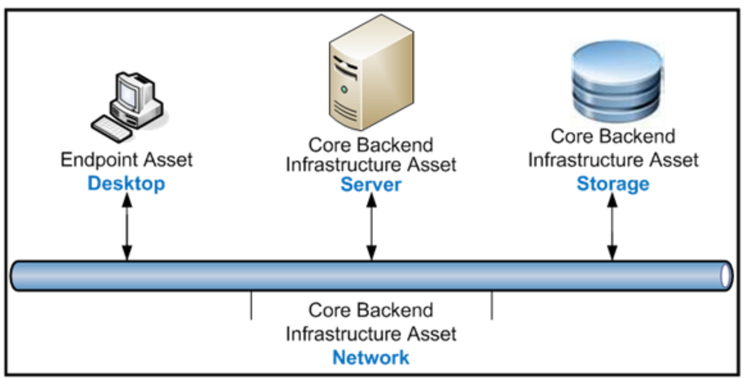

Figure 1: Typical Endpoint Asset to Core Infrastructure Relationships

IT infrastructure environment forms the foundational technology layer upon which all other IT functions and business processes are deployed, including IT Cyber Security, IT Operations, IT Software and company-wide resourcing and workforce management functions. Operational efficiency improvement opportunities are continuously explored and evaluated. These include provisioning more powerful hardware to allow for denser resource deployment and streamlining of systems architecture to fully realize technological potential.

The lifespans of IT infrastructure assets range from four to seven years, which are considered to be within industry norms. At the end of its lifecycle, hardware assets' risk of failure increases significantly, potentially impacting core business processes. To determine the refresh cycle for existing hardware, Toronto Hydro maintains an inventory of infrastructure assets that includes technical details and lifecycle information such as date of implementation and end of vendor support. This approach ensures that IT hardware assets are up-to-date and available to support the effective and efficient execution of the utility's operations.

Adhering to this approach, approximately 90 percent of Toronto Hydro's core backend infrastructure, and 100 percent of its endpoint assets will need to be replaced during the 2025-2029 rate period. This includes data and voice network routers, switches and appliances, storage network switches, storage arrays, data backup appliances, file storage appliances, UNIX, Linux and Windows servers, monitoring appliances, uninterruptable power supplies and others. IT hardware infrastructure assets support a number of customer service functions. In 2023, approximately 320,000 customers use the online electronic billing function and have accounts that provide key self-serve functions, such as management of account details, customer moves, payment options, and landlord information as of 2022. IT hardware assets also support a number of customer interfacing applications and processes delivered via telephony through the Toronto Hydro Call Centre. If hardware assets supporting these functions were to fail, customers would be unable to access these systems, and could experience significant delays in completing routine transactions. This would impact overall customer satisfaction and may result in increased volume of calls and complaints to Toronto Hydro's Call Centre. Higher call volumes will also limit Toronto Hydro's ability to meet Ontario Energy Board (OEB) prescribed service quality metrics such as First Contact Resolution.

IT hardware supports systems are also used to manage field crews and respond to outages, and thus are critical to the utility's ability to conduct day-to-day operations and ensure reliability. By providing access to real-time data for crew availability, geographical location of outages and crews, these systems enable Toronto Hydro to deploy crews in a timely and effective manner and restore power to customers faster. In the event of core infrastructure failure, the functionality of these applications would be impaired, leading to longer outage response times and poor customer satisfaction. Longer outage response times will negatively impact Toronto Hydro's ability to meet OEB prescribed reliability performance standards such as System Average Interruption Duration Index (SAIDI).

IT hardware also underpins the utility's environmental, health, and safety processes across its work centres and job sites. Such processes range from completion of site conditions and safety forms, review of Material Safety Data Sheets, safety and environmental audits, and incident and claims investigations. In the event of IT hardware failure, employees may not have access to the information required to make informed decisions about environmental and health and safety issues. This may be compromising workers' safety or contributing to non-compliance with applicable OEB requirements and Utility Work Protection Code.

IT hardware investments are planned and implemented based on existing and future utility needs and operational requirements. This allows Toronto Hydro to execute its plans and programs securely and efficiently in pursuit of its short-term and long-term objectives. IT hardware standards are regularly reviewed, assessed, and implemented based on the utility's existing and ongoing requirements from operational, regulatory and customer service perspectives. In order to continuously adapt its standards and processes to meet these needs, Toronto Hydro requires ongoing investments in its IT hardware assets.

2. IT Cybersecurity Practice

Cybersecurity practice is responsible for the ongoing protection of the organization from all external and internal information security threats. Growing industry reliance on IT as a key business enabler also carries the increased risk of cybersecurity exposure. Global cybersecurity threat landscape is constantly evolving, with attacks ranging from social engineering to destructive ransomware attacks to nation-state backed advanced persistent threats. Cybersecurity has been identified as one of the growing corporate risks. As such Toronto Hydro is continuously investing in cybersecurity controls to monitor cybersecurity threats and develop a robust response to cybersecurity breaches which serves to minimize the potential damage to enterprise assets, data and brand reputation. The primary role of the cybersecurity practice is maintaining a strong cybersecurity posture to mitigate against potential vulnerabilities and threats that may jeopardize the safe and proper functioning of IT/OT assets. Cybersecurity practice includes a combination of Run, Grow and Transform (RGT) investments, as per Gartner's RGT model.

The Run program is primarily centered around the maintenance and organic growth of existing Cyber Security capabilities. From the Threat, Risk and Compliance (TRC) perspective, this includes the orchestration of recurring enterprise IT asset security patching as well as lifecycle upgrades of perimeter and endpoint security controls, such as firewalls, Intrusion Prevention Systems (IPS) and malware protection software. Identity & Access Management (IAM) aspect of the Run program is aimed at ensuring that the organization maintains secure, role-based access to resources, properly logged for auditing and forensic analysis purposes.

The Grow program expands baseline cybersecurity capabilities, through the adoption of advanced threat protection technologies and user education processes aimed at curbing the exposure to social engineering attacks. Grow initiatives are focused on the expansion and strengthening of existing protection capabilities, through the investment into advanced technologies, such as behavioral Endpoint Detection and Response (EDR) solutions to prevent zero-day attacks, perimeter and endpoint Data Loss Prevention (DLP) solutions to stop information exfiltration, and intelligent email phishing prevention solutions.

The Transform program explores pioneering technologies and cyber-defense mechanisms to attain higher protection levels for digital assets, safeguard customer and employee privacy and install stakeholder confidence. Falling under this program are initiatives such as proactive threat hunting, persistent attack surface management,[4] honeypots,[5] network detection & response, attack pattern recognition and micro-segmentation.[6] These initiatives are aimed at limiting corporate exposure to and damage from advanced threats, such as zero-day ransomware attacks.[7]

Investments in cybersecurity solutions are required to ensure that current systems, applications and endpoints can continue to operate reliably and with minimal risk exposure to cyber threats in response to evolving threat landscape, and regulatory compliance obligations.[8] This ensures that the existing security controls are continuously enhanced and matured to meet the cyber resiliency requirements. Cybersecurity requirements need to detect uncertainties in the environment such as pandemic driven infrastructure changes, heightened monitoring requirements, Advanced Persistent Threats (APT) related to the geopolitical situation, and exposure to critical zero-day security vulnerabilities. In order to build security requirements that can respond to these uncertainties, Toronto Hydro plans to make continuous investments into its robust cyber security infrastructure using layered Defence-in-Depth model to ensure the protection of both IT and OT assets. These investments will help the utility to develop a strong cybersecurity posture which will be essential in

[4] The continuous discovery, analysis, remediation and monitoring of cybersecurity vulnerabilities and potential attacks to the system.
[5] A decoy system that is designed to look like attractive targets, and deployed to allow IT teams to monitor the system's security responses and to redirect the attacker away from their intended target.
[6] A method of security that involves dividing a network into segments and applying security controls to each segment based on the segment's requirements.
[7] A type of ransomware which exploits unknown and unprotected vulnerabilities.
[8] *Electricity Act*, 1998, SO 1998, Ch 15, Sched A,
Ontario Regulation 633/21, Section 3. Section 3 of the Regulation allows customers to submit authorizations to allow third party access to their energy data.

providing an effective response to expected increases and sophistication in emerging cybersecurity threats, due to industry shift towards electrification.

Outdated or reactive security controls and technologies pose several risks to Toronto Hydro's systems, applications, and endpoints including risks to business continuity, distribution system reliability, and financial health. Toronto Hydro is governed by a variety of legislative and regulatory requirements relating to privacy and data security, including the OEB's Cyber Security Framework. The planned expenditure for IT Hardware ensures that Toronto Hydro is able to protect its IT environment, meet security compliance requirements, provide assurance to our industry partners, customers and stakeholders, and evolve its security controls and technologies and associated processes to adapt to the emerging security threats, in response to industry shift towards electrification.

E8.4.3.2 IT Software

Investment in IT software is required in order to ensure that current applications continue to operate reliably, with minimal risk exposure to cyber threats, while also making targeted and prudent IT investments to enhance functionality. Functional improvements are also required in response to core business needs or risks in addition to meeting evolving regulatory or compliance obligations. IT software is an integral part of a modern utility. Toronto Hydro relies upon, and must maintain, various IT software systems to efficiently manage core operations and business processes and to execute planned programs relating to distribution grid operations, engineering design, construction, customer billing and corporate services (e.g. finance, human resource management, legal and regulatory).

Without these systems, a utility of Toronto Hydro's size and complexity would encounter significant challenges in operating its electricity distribution system, delivering capital programs and satisfying changes in customers' needs and expectations and other stakeholders that the organization interacts with. Ensuring reliability and availability of software plays a crucial role in supporting modernization of its business processes in response to the industry shift towards electrification, including electric vehicles (EVs), and distributed energy resources (DERs). If software is not reliable or available, it can hinder the utility's ability to enable these technologies. Moreover, if the software used to manage the grid is unreliable, it can lead to an increase in the number of outages and other disruptions, resulting in lower customer satisfaction. For example, automating customer-facing processes through enhanced channel offerings and the use of targeted digital tools can improve the overall customer experience. However, if the software used for process automation is unreliable, it can cause errors and disruptions in accessing these services, resulting in poor customer satisfaction.

Software applications deliver tangible value to customers directly through customer-facing IT services, and indirectly through the improved performance or avoided risks of business-facing platforms and solutions. To maintain a reliable and productive suite of IT Software, Toronto Hydro makes three types of investments: Software Upgrades, Software Enhancements, and Regulatory Compliance.

1. Software Upgrades

Toronto Hydro plans to upgrade all of its software applications over the 2025 to 2029 period. These upgrades will ensure that Toronto Hydro's software systems receive support from vendors, keep pace with technology changes in the industry, remain integrated with other relevant software systems, and are protected against future cyber security threats.

When IT systems have surpassed the period of extended vendor support, the vendor and the marketplace do not guarantee availability of qualified resources and expertise needed to resolve any potential issues. As a result, the failure of these systems may result in prolonged downtime, which can significantly affect the utility's operations and its ability to execute planned work programs and deliver services to its customers.

In addition, IT systems without vendor support do not receive security patches and upgrades or fixes, rendering the applications more vulnerable to cyber-attacks. These attacks attempt to tamper with normal IT system operations, gain unauthorized access to customers' and employees' confidential information, or cause a machine or network resource to malfunction or be unavailable to authorized users.

For example, the ransomware cyber attack in May 2021 on Colonial pipeline (a major fuel pipeline operator in the United States that carries gasoline, diesel, and jet fuel from refineries), resulted in the shutdown of the pipeline for several days, causing a shortage of fuel in several states and leading to panic buying and price spikes at gas stations. Colonial pipeline paid $4.4 million in ransom to the hackers to regain control of its systems[9].

In October 2021, the Toronto Transit Commission (TTC) cyberattack resulted in the disruption of multiple computer systems, including email and payroll, causing significant inconvenience for both customers and employees. The attack impacted the ability of the transit agency to communicate with its customers, as the company's website and social media channels were temporarily taken offline.[10]

In December 2022, the cyberattack on The Hospital for Sick Children had a significant impact on its operations. The attack resulted in the disruption of several services, including appointment scheduling and telemedicine. The hospital was forced to reschedule some appointments and revert to manual processes to continue providing essential medical care. The attack also affected the hospital's ability to access patient data and medical records, which posed a significant risk to patient safety and care.[11]

These events highlight the real risk and consequences of cyber intrusions and the ongoing need for Toronto Hydro to regularly upgrade its software in order to protect its systems from external attacks. A leak of Toronto Hydro's sensitive operational information could lead to and assist in malicious attempts to jeopardize day-to-day operations and, in extreme cases, the successful exploitation of a system vulnerability could cause mass outages across the grid.

The ongoing use of applications past end of useful life leads to retention and maintenance of standalone underlying components that lack vendor support lifecycles. This exposes the IT systems to security and reliability risks that could result in severe outcomes. Functional obsolescence is an additional consideration driving the need to invest in software upgrades. Finding skilled resources to ensure ongoing support optimization for legacy systems is and will become more challenging.

[9] Colonial Pipeline, Media Statement Update: Colonia Pipeline System Disruption, “online”, https://www.colpipe.com/news/press-releases/media-statement-colonial-pipeline-system-disruption
[10] Toronto Transit Commission, TTC provides update on cyber security incident, “online”, https://www.ttc.ca/news/2021/November/TTC-provides-update-on-cyber-security-incident
[11] Sick Kids, SickKids Lifts Code Grey with 80 per cent of priority systems restored, “online”, https://www.sickkids.ca/en/news/archive/2023/sickkids-lifts-code-grey-with-80-per-cent-of-priority-systems-restored

Toronto Hydro must address these risks by upgrading its applications to maintain compatibility with underlying infrastructure. Toronto Hydro categorises its Software applications as Tier 1, Tier 2, and Cloud solutions.[12]

Tier 1 applications support a variety of critical processes across the utility. These applications are functionally integrated with other applications, and are supported by a host of databases, middleware, storage and network devices. Tier 1 systems include: Geospatial Information System, Supervisory Control and Data Acquisition System, Distribution Network Management System, External Website Platform, Corporate E-Mail System, Operational Data Store, Meter Management System, Customer Information System, and Enterprise Resource Planning System. The lifecycle of Tier 1 systems is generally 5 years, after which a major upgrade is required.

The Enterprise Resource Planning (ERP) upgrade and Advanced Distribution Management System (ADMS) program are two major software upgrades planned for the 2025-2029 rate period. An ERP system is critical for Toronto Hydro, as it integrates various financial, procurement, human resource, and asset management business processes into a single system. The ADMS program will ensure continued vendor support for its key components such as the Distribution Management System (DMS), the Outage Management System (OMS) and the Supervisory Control and Data Acquisition (SCADA) system that serve as the foundation of the utility's core system monitoring and operation processes. These upgrades are described in greater detail in the Expenditure Plan section of this document below (Section 8.4.4).

Engineers, designers, and field crews depend on IT systems such as the Geospatial Information System (GIS) and the Distribution Network Analytical Tool to access important asset information across the distribution system, and to develop asset replacement plans, determine project detailed estimates and review the asset conditions prior to physical intervention.

Toronto Hydro's construction project teams and outage response teams rely on IT solutions to execute work plans and respond to outages in a timely and efficient manner. The inventory management system facilitates this function by managing asset inventory levels across multiple warehouse locations, and enabling the delivery of materials at job sites and key locations across the

[12] Tier 2 applications enable divisional and departmental processes. These applications have less complex integration with other enterprise applications than Tier 1, and are typically supported by infrastructure with a lower complexity and lower target for overall availability.

system. A failure of this system could lead to errors in materials information, jeopardize the safety of employees using these materials, delay material delivery to project sites, hamper the utility's ability to respond to outages and execute planned work in a timely and efficient manner.

In addition, Toronto Hydro is proposing to upgrade its suite of Tier 2 IT software applications, which support targeted processes and have fewer integration points with other enterprise applications. Compared to Tier 1 applications, Tier 2 applications generally have lower maintenance costs and support a smaller user base. As such, both the operational risks and corresponding investments associated with Tier 2 software upgrades are lower than Tier 1 applications. Examples of such applications are the data analytics software, power quality application, and the fuel data system. Lifecycles developed in accordance with Toronto Hydro's Strategy are five years or less for these applications. Accordingly, all Tier 2 systems will require one or more upgrades during the 2025-2029 period.

2. Software Enhancements

Over the 2025-2029 period, Toronto Hydro plans to undertake software enhancement projects in alignment with its Strategy. Whereas software upgrades are typically triggered by vendor system support lifecycles, software enhancements are driven by risks or opportunities to improve a particular customer-facing or business process.

Toronto Hydro expects customers' and IT/OT users' demands to continue to change. In order to keep up with the pace of changes in these demands, external facing system enhancements, such as initiatives related to the web portal and customer billing will be required. Data analytics expansions could enable the development of descriptive and predictive data models to assist in areas such as long-term strategy and planning, generation and capacity planning, asset maintenance planning, outage prediction, system planning, and power quality and reliability planning.

Software Enhancements can be implemented using a variety of different IT approaches. Independent systems can be integrated to mitigate the risk of data errors and completeness. Incremental reporting capability can be built to fill gaps in management processes and decision-making. Adding new functionality or new software can expand capability to meet emerging customer needs and preferences.

3. Regulatory Compliance

Each year, Toronto Hydro must make changes to its business processes in order to comply with emerging regulatory requirements and in response to emerging public policy priorities. Toronto Hydro needs to comply with regulatory requirements from a number of agencies, such as Measurement Canada, the OEB, the IESO, the Ontario Securities Commission, and the Ministry of Labour. Failure to meet regulatory compliance obligations exposes Toronto Hydro to financial risk, in the form of penalties, and reputational harm.

Between 2020-2022, Toronto Hydro implemented a number of software changes to respond to evolving regulatory compliance matters, including the OEB customer service rule amendment, Utility Worker Protection Code (UWPC) changes, and COVID-19 Energy Assistance Program (CEAP).

Toronto Hydro anticipates this policy-driven investment to continue in the 2025-2029 period.

E8.4.3.3 Communication Infrastructure

Toronto Hydro has three discrete communication infrastructure needs in the 2025 to 2029 period. Communications infrastructure is relied upon by core utility operations to maintain and operate the distribution system in a safe and reliable manner. The proposed investments address functional obsolescence in Toronto Hydro's current communications infrastructure footprint, address safety and reliability risks, and support the monitoring and control of future smart grid technologies.

Reliability and availability of communication infrastructure play a crucial role in supporting the modernization of business processes to meet changes in customers' needs and preferences in response to the shift towards electrification. If the communication infrastructure used to manage the grid is unreliable, it can lead to longer power outages and operational disruptions, resulting in lower customer satisfaction. In addition, unreliable communication infrastructure will lead to increased worker safety risk and non-compliance with UWPC.

Toronto Hydro plans to undertake the following three communication infrastructure projects in the 2025-2029 period:

1. Cellular SCADA Telecom Infrastructure Upgrade

In the current 2020-2024 period, the communications technology focus had shifted from proprietary SCADA radio technologies to more widely available, resilient and future proof cellular SCADA technologies. As such, cellular SCADA Telecom Infrastructure foundation has been deployed to facilitate the shift towards pole top cellular SCADA endpoints. The current version of the deployed backend cellular SCADA infrastructure will reach the end of its useful life in 2026 and will need to be upgraded to maintain security, functionality and supportability of the environment.

2. Cellular SCADA Endpoint Deployment

The current rate filing period saw the commencement of the migration of pole top SCADA endpoints from proprietary radio systems to standardized cellular technologies. In the 2025-2029 period the migration of the legacy radio system will continue, marking the end of reliance on proprietary and niche vendor radio SCADA technologies, improving the overall reliability of the environment and streamlining maintenance and support.

3. P25 Voice Radio SUA Upgrade Cycle

Motorola P25 Voice Radio system, originally deployed in 2016, provides dedicated, bi-directional voice communication channel between control room staff and field crews, enabling coordination of work efforts and ensuring worker safety. In order to keep the system operational, a series of hardware upgrades and refreshes covered by the System Upgrade Agreement (SUA) must be periodically performed to prevent system obsolescence. The upgrade of the current cycle is scheduled for 2025 and will extend the system's useful life until 2028. Another upgrade in 2029 will be required to keep the system operational until 2031.

E8.4.4 Expenditure Plan

Table 4: Historical & Forecast Program Costs ($ Millions)

Segments	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
IT Hardware	11.6	15.1	14.9	15.9	15.0	17.5	19.8	22.6	18.1	20.3
IT Software	22.2	26.6	42.4	42.3	38.7	38.6	40.6	41.0	33.3	34.8
Communication	3.6	2.4	0.7	1.8	1.7	3.7	2.5	0.9	6.8	1.0

Segments	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Infrastructure										
Total	**37.4**	**44.7**	**58.0**	**60.6**	**56.0**	**59.7**	**62.9**	**64.5**	**58.2**	**56.0**

Over the 2025-2029 period, Toronto Hydro forecasts spending $301.3 million across the three IT/OT Program segments. This represents an increase of $46.5 million (or approximately 18.2 percent) compared to the 2020-2024 planned spend under the IT Hardware, IT Software and Communication Infrastructure segments.

IT/OT systems perform vital functions that are central to the safe and reliable operation of the distribution system and to the effective interaction between the utility and its customers. The proposed spending is required to (i) refresh IT hardware systems at the end of their useful life (ii) upgrade Toronto Hydro's IT software applications to ensure system is current, and make targeted investments to provide software enhancements that address business risks, process improvement opportunities or compliance matters; (iii) address specific OT system needs to mitigate risks such as functional obsolescence; and (iv) maintain a strong cybersecurity posture to mitigate against potential vulnerabilities and threats that may jeopardize the safe and proper functioning of IT/OT assets.

As detailed in Exhibit 2B, Section D8, Toronto Hydro has a robust decision-making process to govern its IT/OT program. In accordance with this Strategy, the utility ranks and prioritizes initiatives in this program by weighing and balancing the following considerations and their impact on the utility's operations and customers:

- Compliance with applicable regulatory requirements;
- Alignment with the organization's strategic objectives including Grid Modernization, Energy Storage, Process Automation, Customer Experience, and Customer Engagement;
- Required availability of the IT/OT systems to support core business operations and planned work programs. As described above, enterprise software applications are categorized into two tiers based on their criticality. Upgrades to Tier 1 applications take priority over Tier 2;
- Ensuring data in the IT/OT systems are secure and protected from cyber-attacks;
- Sustaining and improving current levels of customer service; and

- Other considerations such as application complexity, resource balancing, and inter-dependencies with other programs.

A number of controls and practices are in place to ensure that IT investments deliver value to customers either directly, through improved customer service, or indirectly from performance or cost improvements. IT/OT expenditures are subject to Toronto Hydro's procurement policy, which can be found in Exhibit 4, Tab 3, Schedule 1, Appendix A. For IT software investments, this applies to both the application itself and the system integration support services that are required to implement the solution efficiently and cost-effectively. Toronto Hydro leverages existing vendors of record lists at the municipal or provincial level to secure potential volume discounts to obtain IT products at lower price points.

An independent benchmarking study performed by Gartner Consulting (Gartner) concluded that Toronto Hydro's IT expenditures as of 2022 benchmark competitively against industry peers.[13] Gartner also concluded that the distribution of Toronto Hydro's IT investments by cost category, investment category, and functional area are all comparable to the peer group, with 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 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).[14]

Gartner further assessed Toronto Hydro's spending in a Run-Grow-Transform paradigm, defined as:

- **Run**: "essential (and generally non-differentiated) business processes."
- **Grow**: "improvements in operations and performance, within current business models."
- **Transform**: "new services and new operating models."

In both 2017 and 2022, Toronto Hydro IT investments were primarily directed at maintaining current business capabilities ("run") with the remainder directed at expanding existing business capabilities or driving new ones ("grow" and "transform" respectively).[15] The resulting split among the three categories is comparable to the peer group average. The increase in Toronto Hydro's 2022 IT

[13] Gartner Consulting (2023), *IT Budget Assessment Final Report* found in Exhibit 2B, Section D8, Appendix A
[14] *Ibid* at page 5.
[15] *Ibid*.

spending compared to 2017 is similar to industry peers. Toronto Hydro interprets this result as confirmation that its IT expenditures are appropriately balanced.

E8.4.4.1 IT Hardware

1. IT Infrastructure

The table below outlines the approximate volume of hardware assets for the 2020-2024 period and the 2025-2029 period. Projected cost increases are a function of higher cost-per-unit, due to hardware prices increases and higher Capacity/Unit Count which can be attributed to several factors including optimizing system performance, supporting the implementation of new IT transformation initiatives and increases in workforce. This will result in more processing power, larger storage capacity and higher network performance. Core Infrastructure units are presented in terms of Windows, Linux and UNIX virtual servers with individual unit costs reflecting the burdened cost of the entire underlying Core Infrastructure, including power, telecom, network, storage, backup, server and virtualization infrastructure layers.

Table 5: Hardware Volumes

Asset Category	IT Hardware	2020-2024 Actuals/Bridge		2025-2029 Plan	
		Capacity /Units	Total Cost ($M)	Capacity /Units	Total Cost ($M)
Core Backend Infrastructure Assets (Capacity)	*Unix Virtual Servers*	560	47.9	650	64.3
	Linux x86 Virtual Servers	349		400	
	Windows Virtual Servers	2656		3100	
Endpoint Assets (Units)	*Personal Computing Devices*	2308	11.9	2500	13.6
	Printers & Plotters	180		130	

IT hardware cost estimates are derived by forecasting the number of hardware assets that are past their useful life and that are needed for incremental needs over the 2025-2029 period. Table 5 illustrates that the Hardware program covers the replacement of existing units of infrastructure and the expansion of numbers of units to support enhancement and transformation initiatives, with the exception of printers and plotters which decreased by 28 percent.

The Strategy details the utility's approach to replacing IT hardware assets. The timing and pacing of investment in each asset sub-type is driven by the asset lifecycle. This is defined by the applicable standard, which is based on factors such as the criticality of the infrastructure, industry best practice, and vendor specifications. These standards are designed to extract the maximum value from hardware assets and minimize the negative impact of potential asset failures.

Toronto Hydro also considers forecast capacity requirements to ensure it has the necessary IT hardware to support general business growth and associated increased data storage and data processing requirements. The forecasts are based on the analysis of the following factors:

- Historical trends of current assets capacity versus utilization by existing IT systems;
- Asset resource requirements to support system enhancements and new initiatives; and
- New operational requirements that necessitate increased hardware resources.

Based on this approach, Toronto Hydro will require $77.9 million to replace and expand the number of IT hardware assets. Of Toronto Hydro's current assets, approximately 90 percent of existing core backend infrastructure (e.g. network, storage, and server assets) are forecast to require replacement in order to address obsolescence, security and reliability risks associated with aging assets and provide the incremental capacity needed to support Toronto Hydro's IT footprint. The utility anticipates that all endpoint assets will need to be replaced between 2025 and 2029, at a pace that will address an approximately equal number of assets each year.

The investments proposed above will provide for secure and reliable IT infrastructure, supporting all operational activities, business processes, IT/OT systems and applications of Toronto Hydro. They will enable alignment with IT Assets Lifecycle & Capacity specifications outlined in the Toronto Hydro IT architecture standards by replacing all hardware assets before the end of useful life, ensuring adequate capacity and continued vendor support. Adhering to effective asset management practices will also ensure that adequate cybersecurity posture is maintained through timely system upgrades and new technology deployments.

2. IT Cybersecurity Practice

The table below outlines the approximate volume of cyber-security controls for the 2020 – 2024 period and the 2025 – 2029 period. Projected cost increase is primarily a function of growing IT footprint and higher unit costs arising from the need for more complex cybersecurity technologies to maintain adequate cybersecurity posture in response to expected increases in emerging threats, as well as vendor price increases across the board.

Table 6: Cybersecurity Systems and Controls

IT Cybersecurity Practice	2020-2024 Actuals/Bridge		2025-2029 Plan	
	Capacity /Units	Total Cost ($M)	Capacity /Units	Total Cost ($M)
OEB CSF Controls & Compliance	545	12.7	600	20.2
Asset Security: Systems/Applications	1,600		1,800	
Asset Security: Endpoints	30,265		33,000	

Cybersecurity systems and controls are grouped into three distinct categories, namely the OEB Cyber Security Framework (CSF) Controls & Compliance, Asset Security Systems and Applications and Asset Security for Endpoints. These categories are inclusive of the entirety of Cybersecurity technology landscape, such as Firewalls, Intrusion Detection System (IDS), Intrusion Prevention System (IPS), Endpoint Detection and Response (EDR), Data Loss Prevention (DLP), Virtual Private Network (VPN), vulnerability management, anti-malware, anti-phishing, logging, alerting and other related systems. Costs associated with these technologies have been allocated on a per-unit basis to the ecosystem of IT systems, applications, endpoints and associated data being protected.

The investments proposed above will enable Toronto Hydro to not only maintain its cybersecurity posture at the current levels, but also develop future state readiness to adapt to the constantly changing cybersecurity threat landscape. This will be achieved through investment in advanced cybersecurity technologies, such as honeypots, attack surface management and micro-segmentation, aimed at proactively detecting and containing inherently unknown threats, such as zero-day attacks, in addition to defending against known threats.[16]

E8.4.4.2 IT Software

The table below outlines the spend for the 2020-2024 and 2025-2029 rate periods:

[16] *Supra* notes 5-8.

Table 7: IT Software Costs ($ Millions)

IT Systems	2020 - 2024 Actual & Bridge	2025 - 2029 Plan
Total Cost	172.1	188.3

1. Software Upgrades

Over the 2025-2029 period, Toronto Hydro plans to spend $188.3 million on IT software upgrades, enhancements and regulatory compliance initiatives.

As discussed in the driver's section, Toronto Hydro plans to upgrade its Tier 1 software applications. Table 8 below outlines the historical and forecast spending for the Tier 1 software applications.

Table 8: Tier 1 IT Systems Upgrades Costs ($ Millions)

IT Systems	2020 – 2024 Actual & Bridge	2025 - 2029 Plan
ERP	24.4	28
CIS	38	N/A
ADMS	N/A	34.2
Tier 1 Systems excluding ERP, CIS	41.6	46
Tier 1 Systems Total	104	108.2

a. <u>Upgrade to SAP Enterprise Resource Planning (ERP) System</u>

An ERP system is critical for Toronto Hydro, as it integrates various financial, procurement, human resource, and asset management business processes into a single system. [17] For instance, the ERP system can support managing inventory of equipment and supplies, scheduling maintenance and repairs, managing vendors and inbound logistics, and managing workforce. By providing a centralized and unified view of the company's operations, an ERP system helps improve decision-making capabilities, identify areas for cost savings, and optimize operations for maximum efficiency. Additionally, the ERP system enables compliance with regulatory requirements by providing tools for tracking and reporting on the company's activities.

[17] Exhibit 2B, Section E8.4, Appendix B.

Based on the Strategy, Toronto Hydro is proposing to upgrade its ERP system to the next version (i.e. S4 HANA) in the 2025-2029 period. The initiative will deliver a modern ERP system that is fully vendor supported and that effectively and efficiently executes business processes. The ERP system would strengthen Toronto Hydro's cybersecurity posture, modernize Toronto Hydro's business processes in response to changes in customers' needs and expectations due to shift towards electrification.

b. Advanced Distribution Management System (ADMS)

Toronto Hydro is looking to upgrade its current Advanced Distribution Management Systems (ADMS) which is a software platform consisting of a suite of several software applications to assist Control Centre operators in monitoring and controlling the distribution system.[18] Currently, Toronto Hydro operates separate instances of SCADA and Network Management System (NMS). Core operational systems are supported by a number of purpose-specific auxiliary applications, such as Automated Call-Out and voice radio communications with field crews.

Since the integration between these systems is unidirectional from SCADA to NMS, manual processes are required to keep the systems synchronized. This results in disparate user interfaces, data duplication and risk from human error.

By upgrading the existing ADMS, Toronto Hydro can achieve operational and safety excellence, enable advanced predictive and automation capabilities, implement a self-healing grid for automated outage restoration, provide automated and smart dispatching, offer holistic situational awareness, optimize distribution grid performance and customer experience, and gain full DERMS capabilities. ADMS can help Toronto Hydro manage the response to outages, meet growing customer and regulator expectations, and address the complexity introduced by the expected increase in penetration of distributed energy resources (DERs) in the electric distribution system. ADMS software analyzes data from field devices, alerts operators to adverse electrical conditions and inefficiencies, and offers advice to address these issues or performs recommended control actions automatically. These new advanced capabilities will equip Toronto Hydro with the tools required to respond effectively to future challenges associated with electrification by providing its customers with a timely and efficient outage response.

[18] Exhibit 2B, Section E8.4, Appendix A.

c. Other Tier 1 Systems

During the 2025-2029 period, Toronto Hydro plans to upgrade its other Tier 1 applications (listed in Section 8.4.3.2) in line with lifecycles developed and pursuant to its Strategy. Cost variances for these upgrades, as shown in Table 8, are primarily due to inflation.

d. Tier 2 Systems

Table 9: Planned Tier 2 Application Upgrades

	2020-2024 Actuals/Bridge		2025-2029 Plan	
	Number of Applications	Cost ($M)	Number of Applications	Cost ($M)
Tier 2 Systems	72	12.4	80	14

The forecasts in the table above were derived by analyzing the lifecycles of all Tier 2 applications. Applications must be upgraded before reaching the end of their useful lives to mitigate the risk of failure and disruption to the business processes they support. Increasingly, vendors are reducing the lifecycles of Tier 2 applications (i.e. less than 4 to 5 years), meaning an increasing number of applications will require more than one upgrade over the 2025-2029 period. The primary drivers of the variance between 2020-2024 and 2025-2029 rate periods include the increased cost of upgrading on shorter intervals, additional Tier 2 Systems and general price inflation.

2. Software Enhancements

Software enhancements mitigate core business risks that would not be technically feasible or cost-effective to address through a non-IT solution or manual business processes. The table below presents the number of forecasted software enhancements initiatives and their associated costs in the 2020-2024 period and 2025-2029 period.

Table 10: Software Enhancements Volumes and Cost

	2020-2024 Actuals/Bridge		2025-2029 Plan	
	Number of Enhancements	Cost ($M)	Number of Enhancements	Cost ($M)
Software Enhancements	42	45.1	55	54.6

As discussed in the Drivers section, software enhancements can take a number of different forms: adding new functionality to an existing application (aside from ERP and ADMS, which are discussed above), integrating two systems to leverage otherwise independent data sets, expanding of reporting capabilities to make better use of existing data, or adding a new application.

The increase in cost for Software Enhancements between 2020-2024 and 2025-2029 is a result of multiple factors. Toronto Hydro expects that customer and operationally-driven enhancements will be necessary to address business continuity and operational risks, respond to changing consumer preferences and shift towards electrification. Inflation also contributes to the increase in Toronto Hydro's proposed planned expenditures.

A reduction in funding for software enhancements may lead to Toronto Hydro's inability to keep pace with technology changes in the industry, and less capability to respond to emerging customers' needs and business-driven risks. The $54.6 million in software enhancements planned for the 2025-2029 plan period accounts for approximately 29 percent of Toronto Hydro's IT software segment. Toronto Hydro's total IT expenditures, of which Software Enhancements is one component, are generally consistent with its peer group in terms of the Run-Grow-Transform paradigm articulated in the Gartner IT benchmarking study (See Exhibit 2B, Section E8.4, Appendix C).

3. Regulatory Compliance

The table below presents the anticipated number of regulatory compliance initiatives Toronto Hydro will be required to complete in the 2025-2029 period and the associated budget.

Table 11: Regulatory Compliance Volumes and Cost

	2020-2024 Actuals/Bridge		2025-2029 Planned	
	Number of Initiatives	Cost ($M)	Anticipated Number of Initiatives	Cost ($M)
Regulatory Compliance	5	10.6	6	11.5

Toronto Hydro anticipates it will require incremental funding for new compliance-related initiatives in the 2025-2029 rate period, attributable to forecasting a similar volume of public policy initiatives driving new compliance requirements as occurred during the 2020-2024 period.

E8.4.4.3 Communication Infrastructure

Communications infrastructure is relied upon by the utility's core operations to maintain and operate the distribution system in a safe and reliable manner. The proposed investments address functional obsolescence in Toronto Hydro's current communications infrastructure footprint, address safety and reliability risks, and support the monitoring and control of future smart grid technologies.

The table below outlines the actual and forecasted volume of communication infrastructure assets for the 2020-2024 and the 2025-2029 rate periods. It is important to note as the program scope for the 2025-29 period is different than 2020-2024, the new projects are shown as separate rows at the bottom of the table below.

Table 12: Communication Infrastructure Volumes and Cost

Asset Category	Communication Hardware	2020 – 2024 Actuals / Bridge		2025 – 2029 Plan	
		Capacity / Units	Total Cost ($M)	Capacity / Units	Total Cost ($M)
Communication Infrastructure	*SONET Migration and Decommissioning*	31	3.1	0	0
	Fibre-Optic Cable	15	1.8	0	0
	SCADA High-Site Capacity Upgrade	12	0.9	0	0
	Wireless SCADA Endpoint Radio Migration	1,103	3.0	0	0
	Radio Installation	0	0	0	0
	Underground Radio Sites	0	0	0	0
	Cellular Telecom Infrastructure (initial deployment)	2	1.4	0	0
	Cellular SCADA Telecom Infrastructure Upgrade	0	0	2	1.5
	Cellular SCADA Endpoint Deployment	0	0	1,250	4.2
	P25 Voice Radio SUA Upgrade Cycle	0	0	1	9.1
	Total		**10.2**		**14.8**

As detailed in Section E8.4.3.3, over the 2025-2029 period Toronto Hydro plans to undertake work in three discrete projects in this segment:

1. Cellular SCADA Telecom Infrastructure Upgrade

Toronto Hydro expects to spend approximately $1.5 million in 2026 for this upgrade and system capacity expansion at its two data centers, facilitating future growth as the number of Cellular SCADA endpoints extends to other use cases beyond pole top RTUs, such as underground vaults and pad-mount transformers.

2. Cellular SCADA Endpoint Deployment

Toronto Hydro expects that the migration of pole top SCADA endpoints from proprietary radio systems to Cellular SCADA will be conducted in the 2025-2029 rate filing period. Toronto Hydro expects that approximately 1250 endpoints will be migrated to Cellular SCADA in the 2025-2029 period at a total cost of $4.2 million. This work will be paced uniformly from year to year over the 2025-2029 period, considering the available resource capacity to perform the migrations.

3. P25 Voice Radio SUA Upgrade Cycle

Toronto Hydro expects to perform an upgrade of the Motorola P25 Voice Radio System in 2025 at a cost of approximately $2.6 million. This is the last system upgrade, in the cycle of upgrades, under the current System Upgrade Agreement (SUA), extending the system's useful life until 2028. Toronto Hydro expects to sign a new SUA in 2028 that will keep the system operational for future years, extending its useful life and avoiding premature costly replacements. Based on provided vendor estimates the new SUA is expected to require $6.5 million of Capital expenditures between 2028-2029.

E8.4.5 Options Analysis/Business Case Evaluation (BCE)

E8.4.5.1 Options Analysis/BCE for IT Hardware Segment

1. IT Infrastructure

a. <u>Option 1: Managed Deterioration</u>

Choosing this option will result in a reduction of investment in the IT Hardware Infrastructure program and in IT capacity upgrades. As a consequence, IT equipment will be operated beyond its useful life and the hardware will no longer be supported by vendors. This situation can cause a significant increase in operational costs due to higher-priced extended support and insufficient IT capacity to meet key business processes. This option poses several major risks, including frequent IT service outages, reduced and eroded availability of mission-critical IT systems, and insufficient capacity to support growing data volumes and processing requirements. Additionally, using obsolete equipment may result in increased exposure to cybersecurity attacks, data loss, service unavailability, and impact to brand reputation. There is a high likelihood that this will result in software compatibility issues and jeopardize any changes, improvements and upgrades to IT Software. Unsupported hardware failures may result in data losses and the inability to recover lost data, posing an unacceptable risk to the utility's ability to provide core services to ratepayers and comply with legislative and regulatory obligations.

Furthermore, adopting this option for the rate filing period will create much greater capital and operational spend requirements in the next filing period. Toronto Hydro will need to catch up on the insufficient spend and perform major version and architectural upgrades as opposed to gradual incremental ones. This option is not advisable as it can negatively impact Toronto Hydro's ability to adequately support existing business needs, service customers and result in increased operational costs.

b. Option 2: Sustainment (Preferred Option)

Under this option Toronto Hydro will manage the IT Infrastructure program as per approved hardware standards. Opting for the sustainment option will enable Toronto Hydro to ensure consistent and reliable IT infrastructure with minimal service disruptions. By selecting this option, IT infrastructure can remain upgraded, ensuring that all assets are sized to adequate capacity with appropriate vendor support. This means that IT teams can focus on maintaining and enhancing existing systems, rather than constantly troubleshooting outdated equipment and software.

Furthermore, choosing the sustainment option enables the organization to maintain an adequate security posture by ensuring that system upgrades and new technology deployments are implemented in a timely fashion. This approach minimizes the risk of security breaches and protects confidentiality of customers’ and employees’ personal data from potential threats.

By aligning Toronto Hydro IT hardware programs with standards, it secures a nominal spend request for the next filing period. The sustainment option optimizes IT spend, avoids significant spikes in capital/operational spend and reduces overall costs. The sustainment option provides a stable and secure IT environment that allows the organization to focus on its core business activities and customer services, without increasing risks to the reliability and availability of the underlying IT infrastructure.

c. Option 3: Improvement

Under this option Toronto Hydro could provision extra capacity and enable early lifecycle replacement. Opting for the Improvement option may seem like a preferable choice to enhance IT infrastructure, but it will result in suboptimal utilization of available IT hardware resources and increased support costs. This approach does not yield any tangible benefits over the optimal selection of technologies covered in the Sustainment option. There is a high likelihood that with overprovisioned infrastructure a large number of resources are idle resulting in inefficient investment.

This approach will lead to increased operational cost burden through a larger technology footprint. Furthermore, exercising this option may lead to increased operational cost burden in the next filling period due to a larger IT hardware asset footprint.

d. Options Evaluation

The Sustainment option is the preferred option because it achieves an optimal balance that allows Toronto Hydro to maintain its IT infrastructure at an adequate level while optimizing the utility's overall IT spend. In comparison to the Managed Deterioration option, the Sustainment option provides a stable and secure IT environment that minimizes the risk of security breaches and ensures that IT teams can focus on enhancing existing systems. In comparison to the Managed Deterioration and Improvement options, this option will allow Toronto Hydro to avoid significant spikes in capital and operational spending.

In comparison to the Improvement option, the Sustainment option decrease likelihood of large number of resources being idle. By aligning with approved hardware standards, Toronto Hydro can ensure that all hardware assets are sized to adequate capacity with appropriate vendor support. This approach minimizes the sunk costs from unutilized or underutilized hardware resources. The Sustainment option secures the same security posture as the improvement option and protects confidentiality of customers' and employees' data from potential threats.

Overall, the Sustainment option provides a balance between minimizing business continuity and operational risk, optimizing IT spend, and maintaining adequate IT infrastructure.

2. IT Cybersecurity Practice

Cybersecurity practice investment options are presented in the form of Managed Deterioration, Sustainment and Improvement, with Improvement being the preferred option. Each option covers the entirety of the IT domain in terms of the number of OEB Cyber Security Framework (CSF) controls, systems and applications and endpoints that are in scope, but differ in the amount of investment into the latter two categories.

a. Option 1: Managed Deterioration

Managed deterioration option includes limited investment into the overall Cybersecurity posture, and primarily focuses on maintaining the existing controls, which may lead to the inability to maintain compliance with OEB CSF in the future. In addition, this option will effectively prevent any innovation in the Cybersecurity space resulting in gradually deteriorating security posture unable to cope with evolving cybersecurity threats.

This option carries the largest amount of risks to the environment, as suboptimal cybersecurity controls arising from inadequate investment will inevitably leave the organization vulnerable to cybersecurity threats, potentially compromising critical OT systems and sensitive customer and employee information. This will negatively impact Toronto Hydro’s ability to avoid business disruptions and ensure security and confidentiality of sensitive information. Opting for Managed Deterioration will also translate into operational spend increases due to the need to secure extended support for obsolete systems and increase future investment requirements. Due to the increased risk of cybersecurity exposure, this option is the least preferred way forward.

b. Option 2: Sustainment

Sustainment option encompasses continued investment into the Cybersecurity practice with the goal of ensuring all existing controls are managed and expanded to keep up with the evolving threats, with the intent of maintaining Cybersecurity posture at the same level as the previous filing. Investment at the sustainment level will ensure that all existing controls will continue to be adequately maintained and new functionality would be organically integrated into the threat protection ecosystem.

Sustainment option aims to maintain the level of risk consistent with the previous filing, ensuring that all systems, applications and endpoints remain adequately protected against the constantly changing threat landscape. However, this option will not reduce the risk to the organization from its current baseline, as transformative initiatives exploring cutting edge protection mechanisms would not be implemented. Due to the inherent uncertainty of the future threat landscape, maintaining cybersecurity posture at historical levels may not be sufficient to ensure adequate protection going forward. As such, Sustainment, while preferable to Managed Deterioration, remains a suboptimal option compared to the Improvement alternative.

c. Option 3: Improvement

Improvement option encompasses the increased investment into the Cybersecurity practice to enable the expansion of existing Cybersecurity threat management and response capabilities, resulting in a stronger security posture. In addition to ensuring that all existing cybersecurity controls are maintained at adequate levels, Improvement option will add new cybersecurity technologies to ensure that Toronto Hydro is capable of adapting to the continuously evolving threat landscape while reducing its risk exposure.

Improvement option aims to reduce the cybersecurity risk by implementing additional controls across IT/OT systems, applications and endpoints to ensure better ability to prevent, detect and contain threats compared to the current state. This will have the net effect of improving cybersecurity posture, resulting in better protection of Toronto Hydro’s IT/OT assets and confidentiality of customers’ and employees’ personal information while further reducing the chance of cybersecurity-related incidents and business disruptions. Therefore, Improvement option is positioned as the preferred investment option.

d. Options Evaluation

Improvement is positioned as the most optimal spend for the IT Cybersecurity practice area. Increased investment into this area will enable Toronto Hydro to handle the evolving threats of tomorrow in addition to maintaining its current cybersecurity posture and preventing technological obsolescence, ultimately reducing overall risk for the organization.

Managed Deterioration and Sustainment options are considered inferior, due to the inherent compliance, privacy and cyber security corporate risks associated with the inability to strengthen cybersecurity posture in response to the everchanging cybersecurity threat landscape. Managed deterioration in particular carries the implication of weakening cybersecurity posture and increased operational expenditures to maintain end-of-support ecosystem. Opting for either of these options would increase Toronto Hydro's liability risk at the corporate level due to elevated cybersecurity risk levels.

Failing to grow and expand the security controls protecting Toronto Hydro systems, applications and endpoints carries a high risk of negatively impacting Toronto Hydro business continuity, customer information protection, reputation and revenue generation. Toronto Hydro is governed by OEB recommended privacy and security controls, government regulations and data protection requirements. The incremental planned expenditure presented in the Improvement option aims to reduce the occurrence of future cybersecurity related incidents or business disruptions in addition to protecting its IT/OT assets, safeguarding employees' and customers' personal information, meet security compliance obligations, provide assurance to our industry partners, customers and stakeholders, and facilitate the shift towards electrification.

E8.4.5.2 Options Analysis/BCE for IT Software

1. Option 1: Managed Deterioration

The Managed Deterioration option involves reducing investment in IT software capital expenditure, specifically in the categories of Tier 1 upgrades, Tier 2 upgrades and software enhancements, with the exception of the ERP Upgrade and ADMS upgrade. This option implies that Toronto Hydro would not upgrade all its Tier 1 and Tier 2 applications according to the Strategy, increasing the risks to system reliability and availability. Toronto Hydro would need to maintain and customize these applications using manual work-arounds, which could become increasingly complex, inefficient, and costly over time. The lack of vendor support for security-related patches poses significant cyber security risks, as outdated systems would be more vulnerable to cyber-attacks and compromises. This could result in data loss, IT service interruptions, and negative impact on brand reputation.

IT software systems are essential to many critical business procedures and processes, such as the Toronto Hydro's public policy processes, safety procedures, and financial reporting. A reduction in capital spend would negatively impact all of these processes, and limit Toronto Hydro's ability to support key divisional and corporate metrics such as reliability, safety, customer service and financial indicators. Potential risks include frequent IT service outages and reduced availability of critical IT systems.

Limiting software enhancements would negatively affect business units' ability to meet their goals and objectives, potentially affecting grid operations and ability to restore power. Toronto Hydro would be unable to invest in advanced digital platforms to improve customer experience or enhance technologies to provide timely and accurate communication with customers during outages.

Moreover, there would be a significant increase in operational costs to support legacy and out-of-support systems, which would impede the organization's ability to implement systems that support future changes in business process requirements and growth.

2. Option 2: Sustainment

The Sustainment option focuses on minimizing risks to the reliability and cybersecurity of Toronto Hydro's IT software applications. In this option, all IT systems will be actively managed and timely upgraded. This would ensure Toronto Hydro has vendor support and it would eliminate risks to business continuity from system downtime and minimize cyber security risks. It would address compatibility risks that could arise from integrating systems that are not current.

This option will allow Toronto Hydro to meet its commitments with regulatory compliance and achieve the upgrades of the ERP System and ADMS System.

However, Toronto Hydro would curtail the spend in Software Enhancements to meet the spend objectives. This will limit Toronto Hydro’s ability to modernize its IT business processes and address customers’ changing needs and preferences in response to industry shift towards electrification. Limited funding in software enhancements would also leave Toronto Hydro unable to keep pace with technology changes in the industry.

3. Option 3: Improvement

The Improvement option balances spend across upgrades, regulatory compliance and enhancement initiatives. Similar to Sustainment option, all IT systems will be actively managed and timely upgraded. Toronto Hydro will meet its commitments with regulatory compliance and achieve the upgrades of the ERP System and ADMS System.

Additionally, this option will provide an optimal level of investment in software enhancements, which would allow Toronto Hydro to stay on par with its peer group.

This option will support the modernization of IT business processes in alignment with Toronto Hydro's growth and modernization strategic objectives and meet customers' changing needs and preferences in response to electrification.

4. Options Evaluation

The Improvement option is the preferred option. The Improvement option is optimal because it focuses on minimizing risks to the reliability and cybersecurity of Toronto Hydro's IT software applications while enabling the company to sustain its IT/OT systems and modernize its IT business processes.

Similar to Sustainment option, the Improvement option proposes all software upgrades to ensure that Toronto Hydro's software systems receive vendor support, remain integrated with other relevant software systems, are protected against cybersecurity threats.

In contrast, the Managed Deterioration option involves reducing investment in IT software capital expenditure, specifically in software upgrades and enhancements, which would leave some Toronto Hydro's IT systems without vendor support and vulnerable to cyber-attacks and compromise security. This option would negatively impact critical business procedures and processes, increase operational costs to support legacy systems, and hinder Toronto's Hydro's ability to deliver on performance outcomes such as System Reliability and Resilience.[19]

The Sustainment option proposes to sustain the status quo level of investment. However, the Sustainment option limits Toronto Hydro's ability to invest in IT enhancements, innovation and the modernization of IT business processes. In contrast, the Improvement option would allow Toronto Hydro to stay on par with its peer group and effectively respond to changing customers' needs due to shift towards electrification and future business transformation.

E8.4.5.3 Options/BCE for Communication Infrastructure

1. Option 1: Managed Deterioration

The Managed Deterioration option for communication infrastructure involves reducing investment in Communication Hardware Assets where a fewer number of wireless SCADA endpoints are

[19] Exhibit 1B, Tab 2, Schedule 1.

migrated from private radio to cellular communications. In turn, it increases operational risks and extends the time needed to complete the program. Critical SCADA communications equipment is run past the end of its useful life, resulting in obsolete hardware that is no longer supported by vendors. This can lead to higher operational and business continuity risks due to system obsolescence resulting in frequent outages, significantly increased operational costs, inability to replace faulty equipment in a timely fashion due to supply chain issues, and a lack of availability of qualified personnel to perform skilled work. Adopting this option will likely result in greater capital investment and operational spend for the period beyond 2029 to catch up on delinquent installations and upgrades, and maintain obsolete equipment past its useful life. In addition, a higher level of capital investment will be required to complete upgrades beyond 2029 due to anticipated increases in costs (e.g. inflation). This option also does not align with the organization's strategic objectives of growth and modernization as communication hardware assets will not be able to respond to changes in customers' needs and preferences associated with future industry challenges such as electrification. Limited investments in communication hardware assets will render them without vendor support, resulting in inability to perform the necessary upgrades or access patches to respond to future industry challenges.

2. Option 2: Sustainment

The Sustainment option ensures that communication infrastructure is replaced as per the Information Technology Asset Management Strategy and Investment Planning procedure, and all communications equipment remains supported by vendors. This option ensures an available and reliable communication infrastructure with little to no service disruption, resulting in minimal operational risk. In addition, the adoption of efficient and secure communications with cellular SCADA endpoints significantly reduces cybersecurity risk by ensuring an adequate security posture through timely upgrades and new technology deployments. It avoids significant increases in capital investment and operational spend, which is beneficial in the long run. The sustainment option ensures that an adequate security posture is maintained, and the risk of obsolescence is mitigated.

This option optimally aligns with the organization's strategic objectives of growth and modernization by ensuring the availability of reliable and secure communication infrastructure to sustain day-to-day operations and ability to adapt to changes in customers' needs and preferences in response to future industry challenges such as electrification.

3. Option 3: Improvement

The Improvement option for communication infrastructure involves accelerating the deployment of wireless SCADA endpoints. The utility would need to onboard additional resources on a one-time basis to fulfill this requirement. This option can help Toronto Hydro take advantage of the benefits of faster adoption of cellular communications technology for wireless SCADA endpoints. This option will require the availability of necessary specialized resources, including personnel and equipment, to meet the increased workload. As a result, there is a significant operational risk associated with securing these resources as they are not easily and readily available to Toronto Hydro and will require greater capital investment. Despite the risks, this option offers several benefits, including faster adoption of cellular technology, which can improve the efficiency and reliability of Toronto Hydro's communication services. By accelerating the deployment of wireless SCADA endpoints, Toronto Hydro can take a proactive approach to improving its communication infrastructure and enhancing the overall customer experience.

4. Options Evaluation

The Sustainment option is recommended. In comparison to the Managed Deterioration option, the Sustainment option offers a more proactive and long-term approach to ensure the reliability, availability and security of Toronto Hydro’s communication infrastructure. The Sustainment option also ensures communication infrastructure assets are upgraded as per Information Technology Asset Management Strategy and Investment Planning procedure and remain supported by vendors. This option ensures alignment with modernization by enabling system growth and preventing the risk of obsolescence, service disruption, and cyber-security threats. The Managed Deterioration option involves limited investments and extending the time needed to complete the upgrade, which can result in increased operational risks and frequent outages.

The Improvement option for communication infrastructure offers benefits such as faster adoption of cellular technology and improved efficiency and reliability of communication services. However, it poses high operational risks due to significant uncertainty in ensuring the availability of personnel and equipment resources to complete the extra work and greater capital investment.

The Sustainment option offers an optimal balance between investment required and operational risk management, ensuring that Toronto Hydro's communication infrastructure remains secure, reliable, and adequately supports future business requirements. Therefore, the Sustainment option is the preferred option.

E8.4.6 Execution Risks & Mitigation

This section discusses various potential risks to the execution of the IT/OT program, and Toronto Hydro's corresponding mitigation measures:

- **Cybersecurity Threats:** Even with a strong cybersecurity posture, it is possible for cyber threats to impact a company's ability to execute the IT/OT program on time and within budget. To mitigate these risks and minimize the associated impacts, Toronto Hydro developed incident response and business continuity plans to address potential disruptions caused by cyber threats. Mitigation strategies include employing backup systems, implementing redundant infrastructure, and sourcing alternative suppliers or vendors.
- **Regulatory Requirements:** Implementation of new regulatory requirements may require more resources and time than budgeted. If new regulatory requirements emerge at a higher than expected rate, resources will be re-allocated accordingly to ensure that Toronto Hydro complies with application requirements. Projects will be rescheduled as necessary in accordance with the project prioritization considerations outlined in section E8.4.4.2 above.
- **Software Release Dates:** Changes to application version release dates will impact the project schedule and potentially impact downstream projects in the program. If one or more software upgrades require another software upgrade to be completed first, any delay in the release of the first software upgrade will delay the upgrade of the dependent software system(s). To address this risk Toronto Hydro monitors release dates, ensures that all impacted projects are properly sequenced and maintains a holistic view of IT environment/architecture to identify interdependencies.
- **Technology Change:** New technology may be introduced after previous assets were refreshed during the asset's lifecycle. This risk may impact project cost, as new technology may need to be procured to meet business requirements. Toronto Hydro closely monitors the latest trends to determine how technology fits into existing Toronto Hydro IT standards and business requirements. In addition, Toronto Hydro assesses and evaluates future IT

investments to ensure preparedness to respond to future challenges such as electrification and align with the organization strategic objectives.

- **Solution Fit to Utility Requirements**: A design approach that considers functionality in isolation is particularly risky. The solutions proposed for incorporation into the upgraded and expanded IT systems must be able to deliver the functionality Toronto Hydro requires to meet its operational, regulatory, and customer obligations. Toronto Hydro will fully consider all areas of its operations before any configuration or coding has taken place. All processes and system requirements will be defined and documented by Toronto Hydro prior to tools, components and modules selection, and integration. End-to-end operational process scenarios will be used in the testing phase of the system.
- **IT/OT Systems Integration:** Different systems may not properly integrate with each other when a system or group of systems are upgraded or replaced. If the current level of integration is not maintained, business processes could be impeded and process inefficiencies could be introduced from manual data updates. Toronto Hydro considers and analyzes new component configurations in defining project scopes, and conducts thorough due diligence during technical feasibility studies.
- **Internal Resource Availability:** There may be insufficient resources to complete the planned program tasks and activities, which could delay interdependent and downstream work activities and lead to escalations in project costs due to the need to procure temporary skilled resources at a premium. In response, Toronto Hydro will: (i) adopt a long-term resource plan based on required skills to support project tasks and activities that the utility plans to undertake over the 2025-2029 period; (ii) train and cross train resources to ensure employee engagement, employee retention and workforce sustainability; and (iii) ensure appropriate responsibility overlaps between labour resources to minimize impact from attrition.
- **Vendor Management:** Vendors may not meet program delivery obligations or may change the product cost structure. More specifically, a vendor may be unable to provide the product according to project schedule or in compliance with Toronto Hydro's specifications, thereby leading to delays or cost overruns to address the issue. In this regard, Toronto Hydro will ensure mechanisms are available to oversee and enforce contract terms and conditions. Toronto Hydro will adopt the following mitigation measures within its contracts:

    - Complete comprehensive due diligence of scope and requirements prior to undertaking projects and incorporate findings in the tender documentation.
    - Solicit vendor responses to competitive bids from qualified parties.
    - Enter into long term contracts, where appropriate, with vendors and suppliers to ensure costs are fixed over a long period of time.
    - Clearly state expected timelines and have resolution clauses to address delays.
    - Identify an escalation path to quickly resolve conflicts and discrepancies.
    - Enforce short interval control on vendor performance and deliverables through project status updates.
- **Adherence to Budget & Timelines:** If a project tracks above budget or falls behind schedule, this could take resources away from other important IT projects and delay their implementation. To address this risk, Toronto Hydro uses modern project management methods, tools, and vendor agreements to ensure on-time and on-budget project execution. Moreover, Toronto Hydro's experienced project managers will control the implementation timing of projects in accordance with each project plan and closely monitor emerging risks. Contract tools and incentives will also be incorporated to aid the management of timelines.
- **Project Delivery**: A new IT/OT System version could cause established core business processes to change and, without proper integration, could disrupt, and cause inefficiencies in these processes. Toronto Hydro undertakes extensive regression testing and user testing prior to rolling out the final upgrade to the business units. In addition, risks are mitigated through appropriate user engagement and communication, change management, training and project governance including contingencies to minimize the impact to the business users in the final implementation.

Preliminary Scoping Business Case:

Advanced Distribution Management System (ADMS) Upgrade

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1. EXECUTIVE SUMMARY

Project Name	Costs (2025-2029)
Advanced Distribution Management System (ADMS) Upgrade	$34.2 million

Toronto Hydro relies on its current ADMS to meet service quality requirements and maintain the reliability of the distribution grid. The ADMS is a software platform consisting of a suite of several software applications to assist Control Centre operators in monitoring and controlling the distribution system. Key components of ADMS include:[1]

1. the Distribution Management System (DMS);
2. the Outage Management System (OMS); and,
3. the Supervisory Control and Data Acquisition (SCADA) system.

These three systems are the foundation of the utility's core system monitoring and operation processes. DMS and OMS enable operators to manage critical functions such as the identification and response to outages, and the safe planning and execution of field work using planned or emergency switching, combined with other elements of the Utility Work Protection Code (e.g. Work Permits, Supporting Guarantees, Hold Offs etc.). These systems are essential to supporting the evolving needs of Toronto Hydro's distribution grid and its users as a greater number of households, businesses, and government organizations electrify their energy usage, and as the penetration of distributed energy resources (DERs) increases. ADMS software, in particular SCADA, analyzes information acquired from field devices, alerts system operators to adverse electrical conditions, possible inefficiencies, and reliability issues, and either assists operators in addressing these issues or performs recommended control actions automatically.

Given the criticality of these systems to Toronto Hydro's day-to-day operations and overall system reliability and security, technical upgrades to the ADMS to ensure continued vendor support are necessary to ensure business continuity and adequate protection from existing and emerging cyber security threats. In addition, many ADMS components currently operate in silos and have limited ability to communicate effectively with each other, often contributing to process delays and inefficiencies that may result in longer outages. Upgrades to ADMS will enable effective co-ordination and communication among its various components by allowing Toronto Hydro to hand pick components in order to achieve a synchronized and harmonious platform. These upgrades will also align with the utility's grid modernization objectives by supporting future automation functionalities (e.g. in support of the self-healing grid) and improving business process efficiencies through leveraging technical and functional enhancements.

[1] A detailed list of components is available in the Appendix

Upgrades to ADMS will also enable Toronto Hydro to continue to meet or exceed the Ontario Energy Board's (OEB) reliability performance standards, particularly the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). ADMS contributes to grid reliability by providing Control Centre operators the capabilities to monitor and control the distribution network in real-time and enabling a comprehensive view of the network status of all connected devices including transformers, breakers and switches. It also contributes to the achievement of service quality requirements by enabling the automatic location and isolation of faults through the Fault Location, Isolation, and Service Restoration (FLISR) function, which reduces outage response times. ADMS is also equipped with advanced diagnostics to analyze the health of the distribution system and to identify outage root causes faster.

To ensure an effective ADMS solution for Toronto Hydro, the following options were assessed:

1. **Managed Deterioration** - Maintain status quo with current ADMS software platform.
2. **Sustainment** - Maintain status quo and execute only reactive and mandatory changes to keep the ADMS systems current without undertaking an upgrade.
3. **Modernization and Growth -** Implement a modern ADMS platform by leveraging the advantages of each system in a "Multiple Vendor Approach" strategy (i.e. "best fit" vendor offerings to meet Toronto Hydro's business needs).
4. **Replacement and Harmonization** - Implement a single platform, migrating all OMS, DMS, SCADA, and Distributed Energy Resource Management System (DERMS) functionality to the one integrated vendor.

The utility evaluated each option against the following categories:

- **Strategic Risks –** Each option was evaluated for alignment with strategic criteria which included alignment with Toronto Hydro's strategic objectives such as intelligent grid, grid modernization and process automation.
- **Tactical Risks**: Each option was also evaluated against tactical considerations including operational risk, security risk, implementation risk, timeline risk and budget risk.

Based on this evaluation, Modernization and Growth is the preferred option. This option positions the utility well to ensure grid reliability, alignment with Toronto Hydro's strategic objectives, the modernization of the utility's operations, and the improvement of customer experience. In addition, this option will assist Toronto Hydro in achieving its strategic objectives.

The Modernization and Growth approach will leverage multiple vendors to identify components that best fit Toronto Hydro's needs, and ensure compatibility and effective communication between different components in order to develop a synchronized platform. This approach also enables the utility to implement planned enhancements more effectively and flexibly based on functional phases that target specific areas such as FLISR, SCADA, DERMS, etc.

The intended benefits of the ADMS Upgrade are to:

- Ensure critical operational technology platforms are fully supported by respective vendors and are resilient against cyber security threats;
- Achieve operational and safety excellence;
- Enable advanced predictive and automation capabilities to reduce the frequency and duration of outages, resulting in improved system reliability and customer experience;
- Improve grid resiliency through automated and efficient restoration of outages with minimal interruption to customers;
- Deliver streamlined and effective responses to outages with crews addressing outages more quickly in the field through automated and smart dispatching;
- Leverage new technologies to enhance the utility's ability to assess and prioritize responses to outages due to major events such as storms through a holistic view of the grid;
- Ensure optimal distribution system performance and improve customer experience;
- Enable better monitoring and control of distributed energy resources in the field; and,
- Ensure optimal utilization of IT assets by enabling effective lifecycle management of secure and supported systems, minimizing operational and cyber security risks.

2. PROBLEM/OPPORTUNITY STATEMENT

2.1 Background

The upgrade of Toronto Hydro's Advanced Distribution Management System (ADMS) platform is necessary to enable the utility to maintain and modernize critical distribution system monitoring and management processes into the 2025-2029 rate period and beyond.

Current functions and components of ADMS allow Toronto Hydro to execute a variety of processes relating to the monitoring, operation, maintenance, and general oversight of the distribution system, such as:

- identifying outages;
- scheduling responses by field crews or remotely operating components of the grid to restore outages;
- monitoring and controlling DERs connected to the grid;
- performing various tasks in support of capital or maintenance work (such as switching); and,
- coordinating the management of the utility's distribution system in alignment with the operation of the bulk transmission grid by Hydro One and the Independent Electricity System Operator (IESO).

All of these functions are essential in enabling the utility's compliance with legislative and regulatory obligations relating to customer, public, and worker safety, grid reliability, and customer service.

Toronto Hydro plans to renew the systems comprising these functions and components of ADMS during the 2025-2029 period in order to 1) ensure that vendor support remains current and available and 2) enhance ADMS with various upgrades that will improve the effectiveness and efficiency of the underlying processes. The utility expects that its planned enhancements to ADMS will be crucial for operational effectiveness as society moves towards decarbonization, increasing the pace of electrification, and as the nature and needs of customers and stakeholders interacting with Toronto Hydro's distribution system continue to evolve.

The proposed upgrade would also present opportunities for the utility to streamline the operation and integration of ADMS functions and components and manage the relevant information and operational technology (IT/OT) assets in a more cost-effective manner, in accordance with

Toronto Hydro's IT Asset Management and Investment Planning Strategy (the Strategy).[2] In addition, ADMS upgrades will provide a comprehensive path for managing assets as per the Strategy by enabling effective tracking, utilization and co-ordination among various components. Given the rapid advancement in technology, without the ADMS upgrades, current systems will begin losing access to new and existing features, security will become a greater risk and vendor support will become more difficult to maintain. In addition, ADMS is a dynamic integrated platform that depends on all components working together in a synchronized fashion. Currently, not all ADMS components can be fully integrated to communicate effectively with each other, often contributing to process delays and inefficiencies that may result in an increase in outage response times. Integration will become increasingly important as the components age and component capabilities change, resulting in gradual degradation in ADMS' ability to perform critical activities. Upgrades to ADMS will enable effective co-ordination and communication among its various components by handpicking components from multiple vendors in order to achieve a synchronized platform, enabling the utility to provide a timely and effective response to outages.

2.1.1 Application Components

Toronto Hydro's ADMS platform includes the following current operational functions (listed with possible enhancements to each function through the ADMS Upgrade project):

- Distribution Supervisory Control and Data Acquisition (SCADA) system – Enhance integration with other ADMS components and introduce more automation.
- Outage Management System (OMS) – Increase monitoring capabilities across the grid, improve productivity by automating simple dispatch transactions, and optimize the utilization of Control Centre and field resources.
- Distribution Management System (DMS) – Provide more detailed and up-to-date visibility into grid conditions.
- Distributed Energy Resource Management System (DERMS) - Enable more precise monitoring and control of distributed energy resources connected to the distribution grid.
- Overall Enhancements - Interfaces to other internal and external systems such as Toronto Hydro's Geospatial Information System (GIS) and corporate data historian, Hydro One's energy management system (EMS), and others.

2.2 Problem Statement

As previously noted, the ADMS platform is critically important to the execution of Toronto Hydro's day-to-day operations and compliance with applicable legislative and regulatory obligations

[2] EB 2023-0195, Exhibit 2B, Section D7

relating to customer, public, and worker safety, grid reliability, and customer service. The following subsections provide more details on the risks that may arise in the event that the utility does not upgrade the ADMS platform in the 2025-2029 period.

2.2.1 System Risks: Infrastructure Lifecycle

Although the current ADMS infrastructure is fully supported and optimized for existing systems, the current application and database servers are forecasted to reach end of life by 2027. Operating these assets beyond end of life would require Toronto Hydro to establish backup infrastructure that is not optimized to accommodate ADMS components and to procure specialized technical resources for maintenance purposes. These mitigation measures could cause further risks affecting the reliability of ADMS and the continuity of distribution operations. For example, if issues with the ADMS infrastructure were to materialize, the utility will have limited ability to ensure the solution will work on an outdated infrastructure. This, in turn, may present a greater risk to restoring full functionality following infrastructure failures in a timely and effective manner, jeopardizing Toronto Hydro's ability to effectively monitor and manage the distribution system.

2.2.2 System Risks: Cyber Security Protection

The systems that currently comprise the ADMS platform receive regular service packs and patches from their respective vendors, including occasional ad hoc security patches to address any critical vulnerabilities. This approach ensures that the systems remain up-to-date with the most current features and are protected against cyber security risks. However, as ADMS systems age and lose vendor support, Toronto Hydro will no longer have access to these timely updates and patches, resulting in greater exposure to cyber security threats and putting at risk the continuity and integrity of the critical functions supported by ADMS systems.

2.2.3 Business Continuity Risks

Based on Toronto Hydro's past experiences, various vendors will discontinue future investments in product updates, functional enhancements, and technical improvements in respect of the systems that currently comprise the ADMS platform, as early as 2024. If the utility is consequently unable to keep up with product standards and improved functionality, these developments may result in significant risks to the continuity, efficiency, or timeliness of critical business operations in support of outage restoration and capital and maintenance work. In addition, continuing the use of obsolete products would hinder the utility's ability to modernize its business processes in accordance with the evolving nature and needs of customers and stakeholders interacting with the distribution system, for example due to electrification. Deferring system upgrades may require Toronto Hydro to deploy alternative solutions in the meantime, which may be less effective in maintaining business processes. Furthermore, as the gaps in capabilities of different ADMS components continues to grow, the utility's ability to have these components operate in a coordinated and effectively integrated manner will become increasingly difficult, posing significant risks to process continuity, system reliability, and the effectiveness of reactive solutions. Collectively, these risks may cause adverse impacts beyond Toronto Hydro and its service territory, for example by hampering the utility's obligations to support outage restoration and participate in bulk system event management tasks in accordance with the IESO's Ontario Power System Restoration Plan.

2.2.4 Lost Efficiencies and Opportunities of Process Automation and Innovation

As the number of connections to the distribution system increase due to electrification and the nature of connections become more diverse through increased uptake of DERs, Toronto Hydro will need to invest in its tools and processes to efficiently perform both traditional system management and outage restoration tasks and emerging functions such as DER monitoring and control. Achieving continuous improvement and productivity gains in these areas will require the utility to increasingly focus on process automation and innovation. The proposal to upgrade ADMS components and other integrated systems incorporates a number of enhancements that will enable such automation and innovation, as described in greater detail in sections 3 and 5 of this document.

Without the ADMS upgrade, Toronto Hydro would lose the ability to benefit from improved product functionalities that would enable automation and associated productivity and efficiency gains. This would greatly hamper the utility's ability to achieve favourable outcomes for ratepayers, including its strategic objectives (e.g. intelligent grid, grid modernization and process automation), and to implement key technologies and initiatives that underpin the utility's modernization plan for the 2025-2029 rate period, such as FLISR.

Currently many ADMS components have limited integration with each other, hindering effective communication between systems. As these components age, the integration gaps between them will likely grow. In the future, this may impede effective decision-making and operations by Toronto Hydro and consequently affect the utility's overall efficiency. The proposal to upgrade ADMS components provides an opportunity for the utility to enable effective coordination and communication between the platform's systems by handpicking the most optimally integrated solutions.

2.2.5 Summary

In summary, Toronto Hydro expects the ADMS upgrade to add value and address risks relating to the following areas:

- ✓ **Monitoring the distribution system:** ADMS provides the utility with a real-time network model. Without it, Control Centre operators would lack an efficient and reliable way to understand the state of the distribution system. Furthermore, as DER penetration increases, the utility may need greater visibility into system parameters (e.g. DER outputs, power flows, localized voltage and current, etc.) to better monitor and manage the safety and reliability of the grid.

- ✓ **Responding to all emergencies in accordance with legislative and regulatory requirements:** Improvements to OMS and other components would enhance the utility's ability to efficiently identify and prioritize grid emergencies.
- ✓ **Outage restorations:** The implementation of enhanced automation and system aided switching through components such as FLISR would be critical to achieving continuous improvement in the utility's ability to prioritize and schedule actions to restore power and remedy outages.
- ✓ **Dispatch and grid response functions:** Solutions such as automated dispatching and route optimization would enhance the utility's decision-making and organization processes for assigning Control Centre and field resources to both emergency response and planned activities.
- ✓ **Safety:** Enhanced functions under ADMS would facilitate compliance with safety requirements (e.g. under the Utility Work Protection Code) and enable effective auditing of relevant records.
- ✓ **Grid Analytics and System Planning:** Upgrades to the ADMS would supply the utility with more sophisticated tools to proactively monitor the grid performance, analyze opportunities for improvement, and effectively plan for actions and investments to improve grid resilience and capacity. Furthermore, such solutions would be more responsive to challenges posed by increasing volumes and types of DERs such as battery storage, electric vehicles, and distributed generation.

3 BUSINESS REQUIREMENTS SUMMARY

This section provides a high-level summary of the requirements for the ADMS upgrade to meet business needs and align with strategic objectives. A detailed list of functional requirements can be found in Section 5, the Appendix to the Business Case document.

As this business case is described at a program level, this may lead to multiple phases and releases that will encompass it. As such, considerations such as execution strategy will help determine the prioritization of the below requirements.

ADMS Requirement Categories	High Level Requirements
Intelligent Grid	• Automated FLISR/Self-Healing Grid - Automatically operating devices in the field to restore power to customers and minimize outage duration. • Improve outage resolution by leveraging fault location analytics (FLA) capabilities which use real time data and predictive algorithms that makes outage restoration more efficient • Gather real-time grid data via SCADA to help identify grid weaknesses and assist with evaluating level of outage risk • Improve the quality and reliability of field data available to Control Centre operators and meet reliability performance targets • Support remote terminal unit (RTU) testing • Support multiple communication protocols, standards and data acquisition techniques • Support multiple control actions • Exchange data with other systems in real time
Process Automation	• Enable automation where possible within dispatching to improve execution of planned and un-planned activities • Introduce training simulator for staff to improve the management of storm events

Customer Experience	• Improve outage management processes to achieve:
	  o Greater situational awareness regarding outages
	  o More accurate and timelier provision of estimated times of restoration and outage map updates
	  o More effective damage assessment leading to faster outage resolution

ADMS Requirement Categories	High Level Requirements
	○ Improved grid response processes to restore power to as many customers as possible, as quickly as possible
IT Asset Management	• **System Currency** - Keep up to date with system upgrades and retain effective system support • **Cyber Security** - Ensure security risks are identified and mitigated or minimized by aligning with industry and technological best practices • **Performance** - Ensure appropriate level of performance that allows the efficient use of system tools by all system users, particularly during storm situations • **Improved release management** - Take advantage of system solutions that support high availability, resulting in fewer planned IT system outages.

*Detailed list of requirements is available in Appendix

3.1 Assumptions & Dependencies

The following assumptions underpin the scope of the ADMS Upgrade project. Any change in the assumptions will require a reassessment of the project scope, timelines, and costs.

- The existing integration between various ADMS components will remain intact until a new specific ADMS system component goes live.
- Other non-ADMS systems (e.g. GIS, the Customer Information System, etc.), impacted by the project will remain unchanged until a new specific ADMS component goes live.
- No new and major technological developments that impact ADMS and its underlying infrastructure will emerge for the duration of the project.
- No new and major functional or technical requirements will emerge for the duration of the project.
- There will be no change in the organizational direction to the overall project approach as described in this Business Case document.

4. OPTIONS ANALYSIS AND RECOMMENDATION

Toronto Hydro engaged various internal and external stakeholders to evaluate a number of options to address the problems and opportunities outlined in Section 2 of the Business Case.

The utility considered available solutions and processes to identify challenges and opportunities, and to establish baseline requirements and objectives.

The utility also invited industry leading ADMS vendors to showcase their solutions, which allowed the evaluation of new technologies against existing and future business needs, the refinement of product evaluation criteria, and the identification of additional requirements and considerations.

This exercise helped Toronto Hydro in identifying the four options discussed below. The utility assessed these options against the evaluation criteria presented in Subsection 4.2, ensuring alignment with applicable strategic objectives and IT/OT standards. The following subsections provide details of the options considered and the rationale supporting the selected option.

4.1 Options Analysis

Option 1 – Managed Deterioration

In this option, Toronto Hydro will continue to work with existing ADMS systems with no enhancements, upgrades, new integrations, or patches. The utility will continue to run systems past their end-of-life and address defects on a best efforts basis only, with the limited capabilities available.

As this option focuses solely on maintaining status quo with respect to existing systems, it represents the least expensive option in terms of upfront capital investments and initial operational costs. However, this option poses a high degree of risk due to degrading system performance and system currency as well as increasing cyber security concerns. This option would eventually result in a gradual degradation of operational capabilities due to decreasing levels of vendor support for current systems. From a cyber security standpoint, this option would lead to increased vulnerability to cyber attacks due to the lack of vendor-supplied security patches, increasing the likelihood of more frequent and severe disruptions in day-to-day operations. Ultimately, this is not a sustainable option, as it would lead to significant deterioration of operational resiliency.

The increasing operational and security risks that would accumulate over time under this option far outweigh the low implementation costs, and budget and timeline risks. Over time, the utility's inability to address system vulnerabilities may lead to increases in cyber security breaches and a subsequent decrease in business process efficiencies. Limited and degrading vendor support and maintenance can also lead to longer and more frequent system breakdowns of ADMS systems, hampering distribution system management and operations and resulting in lower customer satisfaction and inability to meet legislative, regulatory, and performance requirements relating to safety and reliability. In addition, resourcing legacy applications is challenging. Currently, ADMS technical resources are focusing on updating their skill sets for new ADMS component versions, which shrinks the pool of resources that will be available in the future to support legacy applications. Externally, ADMS vendors will shift their support pool to the latest versions and support for legacy versions will become increasingly limited or unavailable after 2028.

Finally, this option does not allow Toronto Hydro to support its grid modernization objectives by enabling process automation and advanced features that will become available through newer versions of ADMS components, as the utility would continue running its current systems past the point of obsolescence. This outcome would present a lost opportunity in terms of achieving greater process efficiencies and productivity gains, and leave Toronto Hydro's distribution system ill-prepared to meet the challenges presented by evolving consumer preferences and industry conditions, such as electrification or increasing DER uptake.

Option 2 – Sustainment

In this option, Toronto Hydro will maintain status quo with respect to existing systems, and be able to sustain day-to-day operations, in a limited capacity, by relying only on the minimum infrastructure, application upgrades, and security and system patches, for as long as they are available.

This option has the advantage of low up-front capital expenditures and would only require minimal investments in change management actions required to sustain the utility's day-to-day operations. However, over time this may result in increasing operational costs associated with obtaining vendor support and having to manage greater exposure to cyber security threats. While this option would maintain short term system currency and operational resiliency, Toronto Hydro would find it increasingly difficult and costly to sustain old technologies with fewer upgrades and patches from declining vendor support to maintain adequate levels of security and system reliability. The inefficiencies from the lack of integration between legacy systems would continue and attempting to integrate them further as they age would be costlier and carry a higher chance of system failure.

This option also does not allow Toronto Hydro to support its grid modernization objectives by enabling process automation and advanced features that will become available through newer versions of ADMS components, as the utility would only maintain currently available functionalities. Without access to new features and functions, current systems may be unable to adapt to customers' evolving needs and preferences in to the context of emerging industry trends such as electrification or increasing DER uptake. In addition, this outcome would present a lost opportunity in terms of achieving greater process efficiencies and productivity gains.

Option Three – Modernization and Growth (Recommended Option)

In this option, Toronto Hydro will implement a modern ADMS platform by upgrading its component systems and leveraging the advantages of each system through procurements with multiple vendors, which would allow the utility to acquire the most optimal technologies for OMS, DMS, SCADA, and DERMS. This option will involve upgrades to the latest version of each specific system, while continuing to enable more advanced capabilities such as FLISR and artificial intelligence with an agile implementation approach.

Furthermore, this option will allow the utility to achieve targeted benefits using a phased approach. By relying on multiple vendors and workstreams, Toronto Hydro can realize benefits as each project phase is completed. This option will also take advantage of new technologies and vendor solutions that will address the risks outlined in subsection 2.2 and meet the business requirements outlined in section 3.

This option will require moderate capital expenditures for implementation and relatively higher operational costs to maintain multiple systems and vendors, as well as user training and knowledge base management across several different platforms. However, the incremental operational costs would be partially offset thanks to lower needs of operational change management, through the proposed strategy of upgrading current systems on an ongoing basis. In the long term, this option would also allow Toronto Hydro to holistically balance and optimize project costs (capital and operational) and business units' operational costs by pacing and tailoring the selection and implementation of particular upgrade solutions in accordance with the urgency of business needs, rather than having to invest in all system upgrades all at once under a one-vendor approach.

This option would maintain vendor support through the proposed system upgrades and consequently result in lower cyber security and operational risks, as access to vendor-supplied enhancements, upgrades, and, patches would serve to strengthen the organization's cyber security posture and reduce the likelihood of operational disruptions.

This option would also allow Toronto Hydro to support its grid modernization objectives by enabling process automation and advanced features that will become available through newer versions of ADMS components. The multiple vendor approach would enable the utility to procure solutions in a more flexible and customized manner in accordance with the business needs underlying each upgrade. These solutions, in turn, would yield process efficiencies and productivity gains (e.g. through the implementation of FLISR and the self-healing grid), and put Toronto Hydro in a much better position to respond to emerging industry trends such as electrification or increasing DER uptake. Finally, this option would provide opportunities to improve integration and communication among ADMS' various systems by handpicking components from multiple vendors to achieve a synchronized platform, laying the groundwork for future enhancements.

Option Four - Replacement and Harmonization

In this option, Toronto Hydro will migrate all OMS, DMS, SCADA, and DERMS functionalities under one integrated vendor. This option would pose significantly higher change management risks as all business processes currently dependent on ADMS systems would require modifications and some of the previously integrated enhancements would require re-implementation under the selected vendor's solutions. This option would offer several benefits from the adoption of a single integrated system such as uniform user experience, lower integration and ongoing sustainment costs. However, these benefits would be offset by the higher up-front capital investment required to redo and redesign unique customizations and configurations. In addition, this option will require significant retesting and extensive change management including user retraining, changes to operational procedures and related documentation, employee communications, all contributing to longer implementation timelines. Realizing the benefits of the system upgrades would take approximately 2-3 years longer than under Option 3 due to the migration to a single platform. Implementation would also be subject to higher timeline and budget risks due to reliance on a single vendor. Finally, to the extent that this option were to require the early replacement of any ADMS component before end of life, it would result in suboptimal utilization and value from previous investments, to the detriment of ratepayers.

4.2 Evaluation Criteria

Toronto Hydro evaluated each option based on the following strategic criteria:

1. **Alignment with Strategic Objectives:**
    a. Intelligent grid & grid modernization
    b. Process automation
    c. Customer choice
    d. Customer experience
    e. IT asset management
2. **Grid Reliability**: Measure of ADMS systems' ability to support operational processes feeding into grid reliability, distribution during peak times for electricity use, the reduction of outage durations, and the automation of outage response.
3. **Cyber Security**: Overall assessment of cyber security configuration and capabilities.
4. **Environment and Safety**: Concurrence with legislative and regulatory obligations and utility and industry standards relating to health and safety.

5. **Change Management**: Amount of effort required to prepare and enable the organization and users to adapt to the new systems/processes
6. **Cost**: Overall implementation and sustainment costs
7. **Timeline**: Overall timeline to project completion and the achievement of projected benefits
8. **Overall Risk:** Denotes the holistic assessment of previously described strategic risk categories

The utility assessed each of the above strategic risks under the four options as follows.

Table 1: Evaluation of Strategic Risks

Options/Criteria	Alignment with Strategic Objectives	Grid Reliability	Cyber Security	Environment and Safety	Change Management	Cost	Timeline	Overall Risk
1. Managed Deterioration								
2. Sustainment								
3. Modernization and Growth								
4. Replacement and Harmonization								

Legend	Exceed Criteria	Meets Criteria	Partially Meets Criteria	Does Not Meet Criteria

Toronto Hydro also evaluated each option based on the following tactical criteria:

1. **Operational Risk:** Risk of disruption to the day-to-day business activities of the utility
2. **Security Risk:** Cyber security and other types of security risks
3. **Implementation Risk:** Risk of challenges to system/project implementation due to difficulty and/or complexity
4. **Timeline Risk:** Risk that project tasks and deliverables will take longer than forecasted
5. **Budget Risk:** Risk that costs for the project will be higher than forecasted due to unexpected expenses, delays, or increases in scope

Table 2: Evaluation of Tactical Risks

Options/Criteria	Operational Risk	Security Risk	Implementation Risk	Timeline Risk	Budget Risk	Overall Risk
1. Managed Deterioration						
2. Sustainment						
3. Modernization and Growth						
4. Replacement and Harmonization						

Legend	Exceed Criteria	Meets Criteria	Partially Meets Criteria	Does Not Meet Criteria

4.3 Evaluation Summary and Recommendation

As outlined in subsections 4.1 and 4.2, Toronto Hydro is recommending the Modernization and Growth option (option 3). This option will enable Toronto Hydro to continue attaining the benefits offered by the ADMS platform by keeping its systems current and its vendor support intact, while also unlocking future benefits in support of grid modernization and process automation in the most flexible and cost-effective manner.

The Modernization and Growth option positions the utility well to meet a range of grid reliability and health and safety outcomes by maintaining the key ADMS systems supporting relevant business operations and enabling their continuous improvement. Although the Replacement and Harmonization option will also contribute to reliability and health and safety outcomes, the previously discussed implementation challenges associated with that option may put those outcomes at risk. While the Sustainment option also serves to maintain the status quo with respect to reliability and safety criteria, it is unlikely to provide optimal support for reliability and health and safety outcomes (e.g. employee and public health and safety, compliance with relevant legislative and regulatory requirements) in the long term as this option will restrict ADMS system upgrades to the bare minimum. The Managed Deterioration option represents the most significant risk to reliability and health and safety outcomes, as the deterioration of ADMS systems and the lack of vendor support would greatly increase the likelihood of disruptions to the related business processes depending on ADMS.

Due to the increasing number and sophistication of threats, cyber security continues to be a growing concern for many utilities. The Managed Deterioration option ranks the lowest in this regard as the deterioration of ADMS systems and the lack of vendor support under this option would greatly increase cyber security risks. Although maintaining the status quo under the Sustainment option allows the system to maintain the existing level of protection from cyber security threats in the short run, restricting system upgrades to the bare minimum overtime will hinder the utility's ability to ensure adequate protection of the ADMS platform against threats in the evolving cyber security landscape. Both the Modernization and Growth option and Replacement and Harmonization options would position the utility well against current and emerging cyber security threats through the system upgrades contemplated under those options.

The Modernization and Growth option supports the adoption of emerging technologies and new functions which align with Toronto Hydro's grid modernization and process automation initiatives (e.g. through the implementation of FLISR and the self-healing grid). Although the Replacement and Harmonization option also aligns with these strategic objectives, it is a suboptimal solution because of the lack of flexibility resulting from the single vendor approach contemplated under that option. In order to leverage the technology solutions that best-fit the utility's business needs and enhance the overall customer experience, Toronto Hydro adopted a multiple vendor approach under the Modernization and Growth option. This option also contemplates the achievement of better integration and communication among ADMS' various systems, it is well-poised for enabling future enhancements, despite the greater diversity of systems and components compared to the Replacement and Harmonization option. In contrast, the restricted approach to system upgrades under the Managed Deterioration and Sustainment options will hamper the utility's adoption of new technologies and functions in alignment with strategic objectives, jeopardizing the evolution of underlying business processes.

With respect to change management, timelines, and budget, the Managed Deterioration option fares best, as it would minimize capital expenditures, change management activities, and execution risks. The Sustainment option also presents a lower risk profile with respect to these criteria. For example, in the short term the need for change management would be minimal from maintaining existing systems. However, in the long-term Toronto Hydro would find it increasingly difficult to maintain current systems as they reach end of life and vendor support diminishes. Ultimately, both the Managed Deterioration and Sustainment options involve other types of unacceptable risks and shortcomings that offset the relatively lower change management, timeline, and budget risks. The Replacement and Harmonization option is the least favorable in terms of change management, timelines, and budget, as implementing a single vendor solution to meet all functional needs would likely require higher up-front capital costs and more extensive change management, resulting in longer implementation timelines (See Section 4.1 for more details). The Modernization and Growth option represents the optimal balance with respect to these criteria as it would holistically mitigate financial and operational risks by leveraging individual vendor capabilities through competitive procurement and implementing smaller, targeted initiatives over multiple phases instead of larger and more complex initiatives during a shorter period of time. Under this approach, Toronto Hydro would also retain the flexibility to implement better integration and communication among ADMS' various systems. In this sense, the Modernization and Growth is also the option that best aligns with Toronto Hydro's IT Asset Management and Investment Planning Strategy.

In implementing the Modernization and Growth option, the first step would be the discovery and documentation of the current state and detailed business and technical requirements. Then, Toronto Hydro would assess each requirement and design a suitable solution. This process would likely involve multiple steps as different system upgrade projects are awarded to different vendors. The utility expects the majority of the work and costs to occur in the various implementation phases.

Under this option, the ADMS Upgrade would constitute multiple projects with different delivery dates. This would enable Toronto Hydro to realize the benefits of each element as it is implemented as some of the planned system upgrades and enhancements would benefit from synergies with current initiatives in the 2020-2024 rate period. In addition, multiple projects will be run simultaneously by multiple teams working in parallel as opposed to a single team working on each phase of a project one at a time. This approach is expected to lead to greater cost savings and improve time management.

The multi-phase implementation of upgrades by multiple different vendors under the Modernization and Growth option will require significant testing to successfully integrate different solutions. This effort will contribute towards mitigating the timeline and budget risks associated with this option.

The Modernization and Growth option will require the utility to manage change management at the program level with each phase/project involving tailored training, staff communications, and other change management activities. Since many of these changes will reflect upgrades associated with existing system components, the costs of such change management activities will be modest.

In summary, the Modernization and Growth option is the most favourable option for both mitigating the strategic and tactical (project) risks outlined in previous sections of the Business Case document and supporting Toronto Hydro's achievement of favourable outcomes for ratepayers in the short and long term.

Table 3: Breakdown of Estimated Program Costs

Program Phase	Description	Cost
Initiation and Discovery	• Prepare for execution and kick-off initiative(s) • Document and assess current state processes • Establish and gain approval on detailed requirements	$4.1 million*
Blueprinting	• Assess and confirm functional options and decide on solutions • Establish and gain approval on future state processes • Establish methods for confirming and monitoring benefits	$4.5 million*
Build & Implementation	• Develop/configure/formulate solutions • Conduct testing • Train stakeholders	$21.3 million*
Launch	• Establish means for operational support • Launch solution and deliver on post go-live launch strategy • Prepare for initiative closure and sustainment	$4.3 million*
Total		$ 34.2 million*

*All costs account for inflation

5 APPENDIX

This section provides a detailed description of the requirements by area:

<table>
<tr><th>ADMS Features and Components</th><th>Requirements</th></tr>
<tr><td>User Interface</td><td>

The users shall interact with the ADMS components via workstations installed at the Control Centre and various other locations.
The user interface (UI) shall allow authorized personnel to:

view measured and calculated real-time and near real-time, outage information (including vehicle and crew locations);
view Distributed Energy Resource (DER) information;
view historical outage and load data;
initiate control actions (with suitable security limits and controls); and,
interact with the ADMS applications.

UI includes Areas of Responsibility (AORs) that shall provide the means to route alarms, restrict supervisory control, restrict data entry, and enable data viewing to those personnel having the associated responsibility and authority.
As a minimum, the ADMS displays shall include:

Tabular displays
Trend lines
Displays containing bar charts, pie charts, and other mechanisms to view equipment status and trends
Single-line schematic diagrams showing the configuration, status, and loading of the distribution feeders, substations, and other power system facilities
Map-style displays showing properly scaled and geographically correct depictions of distribution lines overlaid on street maps. It shall also be possible to view dynamic data
Satellite style displays (e.g. Google Earth) containing similar information as map-style displays
Application function displays (alarm displays, video trend displays, and displays used to interface with the ADMS application functions)

</td></tr>
</table>

<table>
<tr><th>ADMS Features and Components</th><th>Requirements</th></tr>
<tr><td></td><td>8. System management and diagnostic displays (security administration, system configuration, on-line/offline diagnostics, etc.)
• Users shall be able to add operator notes containing free-form text associated with a specific device or ongoing outage.
• On demand, the user shall create a simplified schematic display using the geographic information from GIS.
• The User Interface security settings shall comply with Toronto Hydro security policies, standards and procedures.
• This feature shall include Alarm Processing functions to alert system users to abnormal conditions on the power system. The Alarm Processing function shall also alert system users to ADMS and communication equipment failures and other abnormal ADMS conditions requiring attention.</td></tr>
<tr><td>DMS</td><td>• DMS includes a single Distribution System Operations Model (DSOM) that supports all distribution applications, including advanced distribution applications, outage management, and DERMS.
• DMS includes load profiles for estimating the load for a given time/date for each different type of customer (residential, commercial, industrial, etc.).
• DMS shall be a single centric process that supports model updates for all applications.
• DMS shall enable a user to add, modify, or remove temporary elements to the Distribution Network Model through the operator user interface.
• DSOM shall include Information for schematic displays of the electrical facilities, showing individual elements and interconnections, along with the operating state and other related information. It shall display current and nominal state.
• The DSOM function shall include an Impedance Calculation application that shall calculate the impedance of overhead and underground line segments needed for the execution of other applications such as Unbalanced Load Flow and Fault Location.</td></tr>
</table>

ADMS Features and Components	Requirements
	• This component shall support a full-featured study mode environment that shall enable the user to execute any ADMS application (including DMS, OMS, and DERMS applications) to determine the impact of proposed operating actions and changes to the power system configuration in an "off-line" mode. • Network Topology Processor: shall use the DSOM connectivity model to determine the dynamic network connectivity and the energized, de-energized, looped, paralleled or grounded status of power system components, and DSOM shall visually represent these states. • DMS shall include suitable mechanisms for determining the real and reactive power on each distribution service transformer at any given time. • The component shall include facilities for determining the output of each distributed generating unit that is connected to the distribution system. • The Distribution Unbalanced Power Flow (UBLF) shall use the DSOM to calculate the electrical conditions (current, voltage, real and reactive power) for the entire distribution system. • This component shall include a Distribution State Estimation (DSE) application for calculating the distribution network state • This component shall include a short circuit analysis (SCA) application function that shall be able to compute short circuit currents for faults of all types. • The FLA function shall determine the approximate location of faults on distribution feeders. • FLISR shall be a model-driven solution that uses the as-operated distribution system model and topology processor, along with the status of circuit breakers, line reclosers and other feeder switches, fault detectors and faulted circuit indicators to determine an appropriate switching strategy to isolate the faulted feeder segment and restore service to as many healthy (un-faulted) sections as possible.

ADMS Features and Components	Requirements
	• Optimal Feeder Reconfiguration (OFR) function shall define optimal network configuration required for achieving one or more user-specified business objectives. • DMS shall include Volt-Amps-Reactive (VAR) Optimization functionality • DMS shall include load and generation forecasting (LGF) functions that are able to predict real and reactive load and generator output in the near future. • The Distribution Contingency Analysis (DCA) function shall identify and evaluate the impact of contingencies on the distribution network and recommend control actions capable of limiting their impact. • The ADMS Switch Order Management (SOM) function shall support the creation, execution, display, modification, maintenance, printing, and emailing (manual and automated) of switching orders containing a list of steps needed to support various work activities, and indicating executing field resources. • Customer Network Status Tracking System (CNSTS) Displays - The ADMS shall be able to generate tabular displays of customer/network connections to a user specified feeder, including associated (alternate) feeders in a dual radial/network feeder configuration. Toronto Hydro system operators will use the CNSTS display to perform feeder isolation. • The user shall be able to apply a tag to a single point, group of points, or all points in an RTU or in a substation (except for "limit override" and "normal state override" tags), to non-telemetered points, and to calculation points. When a tag has been applied to a point, a tag symbol separate from the quality code symbol shall be presented next to the tagged point on any display or report where the point is presented. • DMS shall include a Confined Space Hold Off function to prevent a feeder from being re-energized if there are any crews working in Confined Spaces on that feeder. • DMS shall record all of the information that is needed to precisely calculate the key reliability metrics that are tracked by Toronto

ADMS Features and Components	Requirements
	Hydro, to display these metrics in dashboard, and support data extraction into Business Intelligence (BI) for data analytics.
OMS	• The OMS function shall assist system operators in identifying customer outages, determining the approximate location of the outage, dispatching first responders, coordinating restoration activities, and confirming that power has been successfully restored to all affected customers. The OMS shall also assist in gathering data needed to compute outage statistics. • The OMS shall include a complete set of tabular, schematic, and geographical displays to allow authorized OMS users to view all outage related information and interact with the OMS applications. • The OMS display system shall include a set of application functions for locating user specified items that enables the user to rapidly navigate to specified locations such as a specific asset (e.g. a transformer, line switch, or fused cut out), a specific street address, or other location. • The OMS shall be able to acquire real-time inputs from field devices via Toronto Hydro's existing SCADA communications network, Inter-Control Centre Communication Protocol (ICCP) link to the Hydro One EMS, and other sources of near-real-time data used by Toronto Hydro. The OMS shall use this near-real-time information for detecting and predicting outages. • The OMS shall include a report writing package that is able to generate ad hoc and predetermined reports containing outage information and statistics for a user-defined time frame, specific equipment, customer, circuit, cause or system wide, for user defined time frames, specified areas, substations and feeders. • The OMS shall include several mechanisms for determining that an outage has occurred. As a minimum, these mechanisms shall include: 1. Telephone "lights out" calls from customers and other sources 2. Last gasp messages for Toronto Hydro's Advanced Metering Infrastructure (AMI) system 3. Operation of SCADA monitored/controlled circuit breakers, reclosers and other remote controlled and automated switchgear

ADMS Features and Components	Requirements
	4. Entries in Toronto Hydro's outage map website 5. Direct manual entries by the dispatcher 6. Toronto Hydro external website/app allowing customers to report outages 7. Customer outage calls reported from Interactive Voice Response System (IVR) • When outage information is received from more than one premises, the OMS shall group the calls, messages, and data that appear to be part of a single power system disturbance by applying user-specified rules. OMS should allow user to configure these grouping rules based on type of event (Real Outage versus Planned Switching) and time between events. • Once the trouble calls and AMI messages have been grouped, the OMS should use the "as operated" connectivity/topology model of the distribution feeder to trace upstream from the grouped outage call/message locations to the next fault interrupting device (fuse, recloser, circuit breaker) that is upstream from the customers who are experiencing an outage. • The OMS shall include a Damage Assessment function that Toronto Hydro will primarily use during major events (especially those requiring special incident response/storm centres) for managing a group of resources that are responsible for damage assessment. • The OMS shall have a function to automatically produce an Estimated Time of Restoration (ETOR) for each identified outage event. This function shall automatically calculate an ETOR for every outage that is predicted by the OMS. • The OMS should support receiving ETORs from mobile crews and dispatchers as well as automatic creation. • The OMS shall have a Crew Management module that enables the Trouble Dispatcher to manage crews, allocate/re-allocate resources, track contact information and their history of all previous calls and whether they were reached, whether they came in, or declined when called. This module should support different types of crews (e.g. System Response, Power Lineman, Metering, Forestry, Supervisors, etc.) • The OMS shall have a module for managing call backs to customers who have been restored following a power outage or interruption. This should

ADMS Features and Components	Requirements
	be done through callback, text or email update depending on customer preference. • During widespread outages that impact multiple locations, the OMS shall be able to sort and filter the outages to ensure that the most urgent incidents are addressed first. Prioritization of restoration activities shall be performed automatically by the OMS. • The OMS shall be able to manage "planned" outages that are scheduled in advance by Toronto Hydro to perform routine maintenance, repair work, new construction, and other activities. • The OMS shall track and record "momentary" interruptions that last less than a minute, which are often caused by the operation of circuit breakers, line reclosers, and distribution automation (DA) facilities • OMS shall support the future addition of a full-function Interactive Voice Response System (IVR). • The OMS shall be able to support Mobile Workforce Management (MWM) in order to reduce operation cost, enable more effective distribution system and asset management, and improve customer service by improving the management and dispatch of field personnel • The system shall provide mechanisms for managing incidents that do not result in outages but require controller attention and possible follow-up action, damage assessments including, foreign object on powerline, leaning pole, broken guy wire, etc.
SCADA	• SCADA shall be able to acquire real-time information from various sources, including: 1. Substation automation systems, RTUs, and Data Concentrators 2. Feeder devices that are equipped with SCADA communication facilities (remote controlled switches, line sensors, etc.) 3. Energy Centre (DERMS) via secure ICCP (two way) link 4. Hydro One Energy Management System via ICCP (two way) link 5. Oracle Network Management System (NMS) via ICCP (one way) link 6. Schneider ION PQ meters via cloud communications • The SCADA Administrator shall be able to put an RTU or individual points in the RTU in a test mode that will provide the capability to monitor,

ADMS Features and Components	Requirements
	transmit, and receive messages on a communication channel, RTU, and individual point basis. • All data acquired from the power system, all real time calculated values, and all manually entered data for non-telemetered points, as well as parameters to be output to field devices, and parameters that control the operation of real-time application programs shall be stored in a comprehensive system real-time database (RTDB). • The RTDB shall be the central interface between all elements of SCADA including the data acquisition software and the user interface software for real time information. • To facilitate flexible assignment of operational responsibilities to operators, the capability to associate the field devices with Areas of Responsibility (AOR) shall be provided. • The SCADA system will support multiple communication protocols and standards, and data acquisition techniques. • Data retrieved from RTUs shall be immediately checked for certain basic error conditions including incorrect response, data buffer overwrite error, and invalid message security codes. All detected errors shall be recorded for maintenance purposes. • Data acquired from RTUs as well as data received from other data sources (e.g. ICCP data) shall be processed and placed in the RTDB as soon as it is received. • Status data shall be processed for every scan period when such data is received to determine if changes have taken place. • The Operations Monitoring function of SCADA shall track the number of operations made by every breaker, capacitor switch, recloser, and load break switch that is monitored by the ADMS. • SCADA shall include analog and status “pseudo” points whose value or state is manually inserted or calculated by performing arithmetical and/or logical operations on the values or states of other system input variables and other pseudo points. • SCADA shall include "pulse accumulator" points representing the number of times an associated piece of power equipment has changed state. • Any data received from other systems through ICCP links and secure ICCP links shall be processed using the same data processing methods

ADMS Features and Components	Requirements
	as telemetered points. Data items shall be checked for reasonability as soon as it is received. • SCADA shall control power system apparatus located at distribution substations and field locations (out on distribution feeders). This component shall support the following types of control actions: 1. Digital outputs: on/off control commands that activate control output contacts 2. Analog outputs: control commands that activate a voltage or current signal whose magnitude varies with the desired level of control 3. Setpoint control: change the settings in an intelligent controller associated with the device being controlled • Tags: It shall be possible to assign any of the following supervisory control inhibit properties to each tag type: 1. All controls allowed 2. Control inhibited in one direction, such as “Close” function 3. Control inhibited in the other direction, such as “Trip” function 4. All controls inhibited • Control Command Validations: The request shall be rejected by the system if: 1. The device is not subject to supervisory control of the type being attempted. 2. The requested control operation is inhibited by a tag placed on the device. 3. An Uninitialized, Failed, Deactivated, or Manually Entered data quality indicator is shown for the device. 4. The user’s AOR does not permit this action. 5. The Operating Mode of the workstation attempting control does not permit supervisory control. 6. A control request for the same device from another workstation is still pending (i.e. the request is not yet executed or the commanded control is not yet completed).

ADMS Features and Components	Requirements
	7. A control request for a device is in a direction that is not allowed (i.e. single sided control where the device is defined to only be controlled in one direction). • The system shall include the capability to define pre-operational checks • SCADA shall be able to exchange real-time data with other systems. The communication for these data exchanges shall be International Electrical Commission (IEC) 60870-6 TASE.2, and shall be in compliance with the ICCP security requirements in IEC 62351-3 and IEC 62351-4 for those external systems that also support secure ICCP.

DERMS	• DERMS shall be able to monitor and control customer-owned and Toronto Hydro-owned DERs that are connected to the electric distribution portion of the electric grid. DERs managed by DERMS shall include distributed generators (cogeneration, combined heating and power, microturbines, etc.), intermittent renewable generators (solar photovoltaic (PV), wind, etc.), energy storage, controllable loads (demand response), and electric vehicles (EVs).
	• DERMS shall include secure and convenient mechanisms for viewing real time, historical, and forecasted information, alarms and events, reports and logs, and other information about the DERs and for interacting with the DERMS application functions.
	• DERMS shall support a variety of techniques for controlling DERs including, but not limited to:
	    • Direct control of active and reactive power at the DER point of common coupling
	    • Set a voltage reference value, power angle, and schedule for operational VAR limits/settings
	    • Modify maximum volt-amp limits/ settings
	    • Switch DERs from autonomous control to remote control
	    • Establish a fixed schedule for operating the DER
	• All DER control actions shall be accomplished through SCADA using RTUs installed at each DER location
	• DERMS shall enable system operators to initiate changes in the DER output level.

ADMS Features and Components	Requirements
	• It shall be possible to analyze DER operations and impacts of distribution system operation in "study mode" which allows the user to switch DERs on and off, change the output level, and perform other possible changes without impacting the real time (Live) operation of the electric distribution system. • [redacted] • Modeling: DERMS shall maintain awareness of DER ratings and limitations and shall be able to enforce operating requirements from technical studies which are written into the contract. As a minimum, DERMS shall be able to enforce limits on operating power factor, voltage, frequency, ramp rates, charging and discharging limits (storage only), and power quality requirements. If ratings are violated, DERMS shall generate an alarm to alert the operator of this condition.

ADMS Features and Components	Requirements
	• DERMS shall include facilities for storing (archiving) and later retrieving historical DER operational data. • Forecasting: DERMS should be able to supply DER Generation forecasts for various time intervals, including short term (next hour), middle term (next few days), and long term (next week or longer). • DERMS shall be able to monitor and control customer-owned and Toronto Hydro owned microgrids comprised of a set of interconnected DERs in a well-defined portion of the electric distribution system. DERMS shall be able to initiate "planned" transitions of the microgrid from grid-connected to islanded mode of operation. • DERMS shall provide mechanisms for registering customer-owned and Toronto Hydro owned DERs so that these DERs can be monitored and in some cases controlled by DERMS. DERMS shall also facilitate incentive payments for verified services provided at Toronto Hydro's request during system events (e.g. emergency load shedding). • DERMS system should support transactive energy concepts as well as the economic and control techniques used to manage the flow or exchange of energy within an existing electric power system in regards to economic and market based standard values of energy.
Training Simulator	• The Dispatcher Training Simulator (DTS) shall include playback mode and interactive (simulator) mode. Playback mode shall enable the user to examine previously-recorded data in view-only mode. Interactive mode shall enable the user to view information computed by the simulator in response to a simulated event (e.g. a fault), enter simulated control commands, and view the simulated power system response to these commands. • When operating in playback mode or interactive simulator mode, it shall be possible to simulate all types of data items that are available in the ADMS, including time series SCADA inputs and calculated data items, customer outage calls, AMI last gasp messages, available crews and crew locations, and DER operation (distributed generators, energy storage, and controllable loads (Demand response)). • The DTS shall enable the user to view dynamically updating information on any ADMS display that contains the information in question, such as

ADMS Features and Components	Requirements
	tabular displays, graphical displays, trend lines, satellite (Google Earth) displays, and any other available ADMS display format. • The DTS shall allow Toronto Hydro to simulate the operation of all SCADA, OMS, DMS, and DERMS application functions and displays in interactive simulator mode. • The DTS shall support multiple simultaneous trainers and trainees. • The DTS interactive simulator mode shall use a power system model to determine how the actual power system would react to random trainer-initiated events. • The System's trainer module shall contain trainee evaluation tools to facilitate assessment of the trainee’s performance. These tools shall monitor the ability of the trainee to respond to events such as overload violations and outages. At the end of each session, the system shall provide trainers with customizable reports on trainee performance.

Preliminary Scoping Business Case:

SAP ERP Upgrade

Table of Contents

1 Executive Summary

Project Name	Capital Expenditure
SAP ERP Upgrade	$ 28 million

Toronto Hydro uses SAP's Enterprise Resource Planning (ERP) system. The ERP system supports a number of cross-functional critical organizational processes such as customer connections, event management, and meter to cash. The SAP system is highly integrated with a number of core information technology (IT) systems that support key organizational processes such as health and safety, and asset management. The ERP is a critical Tier 1 application as operations across a number of different business units significantly depend on the ERP system's workflows, data, and reports.

The current version of the SAP ERP system will reach end of life by 2027. A system that is within the vendor support lifecycle receives the latest security patches and service packs. This helps protect the system from existing and emerging cyber security threats and keeps the system compatible with the underlying infrastructure, ensuring reliable performance and robust system availability. Thus, maintaining vendor support ensures the timely resolution of system incidents and minimizes the risk of system downtime, which allows business operations to proceed uninterrupted and maintains productivity.

In order to maintain these benefits and avoid reliability and cyber security risks, Toronto Hydro plans to upgrade its ERP system within the 2025-2029 rate period to a newer version that will retain current vendor support. A well-supported ERP system also aligns with the utility's strategic objectives as continuing vendor support enables the enhancement and adaptation of the system and the modernization of business processes in accordance with customers' evolving needs and broader industry trends such as electrification.

Given the criticality of the ERP system to Toronto Hydro's day-to-day operations, the maintenance of system reliability, and business continuity, the SAP ERP upgrade is necessary to support current and future business processes in an efficient and effective manner. To ensure an effective solution, the utility assessed four options as follows:

1. <u>Managed Deterioration</u>: Maintain status quo with the current SAP Enterprise Central Component (ECC) version;
2. <u>System Sustainment</u>: Execute required reactive work to keep the SAP ECC current without undertaking an upgrade;
3. <u>S/4 HANA Private Cloud (On-Prem)</u>: Upgrade to S/4 HANA, the next supported SAP ERP version and implement on-premises (i.e. on-prem) on private cloud; or
4. <u>S/4 HANA Public Cloud</u>: Adopt SAP's ERP solution on public cloud.

Toronto Hydro evaluated each option against three broad categories:

A) **Project Approach** – This category considered criteria such as expected project complexity, project costs, project timeline, and change impacts to the organization.

B) **Innovation** – This category evaluated each option in terms of contribution to productivity and efficiency, as well as alignment with Toronto Hydro's strategic objectives and outcomes.

C) **Maintenance** – This category evaluated the options from an operational perspective with respect to expected ongoing vendor sustainment costs, cyber security risks, and overall system reliability.

Toronto Hydro concluded through its options analysis that S/4 HANA Private Cloud (On-Prem) is the preferred option because of the stability it provides from a system reliability and maintenance perspective, and the potential flexibility it provides to help the utility improve efficiency and modernize its business processes in accordance with it's strategic objectives and outcomes. Under this option, Toronto Hydro will receive full vendor support until 2040. Although this option entails some project-related risks in the short term, the utility expects to mitigate these risks through appropriate planning and strong project governance.

Overall, the SAP ERP Upgrade project will:

- Reduce business continuity risks that may arise from system and infrastructure failures relating to the ERP system;
- Contribute to maintaining a robust cyber security posture;
- Build a foundation to support future process automation opportunities and associated productivity gains; and,
- Provide Toronto Hydro with greater flexibility to innovate and modernize its business processes in alignment with its strategic objectives and outcomes.

2 Problem / Opportunity Statement

2.1 Background

Toronto Hydro implemented the SAP ERP system on October 1, 2018. The SAP ERP system is a core Tier 1 IT system as it supports over 150 business processes in Toronto Hydro and impacts a large number of the utility's business units.

2.1.1 Application Components

Toronto Hydro's SAP ERP system is currently comprised of both cloud and on-premises modules.

The cloud modules include:

- SAP SuccessFactors: A solution that supports human resources (HR) processes such as recruiting, onboarding and offboarding, training, and performance management.
- SAP Ariba: A strategic sourcing suite that serves a variety of procurement functions such as sourcing (e.g. RFx)[1], contracting, and vendor spend analysis.
- SAP Concur: An expense management system to manage travel and business expenses.

The cloud modules are integrated with the on-premises modules and follow a subscription licensing model. SAP maintains and updates these systems as part of system lifecycle management. The SAP ERP system upgrade does not include upgrades to cloud modules.

The on-premises module, called Enterprise Central Component (ECC), includes the following components:

- Enterprise Asset Management (EAM): used for managing the financial lifecycle of the utility's assets.
- Record to Report (R2R): used to collect, process, and present financial data.
- Source to Procurement (S2P): enables integrated procurement processes such as purchase requisitions or purchase orders in SAP.
- Human Capital Management (HCM): integrates HR processes relating to payroll, time sheeting, and attendance, with financial systems.
- Warehouse Management System (WMS): enables warehouse management processes and integrates with procurement and financial processes.

[1] RFx is defined as request for any type of proposal including Request for Information (RFI), Request for Quotation (RFQ), Request for Proposal (RFP) and Request for Information (RFI) proposal.

These components follow the conventional perpetual licensing, support and maintenance model. The SAP ERP system upgrade will focus primarily on upgrading the on-premises module (i.e. ECC).

2.1.2 Application Integration

In addition to integrating with the previously discussed cloud modules, the on-premises SAP modules also integrate with many Tier 1 and Tier 2 IT systems. These business systems and their supported functions include:

Systems	Supported Business Functions
Asset Investment Planning	Distribution asset management processes
Emergency Callout System	Automated callout system used in disaster and emergency conditions
Customer Information System	Linking customer billing and accounts receivable processes to financial systems
Employee Health Benefits	Employee benefits management
Enterprise Data Warehouse	Reporting and analytics across various enterprise systems
Electronic Tailboard System	Tool for on-site safety risk assessments by field crews
Financial Institution of Record	Payroll processing, accounts payable and accounts receivable processes
Financial Reporting System	External reporting processes for financial disclosures
Vehicle GPS System	Fleet vehicles management
Labour Relations System	Business processes for employee and labour relations
Network Management System	Real-time network modelling used in distribution system operations
ERP Data Warehouse	ERP Reporting for SAP
Vendor Invoice Management System	Accounts payable processes

2.1.3 Infrastructure Components

The on-premises SAP modules are supported by a technology stack hosted in Toronto Hydro's Enterprise Data Centre. This infrastructure is comprised of the following:

- Server Infrastructure: The server infrastructure consists of both physical server hardware and virtual servers. This infrastructure relies on IBM infrastructure.

- Database Infrastructure: The database infrastructure supports the structured and unstructured data in the ERP System. The infrastructure is supported by an Oracle database farm.
- Middleware Infrastructure: The middleware infrastructure enables the integration between systems, and supports the movement of data. The two primary middleware components are the Websphere Application Integration Platform (AIP) and SAP Data Services.

2.2 Problem Statement

As previously discussed, the secure and reliable operation of the SAP ERP system is critical to Toronto Hydro's operations. Although the SAP ERP system is currently fully supported, SAP plans to terminate vendor support by 2027. Therefore, Toronto Hydro needs to maintain and upgrade the SAP ERP system and the underlying infrastructure to retain vendor support and continue receiving periodic service packs, patches, cyber security fixes, and technical support for product releases, incidents, or service requests. Current and active vendor support would ensure appropriate housekeeping and enable incremental maintenance and enhancements of the system. The following section discusses the risks that the utility may incur in the event that vendor support is lost and the condition of the SAP ERP system deteriorates without further upgrades.

2.2.1 System Risks: Infrastructure Lifecycle

While the current SAP ERP infrastructure is fully supported, the end of life for the current application servers and database servers is forecasted to be in the 2026–2027 timeframe. Beyond the SAP ERP system's end of life, Toronto Hydro would need to plan for contingencies that include sourcing hardware components from third party vendors. In extreme cases (e.g. system interruptions), the resolution of infrastructure issues might require applying solutions on a trial and error basis, greatly reducing the reliability of the solution and possibly prolonging system restoration times. In any case, without infrastructure upgrades significant risks of delayed recovery from system failure would arise and adversely impact business operations.

2.2.2 System Risks: Cyber Security

The SAP ERP system receives periodic service packs and patches from SAP. Occasionally, SAP also releases ad hoc security patches to address known critical security vulnerabilities. However, without vendor support, Toronto Hydro would lose access to these service packs and patches, which would increase the ERP system's exposure to cyber security threats and increase the risk to the utility.

2.2.3 Business Continuity Risks

Without upgrades and vendor support, when the SAP ERP system is past its end of life, Toronto Hydro may not be able to resolve system defects and incidents in a timely manner. As a result, business processes and functions would be adversely impacted resulting in a decrease in productivity and a reduction to the overall reliability of the system.

To address these challenges, the utility might have to implement manual workarounds, which may introduce significant operational inefficiencies resulting in lower service levels (i.e. longer processing times). In addition, the technical availability of vendor products or support (e.g. the compatibility of certain patches and security updates) in the future may be contingent upon Toronto Hydro upgrading its ERP system. In other words, if the utility were to defer system upgrades to the point where the existing systems and infrastructure are no longer compatible with new patches or products, it would need to find alternative mechanisms to execute its business processes until it upgrades its ERP system to the latest version. This exposes a number of critical business processes to operational inefficiencies, risk of failure, and could hinder day-to-day operations.

2.2.4 Process Automation and Innovation

In order to effectively respond to the evolution of customers' needs and expectations arising from emerging industry trends such as electrification and decarbonization, Toronto Hydro will need to invest in modernizing its business processes through process automation, innovation, and the adoption of industry best practices. An upgraded SAP ERP system will allow Toronto Hydro to adopt new business processes and streamline existing business processes with greater flexibility and speed.

At this point in the product lifecycle, SAP no longer provides any new functional enhancements to the ECC product functionality. If Toronto Hydro were to forego upgrades to a newer solution, it would be hampered from efficiently achieving the above goals, as it would no longer receive functional enhancements, improvements, and efficiency gains from the vendor. As a result, the utility may be severely constrained in customizing the current SAP ERP system, limiting Toronto Hydro's ability to flexibly adapt its business processes to the evolution of customers' needs and expectations as well as other industry trends.

3 Business Requirements Summary

The SAP ERP Upgrade is a transformational project that impacts various business processes across Toronto Hydro. This section provides a high-level summary of the functional (i.e. related to maintaining current system functionality) and technical (i.e. related to conformance with the utility's IT standards) requirements for the upgrade. A more detailed list of can be found in the Appendix to this Business Case.

3.1 Functional Requirements

Categories	Functional Requirement
Asset Plan Build Maintain Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Track, manage, and report the asset lifecycle - Include details for each phase of the asset lifecycle (e.g. cost elements, approvals, work assignments, projects, and maintenance associated with an asset) with consideration for data and workflows - Require data consistency across multiple divisions and understanding of detailed business processes to enable future cross-functional innovation opportunities
Customer Connections Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Serve customers' specific grid connection needs - Include the end to end workflow, data, and financial aspects across all connection process stages from design to construction and ultimately energization - Ensure effective communication with customers and facilitate financial transactions to better serve customers, and create opportunities for process improvement and efficiencies - Evaluate project estimates at a granular level, calculate accruals and net present value (NPV), and retain an audit trail of estimates with parameter changes, timestamps, and user name
Event Management Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Govern the interactions between field work and Control Centre processes from planning to execution including the procedural aspects as well as the underlying components - Ensures business process consistency as noted with the current SAP ERP system, including the different elements supporting field work, such as planning, costing, and engaging operationally with customers. - Support an efficient and effective event management process to serve customers

Human Capital Management Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Administer timekeeping and payroll processes - Ensure time entries and approvals are appropriately recorded and payroll is appropriately disbursed. - Maintain timekeeping processes and provide opportunities for continuous improvement. - Calculate different payroll components and produce the necessary payroll related artifacts and compliance reporting - House a number of workflows and complex rules to support time submissions that comply with collective agreements and legislative requirements - Prescribe the details for workflows, data, business and legislative rules, and reporting to support and govern these processes
Meter to Cash Pillar: Innovation Topic(s): Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Administer accounts receivable and payment receipts from customers - Administer rules for monthly interest, late payment charges, deposits, and record the correct transactions to Toronto Hydro's General Ledger (GL) - Elicit details of different workflows, data elements, approvals, and user roles to fulfill the Meter to Cash process - Support industry best practices associated with relevant document lifecycles and their management in the Meter to Cash process, including items such as job quotations, billing, etc. - Consistently execute the process in an efficient and effective manner by calculating the monthly interest due to customers for deposits and process bills for or refunds to customers for capital contributions and expansion deposits
Record to Report Pillar: Innovation Topic(s): User Experience Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Support key financial backend activities - Apply rules to support asset level transactions from the balance sheet perspective - Ensure asset costs are appropriately captured across the asset lifecycle - Enable accurate and detailed financial reporting through detailed workflows - Specify the necessary elements to capture financial transactions, apply stringent controls, consolidate the transactions across the organization, and accurately report them in accordance with applicable accounting, regulatory and financial guidelines

	- Accept summary values for billing and cash from the Customer Information System and define the schedule to close the inventory sub-ledger - Enhance end user experience - Ensure compliance with accounting, financial, and regulatory guidelines
Source to Pay <u>Pillar</u>: Innovation <u>Topic(s)</u>: User Experience Enablement <u>Pillar</u>: Maintenance <u>Topic(s)</u>: Vendor Support Control of Product Feature TH Releases	- Provide the framework for procurement activities like sourcing, contracts, inventory management and vendor management - Build on procurement policies and procedures and include the entire contract lifecycle - Configure spend approval workflows to efficiently manage the procurement process - Functional requirements will specify the details for these components to ensure the process in the system is comprehensive and runs effectively - Allow the system to meet procurement and payment guidelines, govern the procurement process and track vendor performance - Optimize the procurement process by increasing process efficiencies
Other Requirements <u>Pillar</u>: Innovation <u>Topic(s)</u>: User Experience <u>Pillar</u>: Maintenance <u>Topic(s)</u>: Vendor Support Control of Product Feature TH Releases	- Allow all attributes associated with the following data be appropriately ported over and verified: accounts payable, accounts receivable, journal entry, cost center accounting data, asset and equipment master data, functional location data, Work Breakdown Structure (WBS) and Internal Order (IO) data, material and vendor master data, purchase order, contract and project data - Allow users to book a vehicle and capture necessary user information. Present the user with vehicle attributes and apply business rules at the time of the booking - Continue to integrate with other core Toronto Hydro systems to ensure ongoing uninterrupted service

3.2 Technical Requirements

Categories	Technical Requirements
Infrastructure Components Pillar: Innovation Topic(s): Alignment with TH IT Standards User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases IT Reliability	- System infrastructure must adhere to Toronto Hydro's IT standards, including alignment with industry norms for optimal system performance and operations - Ensure the time between system loss and system recovery is minimized, and system downtime is reduced, ensuring business continuity
Cyber Security Pillar: Innovation Topic(s): Enablement Alignment with TH IT Standards User Experience Pillar: Maintenance Topic(s): Vendor Support Cyber Security Risks IT Reliability Control of Product Feature	- Adhere to Toronto Hydro's IT standards, including alignment with best practices related to user access to the system, data encryption within SAP, and appropriate security practices integrated with other systems - Allows users to view data corresponding to their respective roles and to execute their core functions

3.3 Assumptions & Dependencies

Toronto Hydro makes the following assumptions relating to the overall scope of this project:

- The SAP ECC lifecycle will not change.
- Toronto Hydro will not implement any new SAP modules within the current SAP ECC.
- The cloud modules SAP Ariba, SAP SuccessFactors, and SAP Concur will persist until the SAP ERP Upgrade concludes.
- Existing integrations to the SAP ECC will remain intact until the SAP ERP Upgrade concludes.
- No new and major technological developments that impact SAP ECC and its underlying infrastructure will emerge.
- SAP's S/4 HANA product, services and licensing will not deviate from the current state.
- There will be no new and major changes to functional and/or technical requirements.

- There will be no change in organizational direction relating to the overall project approach described in this Business Case document.

Any change in the assumptions listed above, will require a reassessment of the project scope, timelines, and costs.

4 Options Analysis and Recommendation

Toronto Hydro evaluated a number of options to address the risks and challenges discussed above in Section Two and engaged various internal and external stakeholders to determine the optimal solution.

As a starting point, Toronto Hydro reviewed the current state functional and technical requirements that the SAP ERP system fulfills and the system's footprint against the utility's Information Technology Investment Strategy.[2]

Toronto Hydro also considered available options in terms of their alignment with the utility's strategic objectives and outcomes for the 2025-2029 rate period, and specifically whether individual options would provide sufficient flexibility in modernizing business processes by enabling enhancements to the SAP ERP system.

This exercise helped Toronto Hydro identify and assess the four options that are discussed in greater detail below.

4.1 Options Analysis

Option 1 - Managed Deterioration

Under this option, Toronto Hydro would not upgrade the SAP ERP system's current infrastructure and applications. Due to the several drawbacks discussed below, the utility has not selected this option.

Maintaining current assets in operational condition under this option would require Toronto Hydro to purchase extended support for the infrastructure and the application at a premium. Although extended support by the vendor would provide the technical resources to troubleshoot incidents, incident resolutions would not be guaranteed. Purchasing extended support would increase the utility's operational costs and vendors typically provide this type of support only on a best efforts basis. Therefore, if an incident or failure were to compromise the integrity of the ERP system, Toronto Hydro and its vendor likely could not effectively remediate the issue, which may significantly and adversely impact distribution operations and financial reporting. These impacts potentially could be so severe as to affect the utility's financial viability, e.g. by rendering it unable to pay its employees and vendors. As such, this option would pose high operational and financial risks.

This option would also significantly increase cyber security risks. As an application ages, the code and communication standards used by it become outdated, making the application more vulnerable to cyber security threats. Toronto Hydro would be severely constrained in its ability to

[2] Exhibit 2B, Seciton D8 – Information Technology (IT) Investment Strategy

mitigate this risk, and any efforts to mitigate this risk may compromise other functions. For example, the utility may be unable to modify the SAP ERP system to the extent that any customizations would adversely impact system performance and efficiency. Alternatively, if customizations by the utility are not supported by SAP, Toronto Hydro would run the risk of voiding its support contract with SAP, leaving the aging system even more vulnerable to cyber security threats without comprehensive vendor support.

Furthermore, finding the technical resources to support legacy applications is challenging. As the resources that are qualified to support SAP are currently focusing on updating their skillsets for S/4 HANA, the industry pool of resources available to Toronto Hydro to implement this option would significantly shrink in the near future and as a result, the utility may not be able to address this gap.

Finally, this option would not allow Toronto Hydro to enhance its business processes through automation and innovation, and by extension, respond effectively to changes in customers' needs and expectations due to future industry trends such as electrification and decarbonization. Continuing to work with the legacy version of the SAP ERP system would prevent the utility from accessing new enhancements and technological developments, and thus severely curtail its ability and flexibility in modernizing its services or underlying business processes. Therefore, this option does not align with Toronto Hydro's strategic objectives and outcomes.

Option 2 - System Sustainment

Under this option, Toronto Hydro would implement only the minimally necessary upgrades to the SAP ERP system's underlying infrastructure components in the 2025 – 2029 rate period. The application would not receive any upgrades or any new features or functionality beyond 2027 (i.e. the end of vendor support). Although the risk profile of this option would be somewhat more moderate compared to Option 1, it would also represent significant lost opportunities for Toronto Hydro, as the utility would not be able to leverage new enhancements and technological developments from more comprehensive system upgrades to modernize its services and underlying business processes in response to changes in customers' needs and expectations due to future industry trends such as electrification and decarbonization.

Similar to Option 1, maintaining current assets in operational condition under this option would require the utility to purchase extended support at a premium. Although extended support by the vendor would provide the technical resources to troubleshoot incidents, incident resolutions would not be guaranteed. Purchasing extended support would increase the utility's operational costs and furthermore, vendors typically provide this type of support only on a best efforts basis. Therefore, if an incident or failure were to compromise the integrity of the ERP system, Toronto Hydro and/or its vendor likely could not effectively remediate the issue, which may significantly and adversely impact distribution operations and financial reporting. These impacts potential could be so severe as to affect the utility's financial viability, e.g. by rendering it unable to pay its employees and vendors. As such, this option would pose high operational and financial risks.

This option would mitigate cyber security risks to a limited extent. Under the extended support, the applications and underlying infrastructure would continue receiving vendor security patches; however, there would be no guarantee that these security patches could fully mitigate all types of cyber security threats encountered today and in the future.

It is highly likely that Toronto Hydro will need to upgrade the SAP ERP system's underlying infrastructure in the 2025 – 2029 time period. However, it is possible that the renewed infrastructure might not be fully compatible with the current SAP ECC version, which would require the utility to rely on manual workarounds to ensure the continuity of business processes, consequently decreasing the efficiency of such processes. In any case, Toronto Hydro likely would have to invest in upgrading to the latest version of the SAP product and migrating the HANA database at some point, as the benefits of the new infrastructure would not be fully realized until Toronto Hydro migrates to the new SAP system. Because this option would not fully address the previously discussed issues and drive further investments in the future, it ranks poorly in terms of cost effectiveness.

Although this option would allow Toronto Hydro to modernize its business processes through automation and innovation to a limited extent, the value received from related investments likely would not be optimized, as the utility would have to make further upgrades in the near term, before the end of life of the newly implemented assets. In addition, this option may require Toronto Hydro to procure and operate a number of outdated peripheral systems to continue to innovate.

Option 3 - S/4 HANA Private Cloud (On-Prem) – Recommended Option:

Under this option, Toronto Hydro would implement the S/4 HANA (On-Prem) solution, which is the latest available version of the SAP ERP system. It would embed the latest software, code, security, and communication standards, which would also align with the utility's IT standards. This option will mitigate cybersecurity risks for both, the applications and underlying infrastructure by ensuring a robust cybersecurity posture through continued access to vendor security patches.

To implement this option, Toronto Hydro would purchase private cloud licenses to install the application on its infrastructure in its on-premises Enterprise Data Centre. The application would be configured to enable existing business processes in the system. This may require incremental changes to some existing business processes which would result in some change management risk. This option would allow the utility to flexibly control the maintenance windows for the SAP application and infrastructure based on organizational needs. Furthermore, Toronto Hydro would be able to evaluate new product releases based on new functionalities, validate them against existing and future business needs, and determine the appropriate time to implement the new functionality.

By upgrading to the latest version of the SAP solution, Toronto Hydro would have access to a large resource pool of technical and functional resources whose skillsets would evolve to include HANA in the next few years. This would ensure that the utility is able to operate and maintain its ERP system in a much more cost-effective way and without having to depend on technical resources to support and sustain a legacy system.

SAP will fully support the S/4 HANA application until 2040. The SAP ERP Upgrade will mitigate business continuity risks by ensuring high system availability and full vendor support to resolve any issues in a timely and effective manner. Toronto Hydro would also have the option to implement periodic enhancement packs based on the desired benefits. This flexibility would support the utility's modernization of business processes through automation, innovation, and integration with other applications and systems. Thus, Toronto Hydro could adapt its services and underlying business processes much more easily and at an optimal cost in response to changes in customers' needs and expectations due to future industry trends such as electrification and decarbonization.

Option 4 –S/4 HANA Public Cloud

Under this option, Toronto Hydro would implement SAP's S/4 HANA public cloud solution, which is a software-as-a service (SaaS) application. Although this solution would also have the latest features and releases, the utility anticipates that the available configurations would not align with its business practices. As such, Toronto Hydro would need to adapt its existing business processes to work in tandem with the functionality of the S/4 HANA public cloud application, which may result in inefficiencies and generate additional change management costs. For example, the utility might need to update its job quotation templates to adhere to the standard formatting used in the S/4 HANA public cloud.

This option would pose significant change management risks, as the vendor might release new features and functionalities to users with limited or no ability to modify them to meet business requirements. Thus, redesigning business processes to conform to the evolution of the ERP system would require considerable efforts and time to implement, plan, and manage changes, and retrain employees accordingly.

Under this option, Toronto Hydro would have very limited direct control of the application and some application components would not be configurable or customizable. For example, the utility uses SAP for timekeeping and the current solution caters to different employee types and their associated rules and workflows. By contrast, the public cloud option might not be able to fulfill all functional and business requirements. Consequently, Toronto Hydro may need to resort to a number of manual procedures to fully meet such requirements. Effectively, the utility would be dependent on its vendor(s), namely the cloud infrastructure provider and the application host, who would determine at their sole discretion release schedules and service elements. In order to meet the vendor timelines and release schedules, Toronto Hydro might need to reallocate resources from other areas to ensure that testing is completed on time. This lack of control over downtime hours and maintenance windows could present a major risk to the utility's ability to restore outages and respond to major events in a timely and effective manner. Therefore, this option would introduce significant operational and business continuity risks.

SAP will fully support the S/4 HANA application until 2040. Toronto Hydro would have the option to implement periodically released enhancement packs based on the desired benefits. Access to such enhancements would support the utility's modernization of business processes through automation and innovation to a limited extent. However, these benefits would be likely offset by the need to deploy extensive resources to ensure integration with other applications and systems and redesign business processes to conform to the vendor-led evolution of the ERP system.

4.2 Evaluation Criteria

Toronto Hydro evaluated each option based on the following criteria:

A) The **Project Approach** category includes the different factors in executing a project such as:

- Project complexity (e.g. challenges in project design and technical details, end user impact and associated risk);
- Project costs (e.g. planning, design, implementation costs);
- Project timelines (project task start and end dates); and,
- Change Management (implementation of a single new technology, or an overall digital transformation overhaul, adapting to market changes, launching new products)

B) The **Innovation** category considers how the ERP technology fosters business process improvements, increases the velocity of business processes, enables future organizational transformation, and provides more meaningful information to the end user for sound business decisions. It ensures the project's alignment of:

- SAP technology landscape against Toronto Hydro's IT standards; and,
- Toronto Hydro's strategic objectives and outcomes, overall industry trends, and future improvement opportunities, in accordance with the IT Investment Strategy.

C) The **Maintenance** category evaluates day to day operations from the perspective of ongoing system operability, including the ability to respond to system issues and incidents, and the sustainability of business operations. The relevant factors under this category are:

- Cyber Security – which includes protection from cyber threats against the integrity and operation of the distribution system and the confidentiality of customers' and employees' personal information;

- Flexibility in System Maintenance Windows - to ensure business continuity under all operating scenarios, including critical storm events and high volume outage events; and,
- Toronto Hydro's control of the end-use product to ensure minimal disruption from system changes.

High Level Options Comparison

A high-level comparison of the options is provided in the table below.

Table 1: Options Comparison

Options	**Project Approach**				**Innovation**			**Maintenance**			
	Project Complexity	Project Costs	Project Timeline	TH Change Management	Enablement	Alignment with TH IT Standards	User Experience	Vendor Support	Cyber Security Risks	IT Reliability	Control of Product Feature TH Releases
1. Managed Deterioration											
2. System Sustainment											
3. S/4 HANA Private Cloud (On-Premise)											
4. S/4 HANA Public Cloud											

Legend	Exceed Criteria	Meets Criteria	Partially Meets Criteria	Does Not Meet Criteria

4.3 Evaluation Summary and Recommendation

Comparing all of the options presented in the preceding sections, Toronto Hydro recommends Option 3, the S/4HANA Private Cloud (On-Prem) solution for the 2025–2029 rate period as it poses the least amount of overall risk and provides the greatest benefits across all three categories of project approach, innovation, and maintenance. Specifically, the benefits of the S/4 Hana Private Cloud (On-Prem) solution include a customized system that provides enhanced capabilities to process data and execute business functions, and ongoing vendor support.

Although there are increased project risks associated with implementing a new system, these risks can be mitigated though a robust project governance structure.

With respect to the project approach criteria, the Managed Deterioration and System Sustainment options rank the highest. Both options maintain the status quo to differing degrees and involve a limited level of investment in new products or initiatives, and thus have little to no impact on the end-user experience. As a result, both options result in a relatively low risk with respect to the overall project scope, timelines, and costs. However, in the long-term, both options would require Toronto Hydro to upgrade its SAP ERP system beyond 2030, therefore introducing inherent maintenance risks that are further elaborated on below. The S/4 HANA Public Cloud option ranks the lowest with respect to project approach criteria. This option provides little to no customization alternatives to the utility, and requires the project to expend resources to conform Toronto Hydro’s current processes and functional requirements to the vendor-supplied solution. As such, there is a high risk that the project outcome could result in process inefficiencies in business operations, increase the costs of executing business processes, and limit the development of a more effective system. With respect to project approach criteria, the S/4 HANA Private Cloud (On-Prem) option ranks higher than the S/4 Public Cloud option. This option has higher costs than the Managed Deterioration and System Sustainment options as a full system upgrade is required, and this includes re-establishing existing business processes on the new ERP system. However, this option leads to lower overall risk through greater control over configuration and customizations, and limited impacts to existing business processes thereby reducing the organizational and change management risk. While there are some increased project complexity risks due to implementation of these new functionalities, these risks can be mitigated through a robust project governance structure.

With respect to the innovation criteria, the S/4 HANA Private Cloud (On-Prem) option would rank the highest as it would enable the utility to establish a modern platform with enhanced capabilities to process data and efficiently execute business processes. This option would take full advantage of product enhancements and new technologies, and would enable further modernization and business transformation. By contrast, the Managed Deterioration and System Sustainment options rank the lowest as both options would retain the current SAP ERP version. As a result, they would provide fewer opportunities for Toronto Hydro to improve business processes, enable future business transformation, and enhance the end-user experience. Both options would involve retaining outdated back-end infrastructure that would be unable to support new data processing capabilities and would result in the deterioration of the end-user experience. While the S/4 HANA Public Cloud option would rank higher than the Managed Deterioration and System Sustainment options with respect to innovation, this option would only allow for modernization within the confines of the vendor-supplied solution. Therefore, it would pose a risk of misalignment between Toronto Hydro’s strategic objectives and the vendor’s product roadmap. This would impact the effectiveness and pace of the utility's ability to implement system changes and modernize its business processes in response to future industry challenges.

Lastly, under the Maintenance criteria, S/4 HANA Private Cloud (On-Prem) option ranks the highest, as it ensures ongoing vendor support, greater control over feature releases and the timing of those feature releases. The Managed Deterioration and System Sustainment options would rank the lowest. Both options would retain the current infrastructure, which would likely limit vendor support to a best effort basis and would not benefit from security updates to mitigate cyber threats to the SAP ERP system. S/4 HANA Public Cloud ranks higher than the Managed Deterioration and System Sustainment options with respect to Maintenance criteria. Under this option, the utility's dependence on its vendor(s) would give rise to several risks related to business continuity (e.g. in securing support from vendor resources in a timely fashion during emergencies) and risks with respect to the timing and flexibility of product releases if the utility were to require a rescheduling to account for unforeseen circumstances.

4.4 Estimated Project Timelines and Costs

Estimated Project Delivery Duration: 24 months

Estimated Capital Expenditure Breakdown:

Group	Description	Costs ($M)
Internal labor (IT and business resources, stream leads, etc.)	Toronto Hydro full-time employees assigned to the project from initiation, blueprinting, build and launch to closure	$ 4.7
Contractors	Third party specialist resources onboarded with specific S/4 HANA project skillsets to augment the Toronto Hydro team	$ 3.8
Licences	IT software costs for using the new S/4 HANA Private Cloud (On-Premises) ERP system	$ 4.5
Hardware	IT infrastructure to support the new and upgraded S/4 HANA ERP system IT infrastructure to execute the backend system processes as per specifications	$ 3.0
Vendors (S/4 Upgrade System Integrator, other specialized vendors)	Vendor identified to implement the project from initiation, blueprinting, build and launch to closure	$ 12.0
Total		**$ 28.0**

Estimated Project Operational Expenditure:

Group	Description	Costs ($M)
Data Migration	Migrate data from the current SAP ECC system Complete necessary data migration checks Ensure continuity in business processes	$ 0.5
Training and Change Management	Train employees in the new S/4 HANA system Engage and educate employees of system changes and business process changes	$ 0.5
Post Go-Live Support	Hand-off technical and functional aspects of the project to the appropriate Toronto Hydro resources Ensure business processes are functioning as expected and address any user queries	$ 0.6
Total		**$ 1.6**

5 Appendix

The SAP ERP Upgrade is a transformational project and impacts a large number of Toronto Hydro's business units. The requirements presented in this Business Case consider the following:

- Functional Requirements: Maintain current system functionality to support business processes
- Technical Requirements: Consider new technology trends consistent with Toronto Hydro standards

5.1 Functional Requirements

Categories	Functional Requirement

Asset Plan Build Maintain
 	
Pillar: Innovation
Topic(s):
Enablement
User Experience
 	
Pillar: Maintenance
Topic(s):
Vendor Support
Control of Product Feature
TH Releases
	• The system should allow creation of Work Orders (WOs) and populate an estimate of Maintenance Work
	• The system must capture:
	  ○ schedule constraints such as vacation, training and feeder planned outages
	  ○ crew capabilities,
	  ○ vehicle / equipment usage
	  and build an overarching plan with some rules to accommodate corrective deficiency notifications
	• The system must assist building a schedule with a framework for users to cater to their specific needs, and track progress against the plan based on schedule and financials
	• The system should assign work orders to inspection work and allow users to assign inspectors to work orders
	• The system should record the overall goal of the scope item with linkages between the scope package and the regulatory filing, and ensure appropriate approvals are secured within a workflow
	• The system must allow user to create a maintenance plan for any asset level through work orders and apply some business rules for those assets due for replacement as part of the capital program
	• The system should process change requests and capture detailed material, labour, and assets required with a view of the impact to the master schedule and secure approvals via workflows
	• The system should assist program planning activities in a consistent project structure across different time horizons and consider resources, materials and costs calendarized over the life of the program with reporting capabilities

	• The system must identify failed assets from planned and reactive work orders with outage / event information and provide a higher-level asset class view to view system issues • The system should allow accruals to a Work Order when an invoice is requested and allow invoice submission based on service entry sheets linked to Work Orders • The system must allow the assignment of Work Breakdown Structure (WBS) to the project development team and assignment of the team costs to the WBS • The system, across applicable business units, must allow sign-off and attainment on receipt of the Green Construction Folder with linkages to the design hours and updated assets • The system must allow the user to close out a design project after the pre-requisites are met and must allow the project to be put on a construction schedule • The system must allow for long terms planning using conditions by asset class and receiving key data measures from other systems to build the scope definition, complete data analysis and to study impact analysis • The system must capture units of work in hours, units of assets, notes and view materials for project planning and reporting purposes • The system must define work packages, relate them to investments, assets, similar and adjoining projects, and use workflows for approvals • The system must track the work package from design to execution with risks defined from a Master List and allow to report on progress • The system will allow users to build the project structure with templates containing breakdown structures and pre-populated data and allow the flexibility to tweak the project structure as needed • The system must allow user to build estimates using applicable methods (e.g. asset assemblies, unit price methods), maintain versions, view design costs and actuals and secure approvals through workflows • The system must record and report construction work completed against a plan line in terms of asset assemblies and schedules • The system must allow users to build packages estimates based on applicable frameworks (e.g. asset assemblies, unit price methods), and summarize the resource and asset needs using Future State data and guided by Historical Trends • The system must allow the user to assign a risk score at the scope, project level and support scenario planning with appropriate versioning • The system must allow the user to issue materials against a work order while applying appropriate checks for quantities and secure approvals in case of exceptions

	The system must capture details when an asset is energized with planned versus actual details of Order to Operate (OTO) and Planned Outage information • The system must retain a record of the assets and their conditions, by location, by asset and by hazard to predict the financial risk and the reactive capital expenditure spend • The system must correlate current feeder loading information, future state studies and estimates from external tools to determine future load • The system must be able to use datasets in the Maintenance Investment Model to identify assets for renewal and perform what-if analysis • The system must allow work assignment to specific Designated Responsible Person (DRPs) with notifications and include in the assignment details on dates, required assets and ability to view progress • The system must allow a Program Manager to assign design projects to specific Project Managers and assign detailed estimates to be completed, and track the time required to complete the work • The system must allow cash flow for the various planning cycles and scenarios and allow carry forward opening balances to the next fiscal year • The system must allow identification of inspection tasks in work orders and the ability to submit inspections after necessary changes and report on the aggregate work completed
Customer Connections Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system should provide a workflow to calculate the Net Present Value (NPV) and provide form templates to support user requests for NPV calculations • The system must auto-populate the Offer to Connect (OTC) form with Toronto Hydro's account number in the event customer sends funds via Electronic Funds Transfer (EFT) • The system should allow designers to create a job quotation and secure necessary approvals using a system-based workflow • The system should manage a feeder load request process that considers the work assignment, feeder hierarchy, asset data, costs and basic power flow analysis • The system must evaluate project estimates and accruals at a granular level, calculate NPV, retain an audit trail of estimates with parameter changes, timestamps, and user name
Event Management Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance	• The system must provide the ability to record and release Confined Space Hold Off requests against a work order • The system must gather claims data along with the ability to store files and notify when payment is due

Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must allow work orders to capture time, over-time, cost, materials, notes and link work orders together with ability to report on work orders completed • The system must allow for options to share electronic content within Toronto Hydro and with vendors, customers and the City of Toronto • The system must allow user to schedule planned reactive and planned work orders against crew (vehicle, labour, and time) capacity, and skills • The system must generate reports to view the daily, weekly, and monthly performance of planned and unplanned events by crew • The system must allow the crew to record field work completed, with details on OTO, notes, materials, tools, and equipment needed, and assign notifications, delivery dates and follow up work • The system must allow the user to define and assign forestry work to specific crews, prioritize the jobs and allow the assignee to report back on progress • The system must allow multiple planned work notifications to be scheduled and issued to crews piecemeal with consideration for priority for any unplanned work and for follow up work
Human Capital Management Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must pre-populate employee timesheets with schedule and approved absences and must trigger appropriate workflows and notification on submission of timesheets and capture comments, where appropriate • The system must allow consideration and functionality for overtime pre-approval, employee hierarchy for approvals, emergency declaration and exceptions for timesheet submission, per terms of employment and basic timesheet rules • The system must integrate with SAP Concur and map the appropriate general ledger accounts with SAP Concur • The system should process payroll based on the timekeeping records for the pay period and consider the pay codes, tax implications and garnishments, including the retirees, non-Toronto Hydro employees per the applicable business rules
Meter to Cash Pillar: Innovation Topic(s): Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must calculate the monthly interest due to customers for deposits and process bills or refund customers for the expansion deposits • The system must accept billing financial transactions from Customer Information System and General Ledger (GL) interface and make the necessary adjustments in the GL • The system should calculate the late payment charge for customer accounts and keep a record of applicable late charge rates • The system must apply customer EFT and cheque payments to an invoice and process customer refunds

	• The system should estimate and prepare the bill for customer demand work with consideration for taxes
Record to Report Pillar: Innovation Topic(s): User Experience Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must allow for General Ledger account analysis that supports comments, workflows, attachments • The system must enable deposits against projects with capital contributions and link them to assets and project WBS. • The system must complete calculations to support capital contributions, costs (life to date), deposit balance • The system must generate reports to recognize excess key finances such as excess capital, deferred revenue, contributions realized, deposits, as they pertain to projects and reporting periods • The system must allow user to define Asset Retirement Obligation (ARO) assets with linkages to asset categories and sub-ledgers and support calculation of liability with reports as they pertain to capitalization and derecognition or decommissioning • The system must store and report on Accounts Receivable aging by customer class and groups with trends of balances, revenue and cash flow • The system must have workflows with approvals for elimination and consolidation transactions for journal entries and balances, and report on them • The system must maintain Fixed Asset Continuity and support reports for deferral accounts, regulatory balances, tax assets and liabilities, variances, expenses and recovery • The system must maintain Other Post Employment Benefits (OPEB) liability with opening balance and end liability with expenses, benefits and adjustments, including reports to support analysis • The system must have a template to pole removal that ties to WBSs, accruals, actuals and estimates, that allows for transactions and supports reports for analysis • The system must be able to build a "Road Cut" template to capture specifications from accruals, receipting and invoicing, City Permits and other processes • The system must enable the quarterly schedule of unreconciled differences (SUDs) process with appropriate workflows and audit checks, and reporting capability • The system must support the Allowance for Funds Used During Construction (AFUDC) rules and AFUDC process for projects and support the reports to govern the AFUDC process • The system should manage the end to end debt issuance lifecycle with key inputs and calculations from a tax standpoint and allow for reports to ensure governance

	• The system should estimate preliminary distribution revenue based on rates and regulatory assumption, estimate medium and longer term debt rates, and estimate operational and maintenance expense. • The system must calculate and report on eligible capital expenditures for capital contributions and tax related expenditures such as Capital Cost Allowance (CCA) • The system must provide the ability to calculate effective tax rate. • The system should estimate and allocate corporate shared services based on a number of parameters such as number of purchase orders (POs), payroll, occupancy and provide the option to manually adjust the estimates • The system should track and report the asset lifecycle from procurement to installation to retirement for all asset ty pes including the associated financials records for assets, labour and equipment • The system must identify major assets and support their capitalization while considering the project cost structure • The system must enable asset retirement obligation (ARO) functionality and reporting with calculation of associated liability, discount rate and cost allocations and assess the impact from changes to underlying rates and adjustments • The solution should accept summary values for billing and cash from the Customer Information System and define the schedule to close the inventory sub-ledger • The system must allow a user to build a forecast from existing plans, while maintaining version and applying standard allocation and distribution business rules, and secure the necessary approvals • The system must provide reports that compare actuals versus plan versus historical trends with supporting narrative comments for variances and provide the user multiple views of the data • The system must provide the ability to perform a depreciation simulation with capital contribution amortization, including software and leased assets, and issue exception reports • The solution should track and report the asset lifecycle when it is removed against the plan, and consider the impact to the general ledger accounts, capital contribution, and depreciated derecognition value, as needed • The system must have the ability to record the proceeds of disposition of specific assets and account for downstream effects to the relevant account codes, general ledger code and tax • The system must use data from the Customer Information System billing data interface to update the revenue / cost of power general ledger accounts at a customer class level and allow for reporting to validate the accuracy and completeness

	• The system must maintain a separate tax ledger and allow workflows to track documents, adjustments, approvals and reviews. The system must generate reports to support the process • The system must enable reporting of services, goods and invoices that did not charge harmonized sales tax (HST) • The system must provide the ability to produce internal & external financial statements including but not limited to balance sheets, statement of income, statement of comprehensive income, statement of change in equity, statement of cash flows and summary financial information (ratios) with financial data • The system must support the integration with Workiva (i.e. a financial external reporting system) to enable automation for external reporting • The system must allow setup and reporting of deferral accounts to support Ontario Energy Board (OEB) reporting requirements • The system must allow intercompany invoicing, settlements, transactions journal entries, asset transfers and interests administered through workflows to secure necessary and appropriate approvals • The system must provide the daily cash position based on integration with data from Customer Information System, bank information and build a forecast considering business rules on accounts receivable (AR) and accounts payable (AP) parameters • The system should provide the ability to centralize the operational and capital budgeting process through all stages, allowing for multiple iterations • The system must provide the ability to process property tax payable for each Toronto Hydro property in installments per the City of Toronto invoice • The system must be able to identify and estimate the tax treatment based on the location of the supplier, type of service, and location where service was provided, and provide applicable reports • The system must provide the ability to pay provincial payment in lieu of property tax in installments and be able to estimate the first installment payment • The system must incorporate closing (actual) gross fixed assets, undepreciated capital cost (UCC) and accumulated depreciation into the planning process and allow to run different scenarios for tax and financial purposes • The system should be able to calculate and forecast liability by ARO category using inflation rate, discount rate, accretion, payments and adjustment and use budgeted payments to lower liability • The system must allow to account for the following variables in the calculation of electricity revenue for the planning model: cost of power, retailer settlement variance account, rate riders

	• The system must capture and consolidate quantity, vintage and functional locations / region of assets by class to be decommissioned by each business unit, such that each asset is identified and asset quantity is adjusted accordingly • The system should calculate planned HST by month from net income, gross revenue and operational expenditure & capital expenditure numbers entered by the planning team and secure approval via a workflow prior to posting • The system should allow manual or calculated input of pre-capitalized inventory to book the change in pre-capitalized balance • The system should identify the property and estimate future property tax and secure necessary approvals prior to posting • The system must cascade impact from disposition of assets to ARO, capital contribution, revenue recognition of capital contribution • The system must be able to determine the value at cost of meters and transformers held in inventory • The solution must provide the ability to identify all regulatory deferral account (RDA) accounts by category, by nature and by regulatory status and calculate the change from the prior period and apply the changes against specific profit and loss (P&L) accounts, and provide reports to support analysis • The system should transact in multiple currency and revalue balance sheet accounts and maintain foreign exchange (FX) rate in Canadian dollars • The system must download detailed bank transactions and apply them gains GL bank transactions and interface Customer Information System cash receipts to the SAP GL • The system should identify contracts with pre-paid conditions subject to business rules associated with PO, contract, renewals, receipting etc. • The system must apply industry standards to the creation, modification, deletion, backup, restore and other such operations to financial data, records, artefacts and transactions • The system must identify and report, for City of Toronto and its affiliates as vendors or customers, with respect to deposits, payments, accruals, journal entries, revenue, capital contributions etc. • The system must produce reports on Canadian Electricity Association (CEA), total payment to governments, OEB's recordkeeping and reporting requirements, annual statistics Canada, capital expenditure and financial information • The system must support the calculation of a number of key financial metrics on costs, revenue, expenses, rate of return and interest rates to enable strategic planning

	• The system must allow for transfer of assets with the necessary approvals, retain traceability, move the depreciation with the assets and allow for asset re-evaluations
Source to Pay <u>Pillar</u>: Innovation <u>Topic(s)</u>: User Experience Enablement <u>Pillar</u>: Maintenance <u>Topic(s)</u>: Vendor Support Control of Product Feature TH Releases	• The system must capture detailed information on accruals, invoicing, ledgers, sub-ledgers, operating lease information, goods and services receipted in terms of suppliers, dates, responsibility center (RC), accountant, and district, dates • The user must be able to easily fetch reports to support the month and quarter end analysis with filters such as aging, thresholds, systems (e.g. Customer Information System), Independent Electricity System Operator (IESO) advancements, and to provide a longer term multi-year outlook • The system must allow an authorized user to create and modify POs, PO lines, the approved purchase spend, deliver address and dates with comments and version changes • The system must determine and calculate Engineering and Administration Reclassifications (EAR) eligbility and allow allocation to projects. The system must support reporting of EAR, such as allocation percentage • The system must enable end to end vehicle maintenance, with building plans, modifying them, taking into account skillset, demand and forecasts and reporting • The system must enable the equipment failure tracking process with creation of logs of failure that include time stamps, locations, equipment data, warranties and supporting documentation • The system must provide reports to compare plan vs forecast vs actuals with attributes such as RC, vendors, notes etc. and bring aging inventory and other materials into the forecast • The system must capture vehicle master records, maintenance plans, vehicle parts and maintenance plans, correlate charges against maintenance plans and issue invoices as needed • The system must link a contract to its upstream activity and capture key contract details, electronic signatures, attach POs to the contract • The system must generate a PO for inventory and non-inventory items with linkages to the underlying contract / request for proposal / request for quote / Request for Information (RFX) and report on PO aging and amount remaining on contracts • The system must allow a user to book a vehicle and capture necessary user information. The user must be presented with vehicle attributes and business rules must be applied at the time of the booking • The system must allow the process to decommission vehicles with appropriate inspection submissions and WBSs / IOs

	• The system must allow inventory to be defined by a number of attributes, such as source, lead times, and package details, to manage effectively and to allow complete individual and bulk updates across a number of inventory attributes • The system must allow creation of sales orders, delivery notes and invoices for the sale of scrap material and administering the disposal of other material such as vehicles. • The system must receive an extract of the transactions from the vending machines with transfer of costs to the appropriate charge code and vendor cost administration • The system must provide a framework to capture and manage the vehicle assignment and vehicle collection process • The system must provide a framework to accept vehicle return, administer the inspection, and, lastly, ensure charges are applied against the correct work order • The system must allow users to create / update / delete / define business partners with the appropriate approvals and authorization • The system must allow users with appropriate authorization to define and organize master data with ability to search fields and complete bulk updates • The system must provide the ability to populate vendor scorecard templates with metrics on exceptions, issues, transactions and overall data. • The system must allow for payment of invoices with and without POs applying three way matching where applicable subject to a tolerance factor, facilitate discounts and non-payment when needed, and eliminate risk of duplicate payments • The system must manage debit, credit memo, and update cheque and vendor records based on bank files • The system must allow the administration of holdbacks per the terms in the PO and ensure appropriate approvals and reasons are secured prior to applying the holdback and releasing payment • The system must allow the user to request vehicle maintenance and receive a notification on completion of the work order with start and end times • The system must have the ability to view reservations in terms of forecast, planned and actuals for the different vehicle categories, estimate the depreciated or lease value and ensure appropriate approvals are secured in case of purchase and sale and generate reports for analysis • The system should build a schedule of assets and assist with receipting them. The system should also provide some indicators of the process health and opportunities to flag exceptions

	• The system must prevent double receipting and potential double payment, and it must allow to drop shipped assets directly on site through inventory and non-inventory conversion • The system must allow creation of purchase requisitions consistent with Toronto Hydro's Procurement Policy with the ability to assign it to a vendor, RFQ or RFP process, leverage appropriate workflows to capture approvals and report on key metrics and health of the process • The system must allow the transmission and receipt of electronic documentation with electronic confirmation • The system must enable Ariba to perform RFX related activities and provide necessary organization information to govern the process • The system must enable centralized vendor setup with minimum required information by specific roles and setup must take into account standard terms and those unique to the vendor • The system must report on Key Performance Indicators (KPIs) to monitor performance for the following functions: fleet uptime, facilities response to tickets, warehouse, supply chain • The system must support analytics including spend consolidation opportunities, spend history with ability to drill down into details, view upcoming contract renewals and flag entries that could breach policy • The system must provide the ability to capture any invoiced costs associated with a return order including but not limited to assessment, shipping, refurbishment and warranty costs
Other Requirements Pillar: Innovation Topic(s): User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must allow all the attributes associated with the following data to be appropriately ported over and verified: accounts payable, accounts receivable, journal entry, cost center accounting data, asset and equipment master data, functional location data, WBS and internal order (IO) data, material and vendor master data, purchase order, contract and project data • The system must continue to integrate with other systems such as Customer Information System, Intelex, Remedy, and Royal Bank of Canada to ensure ongoing uninterrupted service • The system should support the industry best practices associated with the document lifecycle and its management in the Meter to Cash process. This would include items such as, quotations, billing, etc.

5.2 Technical Requirements

To address the business requirements, the new S/4 HANA system will need to adhere to the technical requirements below:

Categories	Technical Requirements
Infrastructure Components Pillar: Innovation Topic(s): Alignment with Toronto Hydro's IT Standards User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases IT Reliability	• The system must meet Tier 1 Service Level Agreements (SLA). • The system must have high availability with an uptime of 99.95 percent and targeted Return Time Objective (RTO) of equal or less than 4 hours and targeted Return Point Objective (RPO) of up to 4 hours of data loss • The infrastructure must adhere to the applicable Toronto Hydro standard for server, Storage Area Network (SAN), backup, database and middleware
Cyber Security Pillar: Innovation Topic(s): Enablement Alignment with Toronto Hydro's IT Standards User Experience Pillar: Maintenance Topic(s): Vendor Support Cyber Security Risks IT Reliability Control of Product Feature	• User accounts should be authenticated using Toronto Hydro's corporate active directory • User authorizations should be implemented using role-based user groups stored in active directory • User authorizations, existing roles and profiles from SAP ERP need to be migrated to S4 HANA • The system must handle single sign on with the applicable Toronto Hydro standard technology • The at rest data in the databases must be encrypted • Data in the lower environments must be scrambled or masked • The system must adhere to the standards for internal access, external supplier access, security technology, application security, network security and vulnerability management