D1 Asset Management Process Overview

Section D of the Distribution System Plan ("DSP") details Toronto Hydro's asset management process, which is the systematic approach the utility uses to:

- Collect, organize, and assess information on its physical assets and current and future operating conditions;
- Assess the utility's business priorities and customer focused goals and objectives in relation to its assets; and
- Plan, prioritize, and optimize expenditures on system-related modifications, renewal, operations, and maintenance, and on general plant facilities, systems and apparatus.

Toronto Hydro's primary asset management process is its Asset Management System, which addresses all distribution system assets and is referenced throughout the DSP as the "AM System", "AMS" or "AM Process". The utility's processes for non-system (i.e. general plant) assets are generally aligned with the AMS, relying on many of the same principles, inputs, and evaluative frameworks. However, as there are subtle but relevant differences between the distribution system and general plant processes, Toronto Hydro has included separate, supplemental sections dedicated to the particulars of the asset management processes for general plant assets. Overall, Toronto Hydro has the following major asset management areas:

1) Asset Management System ("AMS") for distribution assets;
2) Information and Operational Technology ("IT/OT") Asset Management; and
3) Facilities Asset Management.

The processes and details for each of these asset management areas are provided in the following sections:

- **Section D1** provides an overview of the asset management strategy and planning process for distribution assets, including the translation of corporate and stakeholder requirements into asset management objectives for the distribution system as well as for the AM system. This section also describes the asset management strategy, including continuous improvement initiatives that have been completed or commenced, with an emphasis on initiatives in the period since the OEB's December 19, 2019 decision on Toronto Hydro's 2020-2024 Custom IR application.

- **Section D2** describes the current state of the distribution system based on asset demographics, system configurations and various observable features of Toronto Hydro's distribution service area, including expectations for the continuing evolution of these features over the forecast period and beyond.
- **Section D3** describes Toronto Hydro's asset lifecycle optimization practices that aim to balance asset cost, risk and performance.
- **Section D4** describes the changing energy landscape, how Toronto Hydro developed its *Future Energy Scenarios*, and how that work has shaped its 2025-2029 load, generation, and Non-wires Solutions related capital investment.
- **Section D5** describes Toronto Hydro's Grid Modernization Roadmap that aims to adapt the distribution system and operations to the evolving needs of the energy landscape.
- **Section D6** describes the asset management approach for facilities assets.
- **Section D7** describes Toronto Hydro's plan to achieve Net Zero for direct greenhouse gas emissions from its operations by 2040.
- **Section D8** describes the asset management approach for IT/OT assets.

In addition to the major areas listed above, the utility also utilizes a robust approach to the management of its fleet assets, described within the Fleet and Equipment capital program in Section E8.3 of this DSP.

The various asset management processes provide the architecture for long-term, short-term, and maintenance planning functions. Toronto Hydro applied these processes in developing the 2025-2029 Capital Expenditure Plan, described in Section E of the DSP, and the system maintenance plans, described in Exhibit 4, Tab 2, Schedules 1-5.

Toronto Hydro's Commitment to Achieving ISO 55001 Certification

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

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

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

D1.1 Asset Management Objectives and Outcomes

Toronto Hydro's asset management objectives are to a large extent driven by relevant legislative and regulatory obligations and guidance such as the OEB's Distribution System Code ("DSC") and the *Electricity Act, 1998*, including:

- Following good utility practices for system planning to ensure reliability and quality of electricity service on both a short-term and long-term basis;[1]
- "[Ensuring] the adequacy, safety, sustainability and reliability of electricity supply in Ontario through responsible planning and management of electricity resources, supply and demand";[2] and

[1] Ontario Energy Board, Distribution System Code, Section 4.4.1
[2] Electricity Act, 1998, Section 1.

- "[Protecting] the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service".[3]

Additionally, Toronto Hydro aligns its AMS with other applicable legislative and regulatory requirements and principles, including the *Ontario Energy Board Act*, *1998*,[4] Toronto Hydro's Distribution Licence, the Standard Supply Service Code[5], and relevant City of Toronto by-laws.

Beyond its mandated service and compliance obligations, the broader objective of Toronto Hydro's AMS is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders. This requires continuously balancing near-term customer preferences with the need to ensure predictable performance and costs over the long-term for both current and future customers.

Toronto Hydro's AM strategy is in line with corporate strategy and stakeholder needs and preferences. AM objectives are set in order to achieve the AM strategy. Toronto Hydro has aligned its AMS with the utility's strategy for the regulated business, as described in Exhibits 1B, Tab 1 and Exhibit 2B Section E2 of the DSP.

Toronto Hydro's corporate strategy and associated business planning processes, including the AMS, are guided by a set of principles that align with the utility's five corporate pillars. As represented in Figure 1 below, the utility maintains a constant focus on these five pillars – Customer, Environment, Operations, People, and Financial – in a balanced way that promotes customer value and a sustainable business. These principles are an essential element in the determination and prioritization of outcomes.

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[3] Ibid.

[4] SO 1998, Ch 15, Sched. B

[5] Ontario Energy Board, Standard Supply Service Code (SSSC), "online", https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/standard-supply-service-code-sssc#:~:text=Sets%20out%20the%20rules%20that,connected%20to%20their%20distribution%20system.

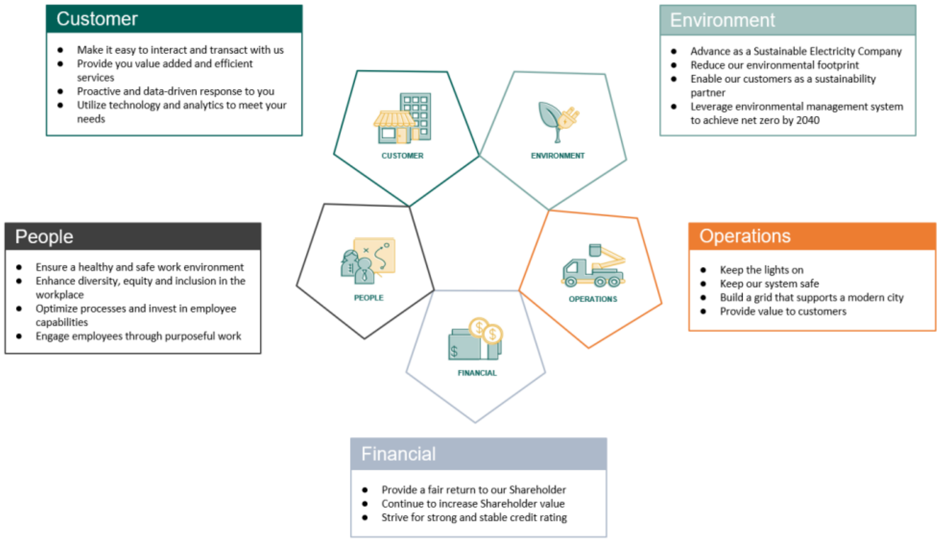


Figure 1: Toronto Hydro's Corporate Pillars

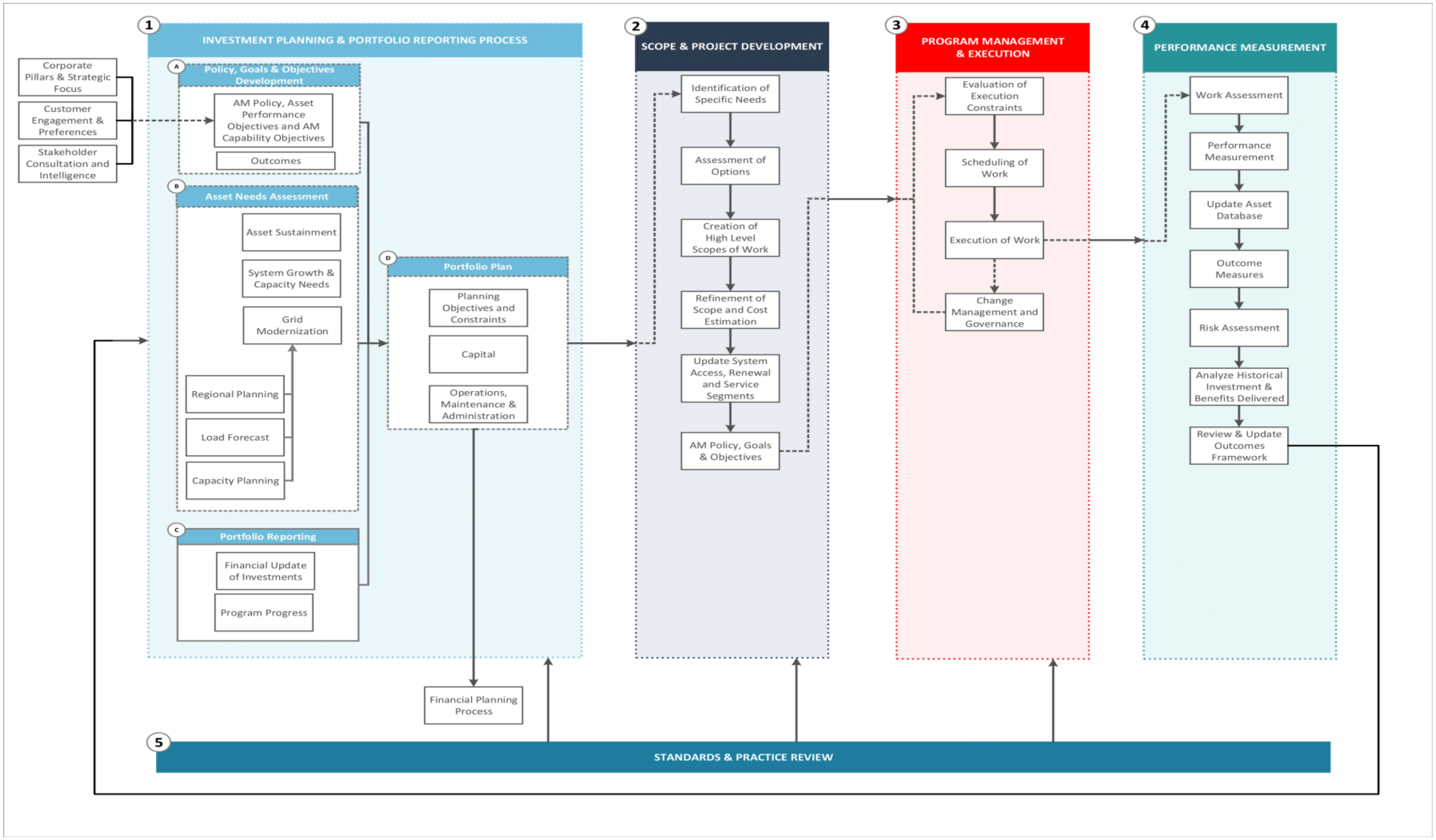
D1.2 Asset Management Process Overview

This section outlines the major elements of the AMS for distribution system assets, their inter-relationships, and the key inputs and outputs between each element.

The corporate direction outlined in the previous section determines the overall direction for decision-making throughout the AMS. At the same time, the information and performance results generated by the AMS inform the continuous refinement of corporate objectives, in balance with other considerations such as asset needs based on the current and future state of the system, customer engagement and benchmarking results.

Figure 2, below, illustrates the major planning and execution process elements of AMS, consisting of five main components:

- Investment Planning and Portfolio Reporting ("IPPR") Process;
- Scope and Project Development;
- Program Management and Execution;
- Performance Measurement; and
- Standards and Practice Review.



1 **Figure 2: Asset Management Process Overview**

The following sections outline each main component of the AM Process.

D1.2.1 Investment Planning and Portfolio Reporting ("IPPR") Process

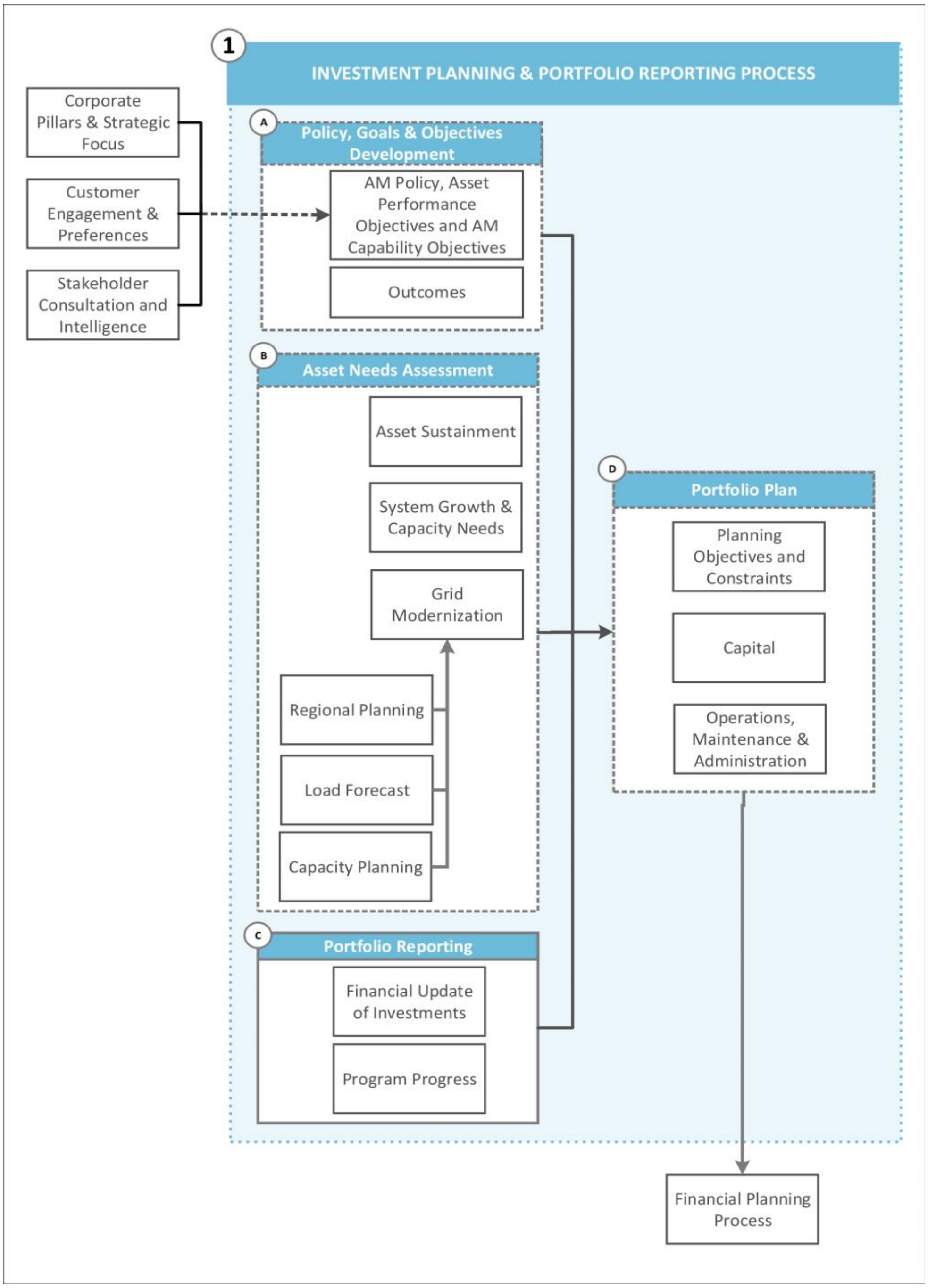


Figure 3: IPPR Process

The IPPR process is Toronto Hydro's system investment planning cycle, which includes both long-term and short-term planning horizons. The IPPR process aims to report on the current state of assets, forecast future states and associated risks, and assemble holistic investment plans. This integrated annual planning process involves:

- the analysis of current systematic needs and historic trends;
- the development of short-term and long-term plans – program forecasts, associated work volumes and performance objectives; and
- the optimization of different strategies by balancing financial constraints, risks, and outcomes.

It is composed of four sets of activities:

- **Policy, Goals and Objectives Development:** The IPPR process is guided by Toronto Hydro's asset management policy, goals and objectives. The utility periodically reviews and updates these elements to ensure continuous alignment of asset management decision-making with corporate strategy and customer and stakeholder needs and preferences. These activities are discussed in detail in section D1.2.1.1 below.
- **Asset Needs Assessment:** To determine the types and level of asset investment needed, Toronto Hydro tracks and analyzes the current state of its assets, their performance relative to a wide variety of risk indicators (e.g. environmental, reliability, and safety indicators), their ability to serve evolving demands from customers and external parties (e.g. bus-level load forecasts and evolving power quality needs), and grid enhancement and modernization roadmap. These activities are discussed in detail in section D1.2.1.2 below.
- **Portfolio Reporting:** Toronto Hydro monitors and assesses the progress of its system capital and maintenance programs against annual and longer-term budget, execution, and performance objectives. This helps ensure the utility is cost-effectively executing the DSP while making prudent adjustments in light of new information. These activities are discussed further in section D1.2.1.3 below.
- **Portfolio Planning**: Toronto Hydro uses the outputs of the above three activities to develop capital and maintenance investment plans for its portfolio of programs. These plans are the result of the utility's asset management goals and outcomes as applied to a combination of the current needs of the system and the current status of ongoing investment activities and accomplishments. Key aspects of the portfolio planning activity include the consideration of alternative investment strategies and the development of both short- and longer-term

expenditure plans for each capital program. These activities are described in detail in section D1.2.1.4 below.

Toronto Hydro executes all of the above activities annually, which ensures alignment between (i) the projects selected for execution within an annual capital plan and (ii) the utility's overall five-year expenditure plan and outcome objectives. The four major activities of the IPPR process are explained in further detail in the following sections.

D1.2.1.1 AM Policy, Asset Performance Objectives and AM Capability Objectives

Senior management direction for the AMS is provided through the Asset Management Policy and a set of strategic Asset Performance Objectives and AM Capability Objectives. The utility periodically reviews and, if necessary, adjusts these components of the AMS to ensure alignment with corporate strategy and evolving customer and stakeholder needs.

In 2022, as part of the utility's ongoing effort to align with the ISO 55001 standard for asset management, Toronto Hydro issued an updated corporate Asset Management Policy applicable to its distribution assets. This policy was developed in accordance with industry best practices and reflects Toronto Hydro's corporate strategy and organizational intent for managing its assets.

The substantive component of the Asset Management Policy is the following policy statement:

> *"Toronto Hydro's asset management policy is to ensure that it effectively manages its electricity distribution assets, across the complete asset lifecycle, in a safe, cost-effective, and sustainable manner, and that the management of those assets meets the needs of its customers and stakeholders, and provides a fair return to its shareholder. Toronto Hydro shall comply with all legal, regulatory and environmental requirements placed upon the organization and will prioritize the safety of its employees and the public.*
>
> *This Asset Management Policy shall be achieved through the management and continuous improvement of an efficient, coordinated, systematic, and embedded Asset Management System that:*
>
> - *develops and implements a Strategic Asset Management Plan;*
> - *balances costs, risks, opportunities and performance by applying a holistic approach to decision-making while:*

> - *optimizing the distribution system's reliability performance in accordance with customer needs and preferences;*
> - *enabling growth, fostering electrification, and accommodating evolving consumer and stakeholder needs; and striving for zero public and employee safety incidents.*
>
> - *aligns with Toronto Hydro's corporate strategy as well as its safety and environmental management systems;*
> - *collects and analyzes asset information to enable informed and holistic decision-making; and*
> - *ensures the availability of the required resources to develop and implement Asset Management strategies and plans.*
>
> *All employees and contractors shall comply with this policy and contribute towards the continuous improvement of the Asset Management System."*

Following the issuance of this policy in 2022, Toronto Hydro introduced a training module to foster company-wide awareness of the Asset Management Policy, the Asset Management System, and the benefits of continuous improvement in Asset Management. The utility also introduced formal Asset Management training programs to accelerate the onboarding and development of new employees, as well as a more intensive certification program for employees in key roles, to augment their understanding of the AMS, enable them to be stewards of the system, and foster a culture of continuous improvement.

As noted in the policy statement, the development of a Strategic Asset Management Plan ("SAMP") is an essential component of the AMS. Currently, the 2025-2029 Distribution System Plan (Exhibit 2B) serves as the utility's SAMP document. As Toronto Hydro continues its journey toward ISO 55001 certification, the intention is to develop a stand-alone SAMP document which will be updated more frequently and will form the basis for future DSPs.

Toronto Hydro's asset management strategy is encapsulated by two complimentary sets of objectives:

i. **Asset Performance Objectives**, which articulate Toronto Hydro's major customer- and stakeholder-focused performance objectives for its assets, i.e. "what" needs to be achieved with the assets; and

ii. **AM Capability Objectives**, which focus on the organization's capability to manage its assets, i.e. "how" the organization can manage its assets to achieve the performance objectives.

Toronto Hydro's Asset Performance Objectives for 2025-2029 are summarized in Tables 1 to 3 below. These objectives are aligned with the overall investment plan objectives and the utility's performance incentive framework and are a result of the detailed, iterative, and customer engagement-driven planning process summarized in Section E2 of the DSP.

Table 1: Asset Performance Objectives and Key Measures for Growth & City Electrification

OEB Performance Outcomes	Asset Performance Objectives (2025-2029)	Key Performance Measures
Customer Focus	• Connect customers efficiently and with consideration for an increase in connections volumes due to electrification • Accommodate relocations for committed third-party developments, including priority transit projects	1. New Services Connected on Time 2. Customer Satisfaction
Operational Effectiveness - Reliability	• Expand stations capacity to alleviate future load constraints, with consideration for increased electric vehicle uptake, decarbonization drivers, and other growth factors (digitalization and redevelopment) • Install control and monitoring capabilities for all generators > 50kW	1. System Capacity[6]
Public Policy Responsiveness	• 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 (i.e. flexibility services) • Alleviate constraints on restricted feeders to accommodate the proliferation of DER connections, including by supporting customers and third-parties to more easily identify optimal locations for DER projects	1. System Capacity 2. Restricted Feeders (DERs) 3. Distributed Generation Facilities Connected on Time

[6] System Capacity includes bus loading, heat restricted feeders, feeder position availability, etc.

1 **Table 2: Asset Performance Objectives and Key Measures for Sustainment & Stewardship**

OEB Performance Outcomes	Asset Performance Objectives (2025-2029)	Key Performance Measures
Operational Effectiveness - Safety	• Adhere to previous commitments for safety compliance activities (e.g. complete Box Conversion by 2026)	1. Total Recordable Injury Frequency 2. Serious Electrical Incident Index 3. Box Framed Poles Remaining on the System 4. Non-Energy Mitigating Cable Chamber Lids in High Risk Locations
Operational Effectiveness - Reliability	• Maintain recent historical system reliability, which includes: ○ leveraging risk-based decision-making to ensure System Renewal investments are sufficient to maintain recent historical reliability for outages caused by Defective Equipment; and ○ leveraging the Worst Performing Feeder program and other intervention tactics to improve reliability for customers experiencing service that is much worse than average • Manage asset risk by maintaining overall health demographics of the asset population in 2025-2029 • Optimize the pace of renewal investment from year-to-year using risk-based decision-making tools	1. Defective Equipment Outages (SAIDI, SAIFI) 2. Worst Performing Feeders (e.g. FESI) 3. Asset Health 4. % Assets Past Useful Life 5. Rear Lot Customers on System 6. Direct-buried Cable on System (km) 7. Network Modernization (% of submersible units)
Public Policy Responsiveness	• Adhere to previous commitments for environmental compliance activities (e.g. removal of at-risk PCBs by 2025)	1. PCB-contaminated Oil Spills 2. Lead Cable Remaining on System (km)
Financial Performance	• Ensure investment pacing contributes to stable long-term investment profiles for all assets (2030+)	1. Asset Health 2. % Assets Past Useful Life 3. Network Modernization (% of submersible units)

1 **Table 3: Asset Performance Objectives and Key Measures for Modernization**

OEB Performance Outcomes	Asset Performance Objectives (2025-2029)	Key Performance Measures
Customer Focus	• Prioritize technology investments that will deliver demonstrable benefits to customers, especially enhancements that will enhance value-for-money in the long-term (i.e. efficiency) • Leverage technology to improve customer experience (e.g. customer tools)	1. Customer Satisfaction 2. Bill Accuracy 3. Estimated Time of Restoration (ETOR) 4. Customer Escalations Resolution
Operational Effectiveness - Reliability	• Improve system reliability through greater system controllability (e.g. SCADA-enabled sectionalizing points) and enhanced fault management technologies, including advanced metering infrastructure (AMI 2.0) • 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 • Leverage technology to improve customer experience (e.g. reliability, power quality) • Enhance system observability, enabling better asset management and operational decision making and expanding the foundation for advanced distribution automation	1. Grid Automation Readiness 2. System Reliability (e.g. SAIFI, SAIDI) 3. Load Secured During Contingency Event (e.g. Loss of Supply)
Public Policy Responsiveness	• Leverage technology to improve customer experience (e.g. DER integration)	1. Restricted Feeders (DERs) 2. Distributed Generation Facilities Connected on Time
Financial Performance	• Prioritize technology investments that will deliver demonstrable benefits to customers, especially enhancements that will enhance value-for-money in the long-term (i.e. efficiency)	1. Grid Automation Readiness 2. System Capacity (Non-Wires) 3. Efficiency Achievements

As part of its effort to achieve ISO 55001 certification, Toronto Hydro is developing a detailed asset management roadmap which will lay out a series of longer-term AM Capability Objectives that the utility intends to pursue in the years ahead. Many of these capability building efforts fall into one of three strategic categories, which align with the utility's overall modernization and performance strategy for 2025-2029 and beyond:

1. **Enhancements to Risk-based Asset Management and Investment Portfolio Optimization Tools:** Toronto Hydro is currently executing a multi-year project to implement an industry-leading value framework within its new Engineering Asset Investment Planning ("EAIP") platform, Copperleaf C55. The EAIP platform is a powerful decision-support tool that facilitates consistent and objective value-based optimizations of the utility's substantial portfolio of capital projects.

   At the heart of this tool is a custom value framework that Toronto Hydro is currently developing which assigns relative value to investments based on their likely contribution to Toronto Hydro's key performance outcomes. For many of these investments, including a majority of the System Renewal programs, this value framework is built directly upon the utility's Condition Based Risk Management ("CBRM") framework, ensuring that projects will be consistently prioritized on the basis of their verifiable contributions to mitigating quantifiable condition-based asset risk. As discussed in D1.3.2.1 and in Section D3, Toronto Hydro is committed to continuously reviewing and enhancing its CBRM to ensure alignment with the observed reality of its assets in the field. The utility is also committed to researching and developing more sophisticated risk-based decision frameworks for assets that do not currently have condition-based models, including underground cable systems, in the 2025-2029 period.

   As for its EAIP tool, Toronto Hydro is currently on track to begin leveraging its optimization capabilities for the majority of its investment program by the beginning of the 2025-2029 period. Following EAIP implementation, Toronto Hydro plans to extend the use of its value framework upstream of the EAIP tool as part of a predictive/prescriptive analytics solution which will assist investment planners in identifying project candidates with the greatest potential value to customers.

2. **Asset Information Strategy and Governance:** As part of its journey toward ISO 55001 certification, the utility is in the process of developing an Asset Information Strategy that

outlines current and future asset information needs. This will be accompanied by a system agnostic Asset Information Standard document, which will help improve consistency in how mission-critical asset and customer information is classified, stored, and assessed for quality. Toronto Hydro also intends to develop a more comprehensive and rigorous data and analytics governance framework to support the development and adoption of decision-making tools and insights that can drive greater efficiency and performance. Toronto Hydro believes that greater use of data and analytics will be a significant driver of value in the 2025-2029 period and beyond. Furthermore, highly accurate and accessible asset and system data will be essential to the successful implementation of next-generation operational forecasting and automation tools such as the Advanced Distribution Management System and Distributed Energy Resource Management System. As part of the Grid Modernization Roadmap, the Asset Analytics & Decision-making portfolio covers Toronto Hydro's plans to fully and sustainably leverage the value of existing and new forms of distribution system data and intelligence. One of the domains of this portfolio involves integration of relevant enterprise systems into a fully harmonized asset data registry for asset planning. Some of the relevant enterprise systems are: the utility's Geographical Information System ("GIS"), Enterprise Resource Planning ("ERP") system, and Customer Care & Billing ("CC&B") system. The Asset Analytics & Decision-making portfolio is further described in Exhibit 2B, Section D5.

3. **Developing Enhanced Asset Analytics:** Toronto Hydro is currently ramping up its efforts to develop a more robust asset data analytics function. This effort involves three major elements: (i) recruiting and developing engineers and analysts with progressive data analytics and coding skillsets, (ii) researching, evaluating, and procuring advanced analytics solutions to meet specific asset management and operational needs and (iii) investing in the information technologies necessary to support efficient and effective use of data for analytics and machine learning applications. The utility has a rich trove of data which can be leveraged to create new insights to support better decision-making, and observability enhancing technologies such as AMI 2.0 promise to provide a step increase in the amount of data available to planners and system operators in the years to come. In the last several years, Toronto Hydro has made headway with respect to building out its analytics applications, for example by investing in the province's first long-term, distribution-level scenarios model for the energy transition, and developing

several pilot applications (not yet in production), including a homegrown electric vehicle detection model prototype, and a machine learning concept for predicting the cause of "Unknown" outages. Toronto Hydro plans to make accelerated investments in its asset analytics and machine learning capabilities over the next six years, including enhancing its use of simulation platforms to develop more robust insights into emerging challenges such as the capacity to host DERs on its system. As part of the development and evolution of Toronto Hydro's Asset Analytics & Decision-Making modernization strategy, the utility plans to enable predictive and prescriptive analytics in the utility's business processes through the use of advanced tools, such as artificial intelligence and machine learning (further described in Exhibit 2B, Section D5).

In addition to these three major categories of AM Capability Objectives, Toronto Hydro plans to pursue a variety of other enhancements to its AMS and AM capabilities, including planning process improvements, enhanced forecasting tools to support continuous improvement in areas such as supply chain management and construction labour balancing, and digital process automation to improve the efficiency and consistency of many elements of the AMS.

D1.2.1.2 Asset Needs Assessment

Toronto Hydro completes a needs assessment of its distribution system to determine the type of investments required. This includes determining the current state of assets, identifying system needs and challenges, and incorporating load forecasts and regional planning results. Further details on these focus areas and how they are used in developing the investment plans can be found in Section D3.2.

Toronto Hydro regularly performs a foundational analysis to understand the current state of the distribution system in terms of asset properties and quantities, asset performance risk (e.g. age, condition, and obsolescence), historical reliability, and asset utilization (e.g. capacity to connect customers and serve peak load). There are three areas Toronto Hydro focusses on to determine current and future asset needs: Asset Sustainment, System Growth and Capacity Needs, and Grid Modernization.

1. ***Asset Sustainment***

Toronto Hydro aims to ensure stable long-term performance of its assets, maintain system reliability, and minimize asset failure risk. When an asset is assessed to be in poor condition, it is considered for repair, upgrade or replacement under current standards (including regulatory and Toronto Hydro standards).

The typical planning process includes a review of:

- Condition Based Risk Framework;
- Assets Past Useful Life; and
- Potential Consequences of Failure.

Toronto Hydro's Asset Condition Assessment ("ACA") is the utility's Condition Based Risk Management ("CBRM") Framework. The ACA methodology assigns health index scores to assets based on an observable condition variable. These scores are categorized within five health index bands ("HI1" to "HI5") to support project planning. Asset condition demographics are a strong indicator of future asset performance and reliability. Toronto Hydro aims to keep assets within the HI3 ("moderate deterioration") to HI5 ("end of serviceable life") bands stable, with a particular emphasis on managing the shorter-term risks associated with HI4 and HI5 assets. The ACA allows Toronto Hydro to use data collected through inspections to establish a numerical representation of the condition of an asset by considering factors such as operation, degradation and lifecycle. The health score of an asset helps Toronto Hydro optimize asset replacement plans by indicating whether an asset has a higher or lower probability of failure than age alone would indicate. The ACA model also allows the utility to project future asset condition at an aggregate population level, which supports effective investment program pacing during the planning process.

Toronto Hydro is implementing probability of failure curves to derive a stronger and more objective relationship between condition and functional failures. Toronto Hydro's Probability of Failure methodology uses historical failure data in conjunction with the generated health scores from ACA.

In addition to ACA data and the development of probability of failure curves, asset age has a strong correlation with the likelihood of asset failure. Its simplicity and availability make it an informative source of data for system-wide analysis (e.g. reliability forecasting), particularly for longer time horizons. Toronto Hydro considers age by leveraging its Assets Past Useful Life ("APUL") analysis, which determines the proportion of assets currently past their useful life and expected to be without investment in the next five years. This analysis is done at the system level and for individual asset classes and is used to inform the pacing of renewal programs to ensure long-term stability/sustainability in combination with asset condition where available.

ACA, probability of failure and age are leading indicators of failure, and, by extension, the future reliability, safety, and environmental performance of Toronto Hydro's system. As noted above, Toronto Hydro also considers historical reliability – a lagging indicator of performance – in its asset needs assessment. Actual reliability helps to identify areas of poor or worsening performance and is a useful input in project prioritization. Historical reliability can also be a leading indicator of asset failure in specific circumstances.

Toronto Hydro also considers the potential consequences of failure when assessing asset needs. For example, an air-insulated pad-mount switch that is known to carry a higher risk of flashover compared to other pad-mount switches, posing employee and public safety risks, has a heightened consequence of failure and is therefore a higher priority for replacement.

2. System Growth & Capacity Needs

Toronto Hydro determines capacity and connection needs through the System Peak Demand Forecast, load connections forecasting, generation connections forecasting, and the Regional Planning process.

The 10-year weather-adjusted peak demand forecast ("System Peak Demand Forecast") is developed using a driver based, top-down forecasting methodology and is fundamental to the capacity planning process, including the stations capacity planning process which enables Toronto Hydro to identify capacity availability and anticipated constraints at substations in relation to future load growth. It forecasts the peak demand at all transformer station buses that supply Toronto Hydro's distribution grid. The System Peak Demand Forecast considers new load connections, increased distributed energy resources ("DERs"), electrification of transportation and fuel switching. Further information on the System Peak Demand Forecast can be found in Section D4.

To prepare for growth and electrification in the City of Toronto, Toronto Hydro has adopted additional growth and electrification drivers into its System Peak Demand Forecast. The inputs include (i) hyperscale data centers, (ii) electrification of transportation and (iii) Municipal Energy Plans which include large anticipated connections in different areas of the city.

Furthermore, in preparation for the 2025-2029 investment planning cycle and as a way of complementing and further contextualizing the capacity planning process, Toronto Hydro introduced the Future Energy Scenarios ("FES") model. FES is a bottom-up, consumer choice model that produced projections for peak load (kW), generation (kW), and energy consumption (kWh) under a variety of potential energy system transformation scenarios. Toronto Hydro's goal for the FES project was to enrich its long-term strategic planning capabilities and provide its stakeholders with an understanding of the way in which electricity demand, consumption and generation may change in the future and the range of uncertainty involved. Further information on FES can be found in Section D4, including a detailed discussion in the associated Appendix A.

In addition to the System Peak Demand Forecast, there are load and generation connections forecasting processes, which result in forecasts of the amounts of expenditures required to accommodate anticipated load and generation customers.

The Customer Connections program captures system investments that Toronto Hydro is required to make to provide customers with access to its distribution system. This includes enabling new or modified load and distributed energy resources ("DER") connections to the distribution system following legal and regulatory obligations under various statutes and codes. The work also includes any expansion work necessary to address capacity constraints for the purpose of connecting customers. 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. See Exhibit 2B, Section D2 for more details.

Toronto Hydro supports connecting DERs to the distribution system in alignment with the Distribution System Code, and in coordination with Hydro One Networks and the IESO. Toronto Hydro continues to see interest in solar generation, as customers seek to reduce bills (through the Net Metering program) and achieve ESG objectives.

Finally, the Regional Planning Process is a key element of distribution system planning and stations-level planning in particular. Toronto Hydro participates in infrastructure planning on a regional basis to ensure regional issues and requirements are effectively integrated into the utility's planning processes. Toronto Hydro participates in the Central Toronto Integrated Regional Resource Plan, led by the Independent Electricity System Operator, and in the Regional Infrastructure Plan for Metro Toronto Region and GTA North Region, led by Hydro One Networks Inc. Additional details on the Regional Planning process are discussed in Section B2.

3. *Grid Modernization*

Toronto Hydro is at an important turning point in its modernization journey. 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. DERs) – threatens to overwhelm grid capacities and capabilities in the long-term if not proactively addressed. To avoid both (i) long-term decline in system performance and (ii) becoming a barrier to the energy transition (in terms of both long-term costs to ratepayers and the grid's ability to serve and integrate customer loads and resources), Toronto Hydro has determined that it is necessary to accelerate strategic investment in specific field and information technologies that will deliver near-term benefits to customers while setting the utility on a path toward sustainable performance and improved efficiency as the pressures of climate change and the energy transition mount.

Toronto Hydro's overarching grid modernization plan is detailed in the Grid Modernization Strategy section found in Section D5. This strategy is the result of a cross-functional strategic planning effort undertaken in parallel with the typical business planning process over the course of 2021 and 2022. The focus and pacing of the investments featured in the Grid Modernization Strategy were informed by various strategic inputs, including customer and stakeholder engagement, government and regulatory policy, energy transition outlooks (including Toronto Hydro's own Future Energy Scenarios), engagement with industry groups and experts, publicly available literature regarding modernization efforts in leading jurisdictions (including examples of utilities and jurisdictions actively pursuing Distribution System Operator, or "DSO", capabilities), and an assessment of Toronto Hydro's existing grid modernization maturity versus the desired future state in 2030 and 2035. As detailed in the Grid Modernization Roadmap, Toronto Hydro has categorized these capability-building investments into three broad categories:

- **Intelligent Grid:** updating the existing distribution grid and introducing automation to deliver reliability and resiliency improvements, enhance system observability, and enable enhanced real-time decision-making;
- **Grid Readiness:** preparing the distribution system and operations to integrate DERs and leverage Non-Wires Solutions; and
- **Asset Analytics & Decision-making**: building on existing and future data sources and telemetry (sensors) to create value-added analytics and tools for enhanced planning, decision-making, and customer and stakeholder engagement

The Grid Modernization expenditure plans for 2025-2029 are integrated throughout Toronto Hydro's investments programs in Sections E5-E8. For a comprehensive guide to where specific modernization expenditures are found, please refer to Exhibit 2B, Section D5 and Section E2.

D1.2.1.3 Portfolio Reporting

As part of the IPPR process, Toronto Hydro monitors and reports on the progress of capital programs, which includes program level expenditures, project-specific execution status and project expenditures. The utility monitors changes in system-level outcomes (e.g. average reliability) and the effects of specific programs on specific outcomes (e.g. the reduction in the number of poles in end of serviceable life condition) during the Performance Measurement stage of the AM Process. This performance information is available to Toronto Hydro's planners to assess the benefits of the program to-date and identify necessary pacing and prioritization adjustments to meet objectives or emerging needs in future years.

D1.2.1.4 Portfolio Planning

The final piece of the annual IPPR Process is the development of the plan itself. Toronto Hydro planners use information from the Asset Needs Assessment and the Portfolio Reporting Process to develop capital investment and maintenance plans that support the achievement of the utility's asset management strategies and outcomes in alignment with customer needs and preferences.

1. *Capital Programs*

Toronto Hydro develops capital programs that address the needs and challenges of the system in alignment with strategic focus areas and customer preferences. The utility develops the programs to maintain and improve reliability and safety, meet service and compliance obligations, address load capacity and growth needs, tackle resiliency and business continuity risks, improve contingency constraints, and make necessary day-to-day operational investments. For the purpose of structuring the 2025-2029 business planning approach, these programs are categorized into the following four focus areas:

- Growth and City Electrification;
- Sustainment and Stewardship;
- Modernization; and
- General Plant.

On overview of these capital programs is provided in Section E2. A summary of how these programs map to the OEB's investment categories of System Access, System Renewal, System Service and General Plant can be found in Section E4 of the DSP.

2. Maintenance Programs

Toronto Hydro's maintenance planning process is designed to assess the condition, extend the life, and maintain the reliability of distribution assets. The utility designs its maintenance programs to extract the maximum value from existing assets. Maintenance typically occurs on set frequencies derived from Reliability Centered Maintenance ("RCM") standards and the OEB's minimum inspection requirements in Appendix B of the Distribution System Code ("DSC").

Toronto Hydro has four major categories of maintenance:

- **Preventative Maintenance:** Typically involves cyclical inspection and maintenance tasks, which emphasize assessing asset condition and preserving asset performance over the expected life of the asset, and maintaining public and employee safety.
- **Predictive Maintenance:** Involves testing or auditing equipment for a predetermined condition (or conditions) to anticipate failures, then undertaking the maintenance tasks necessary to prevent those failures.
- **Corrective Maintenance:** Involves repairing or replacing equipment after a deficiency has been reported, such as actions taken after emergency response crews have restored power following an outage. Corrective Maintenance actions may also result from deficiencies discovered during the execution of Preventive or Predictive Maintenance tasks or other planned work.
- **Emergency Maintenance:** Involves the urgent repair or replacement of equipment when the equipment fails, often causing power disruptions to Toronto Hydro customers.

The details of the maintenance programs in these categories can be found in Exhibit 4, Tab 2, Schedules 1-5.

Toronto Hydro ensures that capital and maintenance programs are coordinated by planning and reporting on both activities within the IPPR process. Maintenance programs account for changes associated with capital investment programs, such as new asset classes being introduced or existing asset classes being eliminated. For example, Toronto Hydro completed its planned replacement of Automatic Transfer Switches and Reverse Power Breakers as of 2022. With the elimination of these asset classes, maintenance plans were modified accordingly.

3. *Pacing and Prioritization*

Toronto Hydro paces its expenditure plans to support the achievement of multi-year outcome objectives (e.g. maintain or improve reliability over a number of years). Pacing decisions are informed by various leading and lagging indicators of risk and performance (e.g. asset condition demographics, reliability projections, reliability results), and an assessment of various risk mitigation alternatives, as discussed in Section D3.2.

Program expenditures are reprioritized annually based on actual accomplishments and measured performance relative to the multi-year plan, as well as ongoing analysis of evolving system, customer, and stakeholder needs. Toronto Hydro prioritizes projects within and across programs in accordance with anticipated project benefits, estimated costs, and an assessment of execution capabilities and constraints. On this basis, the lowest priority projects are deferred to future years, and the projects that offer the greatest value-for-money relative to the utility's customer-focused objectives are scheduled for execution.

D1.2.2 Scope and Project Development

The scope and project development component of the AM Process involves the development of discrete projects within each investment program. This process involves four components: identification of specific needs, assessment of options, development of high-level project scopes of work ("scopes"), and refinement of scopes and cost estimates.

The investment proposals from IPPR identify and prioritize the assets or issues that require intervention within each capital program. As part of the early stages of scope development, Toronto Hydro identifies the assets and issues in discrete geographical locations through the use of decision support tools. The utility considers alternatives while developing a scope, which include various engineering options available to address an issue. The utility then evaluates the options with consideration for risks, required performance, customer preferences, effects on third parties, adjacent investments, reconfiguration opportunities, and the overall costs versus benefits. Finally, the utility selects the preferred option for the specific area or issue being addressed, and collects and summarizes asset information for replacement or refurbishment along with high-level specifications for new assets to be installed as part of a conceptual design. This constitutes the initial scope of work.

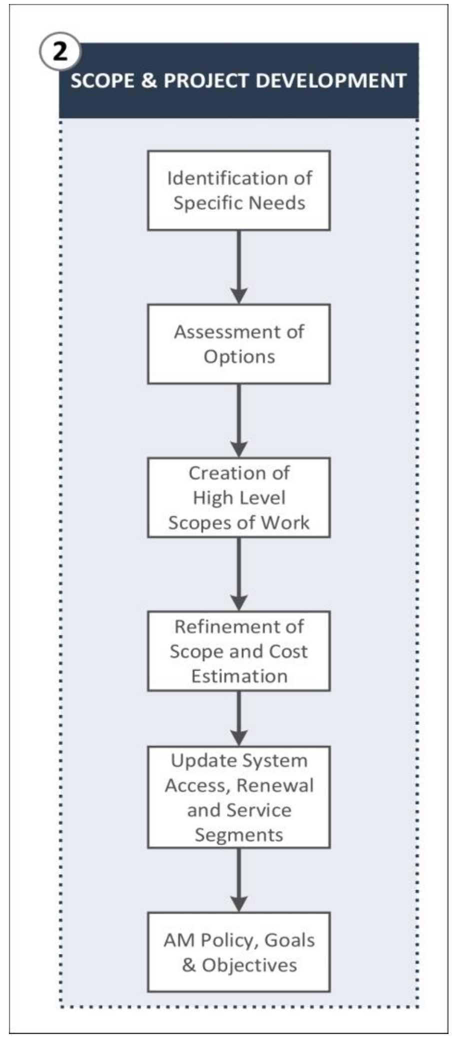


Figure 5: Scope and Development Stage

The next step is the project development stage, during which a cross-functional team of engineers, designers and field staff take the initial scope of work, assess feasibility and field conditions and execution risk. Project Development then produces refined scopes of work, preliminary designs and estimates, and aligns projects with execution work programs to allow for the most efficient use of resources. The project development team engages with internal and external stakeholders to ensure project timelines can be met, and to avoid conflicts and delays when a project is undergoing construction.

Where appropriate, the project development phase may break an original scope of work into smaller project phases for execution. This could be done for various reasons, including coordination with other work in the system, or to meet external constraints related to the location or the type of work. In the project development phase, the utility also undertakes initial project enabling tasks such as acquiring permits and coordinating with third parties prior to beginning final project design and construction. This helps to avoid design and scheduling uncertainty that can arise later in the process. As part of the project development process, Toronto Hydro also considers issues such as city road moratoriums, physical restrictions, or particular design related problems that may delay the project or require a redesign.

D1.2.3 Program Management and Execution

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

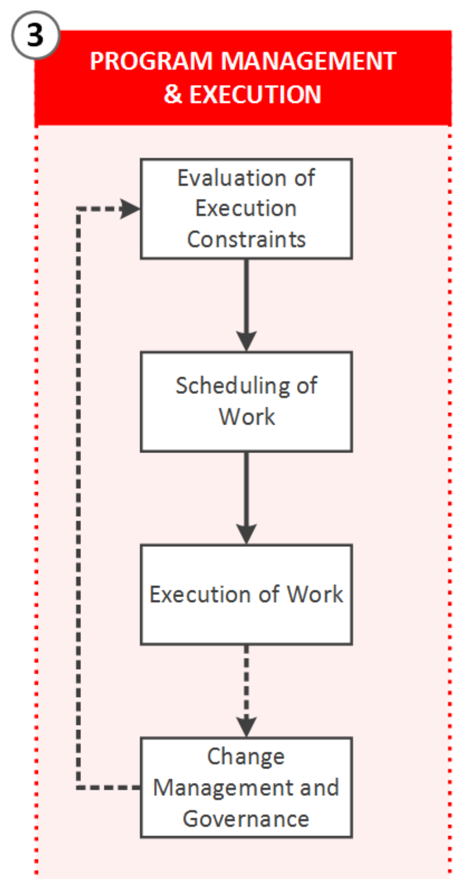


Figure 6: Program Management and Execution Stage

The "evaluation of execution constraints" stage considers multiple factors such as available resources, road moratoriums, switching restrictions, and coordination opportunities. Program managers, in coordination with system planners and in alignment with strategic objectives, select a prioritized mix of projects to be executed in a given year. Some of these projects involve assets to be replaced or issues to be resolved that are of the most urgent nature. Prioritization of work aims to balance renewal work with the emerging needs of the system. Toronto Hydro anticipates improvements in both the efficiency and effectiveness of this stage of the planning process as it continues to implement and integrate its new EAIP optimization tool.

Once Toronto Hydro develops an execution plan, the actual execution of work is monitored from the detailed design stage through the construction stage. Projects are closely tracked to proactively identify and manage risks that may impact the successful delivery of the planned work.

Toronto Hydro monitors changes to projects through a change management and governance process. This process includes monthly executive performance reporting, key program status reporting, change request process management, project variance analysis, and numerous metrics to drive process adherence and continuous improvement. Depending on the magnitude of a required change to a project's cost, schedule, or scope of work, the change may require a detailed assessment of alternatives and formal approval from senior management and the executive team before proceeding.

Exhibit 4, Tab 2, Schedule 10, Section 8 provides further details about the processes utilized in the Program Management and Execution stage of the AM Process.

D1.2.4 Performance Measurement

The final stage of the AM Process is to monitor the performance of the investment program, and to determine to what extent projects have contributed to expected outcomes. These results feed back into the annual IPPR process so that Toronto Hydro can modify programs and refine objectives as appropriate.

Some key examples of outcome measures that Toronto Hydro tracks in relation to the capital and maintenance expenditure plans include:

- Asset Health Index;
- Reliability (e.g. SAIDI and SAIFI);
- Program Accomplishments (e.g. box poles removed)

Further details on Toronto Hydro's performance measures for the 2025-2029 DSP are provided in Section D1.2.1.1 and Section E2.

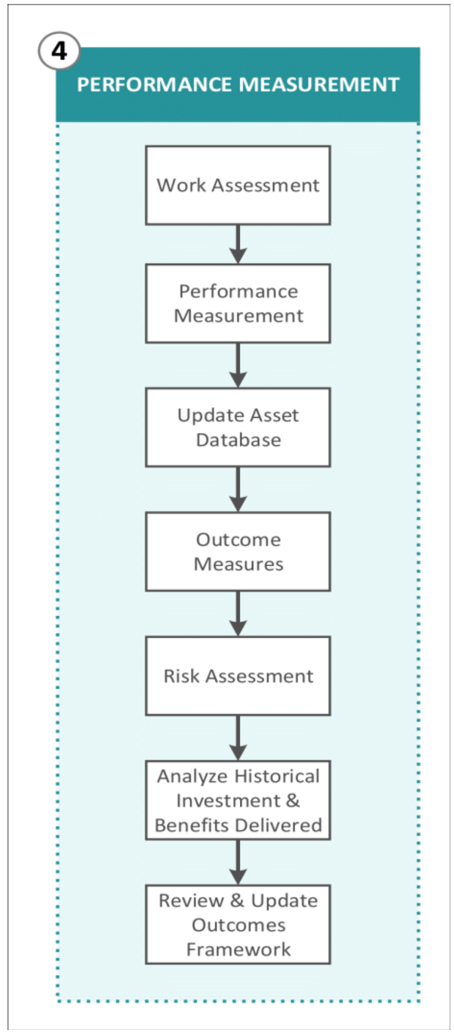


Figure 7: Performance Measurement Stage

D1.2.5 Standards and Practice Review

The Standards and Practice Review is driven by the need to evaluate particular standards and products to improve work execution and manage safety risks. This process influences three stages of the AM Process as planners, designers, and crews rely on this process to identify what equipment is available to them and its appropriate use. The review encompasses the necessary specifications and processes related to: (i) introducing standards and assets into the system; (ii) installation requirements; (iii) replacement considerations; (iv) identifying new assets to better meet system needs and customer preferences; (v) carrying out work in a consistent manner; and (vi) supporting improved safety.

1) **New and revised standards:** Toronto Hydro routinely introduces new standards and revises existing standards to ensure safe and effective work execution. New standards are created in response to a number of drivers, including but not limited to: (i) climate change risks; (ii) process or productivity improvements; (iii) equipment quality; and (iv) safety risks. When Toronto Hydro revises a standard, other documents, such as the Standard Design Practices followed by project designers, are updated to align with changes made.
2) **New products:** Introducing new products enables more efficient, safe, and reliable service to customers. Product requests are reviewed to ensure alignment with business needs, that the appropriate stakeholders are engaged, and that the product satisfies Electrical Safety Authority ("ESA") requirements for major and minor equipment approval. The need for a new product can be initiated for a number of reasons, including: (i) safety; (ii) productivity; and (iii) reliability. For example, Toronto Hydro plans to install reclosers on the trunk and laterals of feeders that will provide automated and remote controllability functions to address feeders experiencing numerous momentary and sustained interruptions, resulting in reduction in overall outage times and improvement in system resiliency.
3) **Refurbishment and replacement of equipment:** When major equipment, such as transformers, network protectors, and switches, is returned from the field, Toronto Hydro evaluates, inspects, and tests them to determine whether the asset can be reused (i.e. repaired or refurbished) or should be replaced (i.e. scrapped).
4) **Quality improvements:** When a product that is not near end-of-life is returned from the field because of failure, it is investigated to determine the root cause of the failure. Investigations are conducted in-house, by an expert third party, or by the original equipment manufacturer. If a manufacturing quality issue is discovered, the manufacturer is notified and requested to

make modifications to address the issue. If an installation quality issue is discovered, corrective and preventative actions include standards revisions, procedure changes, and additional training.

5) **Standard Design Practices:** The Standard Design Practices ("SDP") document provides guidance and instructions for the design of Toronto Hydro's distribution system. The SDP instills safety by design, enforces construction standards, and ensures alignment with business strategies and consistency between projects. The DSP set outs general guidelines with respect to technical matters, and refers to construction standards for specific details.

6) **Industry standards**: Toronto Hydro seeks to align with industry standards and best practices wherever possible. This avoids unnecessary custom-made products which can drive up costs and maintenance complexity. Toronto Hydro is part of an Inter-Utility Standards Forum ("IUSF"), through which utilities collaborate on solutions to common problems and develop common equipment specifications. Toronto Hydro is also a member of numerous standards committees of the Canadian Standards Association and the Institute of Electrical and Electronics Engineers.

D1.3 Asset Management Process Enhancements

Toronto Hydro's AM process continues to evolve. The utility is continuously enhancing its approach to asset management to ensure the process and strategies remain aligned with the needs of its customers and the distribution system.

The recent progression of Toronto Hydro's AM process is described in the following two sections:

- D1.3.1 – Enhancements during previous filing period (2015-2019); and
- D1.3.2 – Enhancements during the current filing period (2020-2024).

D1.3.1 Past Enhancements (2015-2019)

Improvements to Toronto Hydro's AM Process over the 2015-2019 period are highlighted in Figure 8 below. The following section provides additional details on key process improvements.

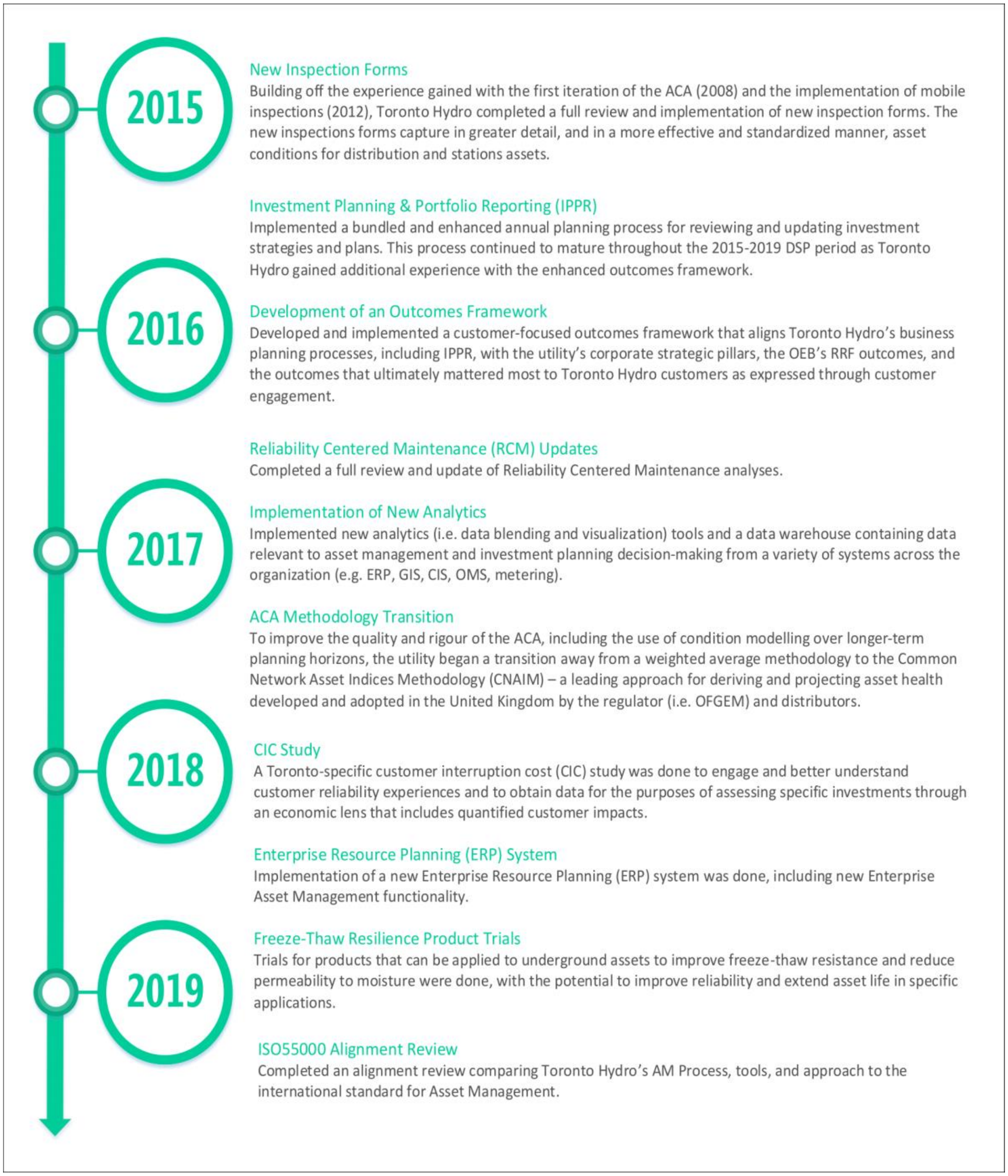


Figure 8: Past Enhancements of the AM Process (2015-2019)

D1.3.2 Recent Enhancements (2020-2024)

Figure 9 outlines improvements to Toronto Hydro's AM Process over the 2020-2024 period.

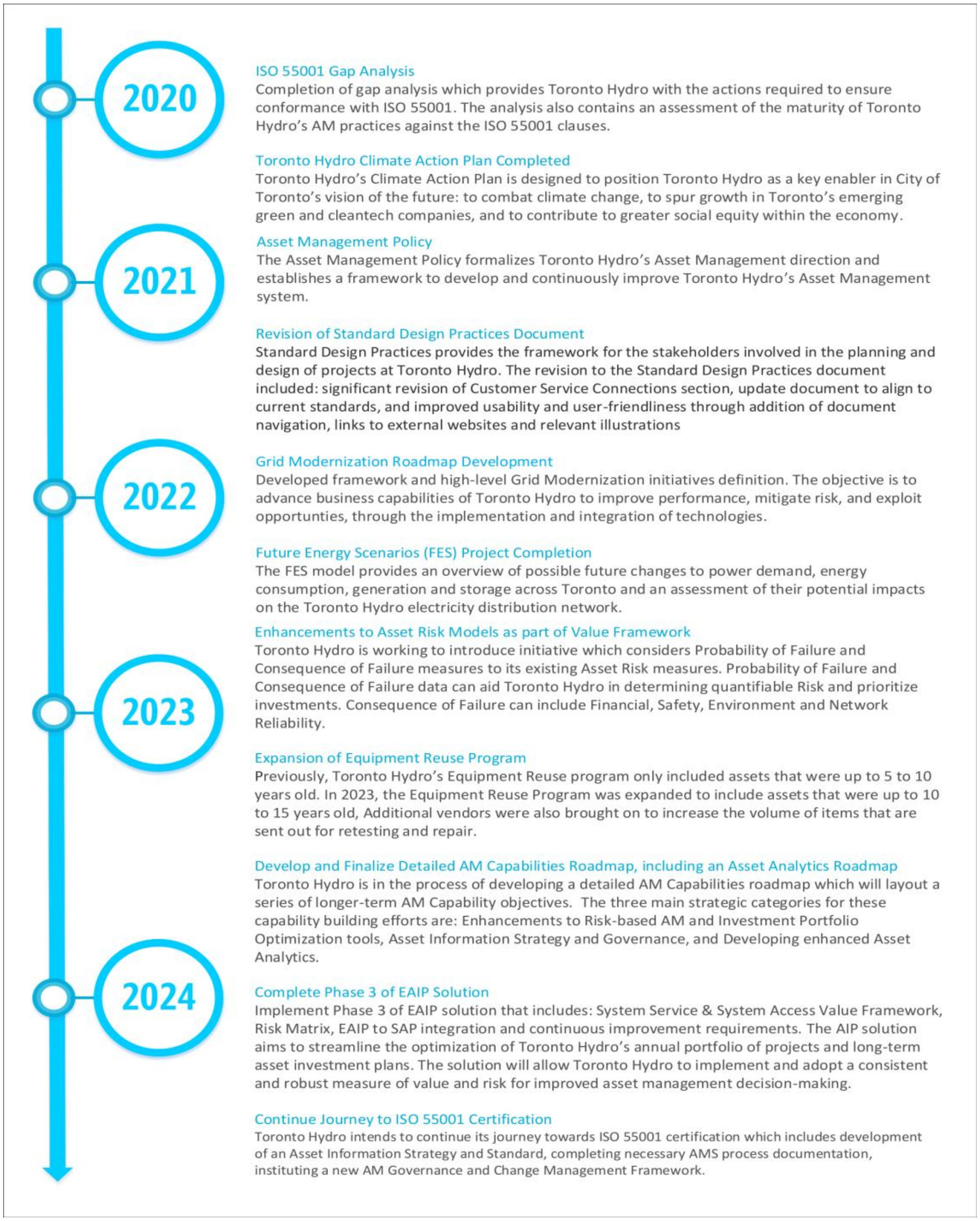


Figure 9: Recent Enhancements of the AM Process (2020-2024)

D1.3.2.1 Condition-based Risk Management Update

In 2017, Toronto Hydro transitioned from the ACA methodology originally adopted in 2008 to an ACA model that provides more accurate and comprehensive condition-based analytics, and that better supports expenditure planning over longer time horizons.

The model that Toronto Hydro has implemented is the Condition-Based Risk Management ("CBRM") methodology, known in the United Kingdom (where it originated) as the Common Network Asset Indices Methodology ("CNAIM"). This methodology was developed and adopted by the major utilities in the United Kingdom in collaboration with the regulator, Ofgem. In terms of the functional outputs of the model, the methodology provides a reliable and detailed calculation of condition score for every applicable asset based on the most recent inspection information and an asset class's unique requirements. The methodology further facilitates the ability to project and calculate future health scores for assets which provides information on asset demographics that can be used to evaluate proposed investment strategies over longer-term periods. Since the establishment of the methodology in 2017, the health score calculation and future forecasting methodology has remained largely consistent, with certain targeted adjustments to reflect inspection program changes and to ensure the model is producing results that are aligned with field observations.

This model provides incremental benefits at the strategic level by facilitating projections of asset condition demographics by asset class. This allows Toronto Hydro to assess the current and future condition profiles of an asset class to better calibrate the level of investment necessary to either maintain or improve the amount of failure risk associated with its aging, condition and deteriorating asset base over time.

Toronto Hydro is currently working to introduce a risk-based value framework into its EAIP tool. Under the umbrella of this initiative, Toronto Hydro is in the process of developing and implementing a fully quantified risk value for each unique asset based in part on the core principles and methodologies of the CBRM framework. Arriving at a quantified risk value involves multiplying the Probably of Failure for an asset – which is derived from its Asset Health Score (or age when condition is not available) – by a Consequence of Failure (also know as its "criticality") which can be expressed in dollars. Toronto Hydro is currently developing Consequence of Failure models that will include impacts such as financial, safety, environmental and reliability outcomes. Toronto Hydro is currently on track to implement this value framework in time for the beginning of the 2025-2029 period.

Appendix A to section D3 of the DSP provides a detailed discussion of recent and ongoing enhancements to the model, and condition results by major asset class.

D1.3.2.2 Data Consolidation: Data Warehousing for Engineering Analytics

Toronto Hydro is currently performing improvements to its engineering data warehouse to streamline data access, and perform "big data" calculations that can support planning and system investment strategies. In parallel, the utility is further leveraging data blending and analytics software, and has integrated software into business processes to improve productivity and drive new insights.

As part of this effort, Toronto Hydro is implementing an Engineering Asset Investment Planning ("EAIP") solution to streamline the optimization of Toronto Hydro's annual portfolio of projects and long-term asset investment plans. The solution will allow Toronto Hydro to implement and adopt a consistent and robust measure of value and risk for improved asset management decision-making.

The implementation of EAIP will provide an efficient interface for project creation and integrates components of both the scope and work package. Moreover, the EAIP solution provides a centralized and standardized repository for asset data, business cases, project outcomes, work packages and integrates with other information sources like the utility's ERP and GIS systems.

As part of the Asset Analytics & Decision-making portfolio within the Grid Modernization Roadmap, Toronto Hydro plans to integrate relevant enterprise systems into a fully harmonized asset data registry. Toronto Hydro also plans to accelerate the development and implementation of predictive and prescriptive analytics within asset management and grid operations. The portfolio is discussed in detail in Exhibit 2B, Section D5.

D2 Overview of Distribution Assets

D2.1 Distribution Service Area and Trends

Toronto Hydro is one of the largest municipal electrical distribution utilities in North America, serving the City of Toronto – Canada's largest city. The city is bounded by Lake Ontario to the South, Steeles Avenue to the North, Mississauga (mainly Highway 427) to the West, and Scarborough/Pickering Townline to the East. As shown in Figure 1 below, Toronto Hydro's service territory can be divided into two geographic areas: (i) an urban centre in downtown Toronto with a high customer density and a large financial and entertainment district; and (ii) a suburban area around downtown Toronto with a lower customer density, which is colloquially referred to as the "Horseshoe" area.

Figure 1: Areas of the Toronto Hydro Distribution System

The following subsections discuss the characteristics of Toronto Hydro's service territory, including its customers and load growth profiles, climate and weather, and economic profile. Section D2.2 provides a detailed description of the utility's asset demographics, system configurations, and asset condition, and Section D2.3 provides a summary of system utilization.

D2.1.1 Customer and Load Growth

Toronto Hydro's distribution system supplies approximately 790,000 customers with a peak load of 5,191 MVA as of 2022. Toronto Hydro has been experiencing steady customer growth for many years, as shown in Figure 2.

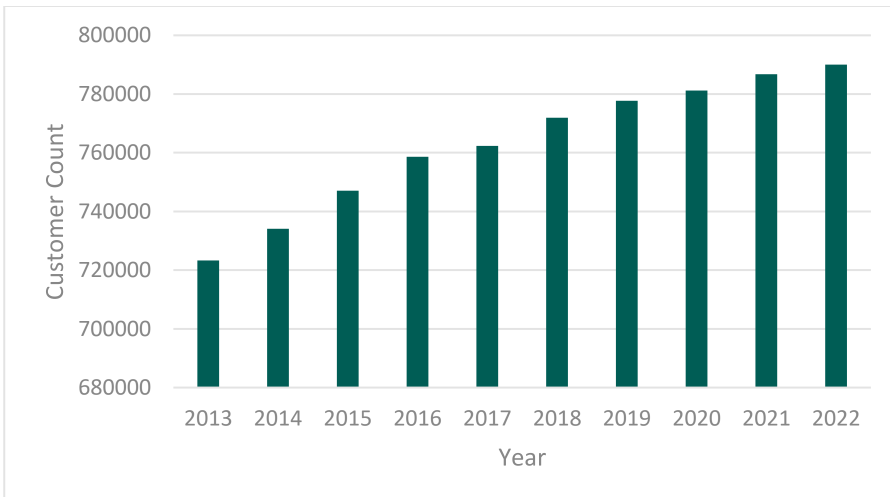


Figure 2: Historical Toronto Hydro Customer Counts

Despite steady customer and population growth, overall system peak load has remained relatively steady in recent years at approximately 5,000 MVA, as shown in Figure 3. It is important to note that system peak load varies with temperature.

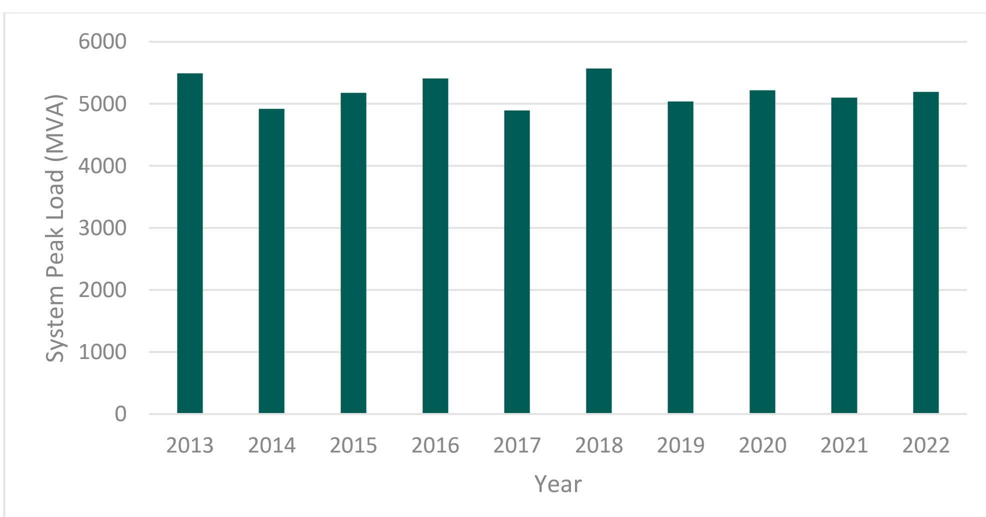


Figure 3: Historical Toronto Hydro System Peak Loading

Toronto is one of the fastest growing cities in North America with an additional 500,000 people expected by 2030. [1,2] Since 2015, the city of Toronto has led the crane count in the United States and Canada.[3] As of Q1 2023, Toronto has 238 cranes of which 58 percent are residential buildings and 29 percent are commercial/mixed use (see Figure 4 below).

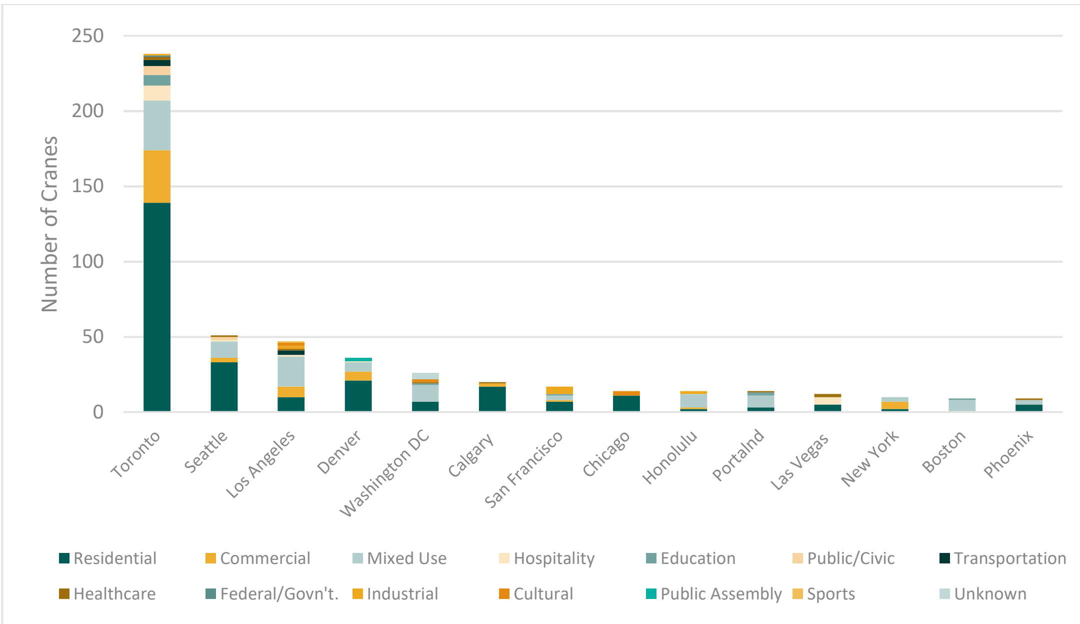


Figure 4: RLB Crane Index - Q1 2023

The city continues to experience highly concentrated load growth in certain pockets of the city due to a high number of large building developments. This concentrated growth occurs mainly in the downtown area, but also along major transit corridors such as Yonge Street and Sheppard Avenue as shown in Figure 5. Consequently, this growth is pushing certain distribution and station equipment

[1] Centre for Urban Research and Land Development, Toronto Second Fastest Growing Metropolitan Area, City of Toronto the Fastest Growing Central City, in the United States/Canada in 2022, https://www.torontomu.ca/centre-urban-research-land-development/blog/blogentry7311/, Research found City of Toronto to be the fastest growing central city in the United States and Canada.

[2] Toronto Public Health, Toronto's Population Health Profile: insight into the health of our city https://www.toronto.ca/wp-content/uploads/2023/02/940f-Torontos-Population-Health-Profile-2023.pdf, Toronto's population increased by 2.3 percent between 2016 and 2021. By 2031, Toronto's population is expected to exceed 3.4 million people. 2021: 2,794,356 2031 Projection: 3,460,604.

[3] Urbanize Toronto, RLB Crane Index Records 238 Cranes in Toronto During Q1 2023, https://toronto.urbanize.city/post/rlb-crane-index-records-238-cranes-toronto-during-q1-2023#:~:text=According%20to%20the%20latest%20report,%2C%20Chicago%20(14)%2C%20Honolulu

to capacity. Infrastructure renewal and upgrades are required in these areas to support growth while maintaining reliability and system resiliency.

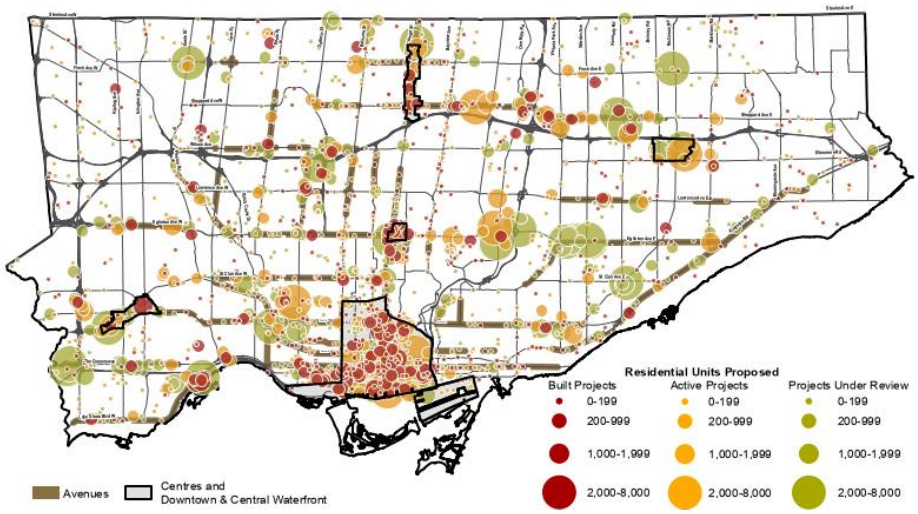


Figure 5:[4] Growth Nodes within the City of Toronto

Toronto is also Canada's largest data centre market.[5] With respect to data centre connections, Toronto Hydro connected approximately 102 MW of incremental demand load during the 2020-2024 period, and approximately 198 MW is forecasted to be connected during the 2025-2029 period.[6] According to Toronto Hydro's Peak Demand forecast, by 2031, data centres and EVs will contribute approximately 10 percent of the overall peak demand of the downtown region.[7]

Going forward, Toronto Hydro expects growing pressure on the distribution system, amplified by the accelerated adoption of Electric Vehicles ("EVs") and growth in electrified heating. The utility foresees these electrification drivers pushing the overall system peak higher in the future as well.

Growth in Electric Vehicles

Electric Vehicle ('EV') adoption is accelerating across the globe, driven in part by policies intended to reduce greenhouse gas emissions from the transportation sector. The Canadian government has

[4] City of Toronto, Development Pipeline 2022 Q2 (February 2023), https://www.toronto.ca/wp-content/uploads/2023/02/92b5-CityPlanning-Development-Pipeline-2022-Q2.pdf
[5] Cushman & Wakefield, 2022 Global Data Center Market Comparison, (2022), https://www.cushmanwakefield.com/en/insights/global-data-center-market-comparison
[6] Exhibit 2B, Section E5.1
[7] Exhibit 2B, Section D4.

announced a new light-duty vehicle sales goal targeting a 100 percent share for EVs by 2035, including interim targets of at least 20 percent by 2026 and 60 percent by 2030. To support its goals, the Government of Canada will invest $1.7 billion to extend incentives for light-duty vehicles, $400 million for charging stations, and $547.5 million for a purchase incentive program for medium-and heavy-duty vehicles.[8] The province of Ontario is the third largest vehicle-producing jurisdiction in North America.[9] Several automotive plants in Ontario are being prepared to build EVs and related components.[10]

Figure 6 shows that the number of new EV registrations in Ontario has been increasing over the last six years. For comparison, the total number of vehicle registration of all fuel types in Ontario have seen a steady decrease from 798,500 in 2018 to 594,500 in 2022. Toronto Hydro's Future Energy Scenarios ("FES") modelling results provide a range of plausible EV adoption rates in Toronto out to 2050 for three scenarios: Low, Medium and High EV adoption scenario. According to FES modelling, the number of Battery Electric Vehicles is projected to grow to approximately 1.8 million by 2050 in the Medium and High scenarios, and approximately 1.2 million by 2050 in the Low scenario. These results are discussed in the Future Energy Scenarios report.[11]

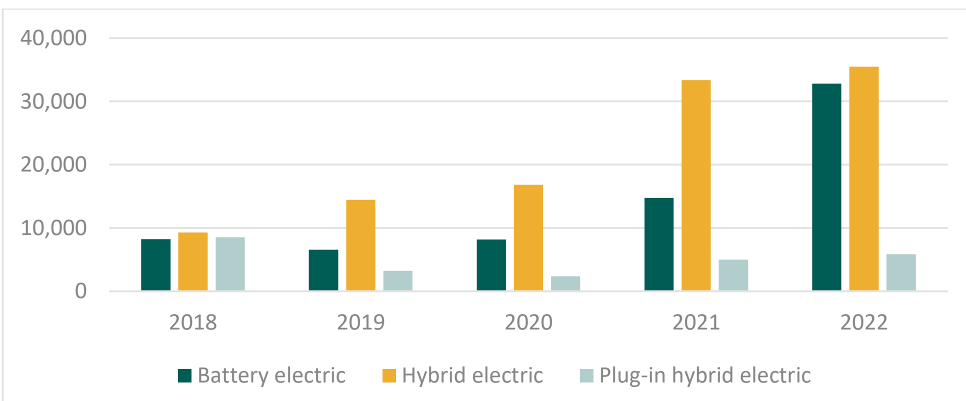


Figure 6:[12] Number of New Vehicle Registrations by Fuel Type in Ontario, as of Q4 2022

[8] Government of Canada, 2020 Emission Reduction Plan – Sector-by-sector overview (2022), https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030/sector-overview.html#sector6
[9] Invest Ontario, Automotive (2022), https://www.investontario.ca/automotive#intro
[10] Canadian Metalworking, Canada jumps into electric vehicle industry (2021) https://www.canadianmetalworking.com/canadianmetalworking/article/madeincanada/canada-jumps-into-electric-vehicle-industry.
[11] Exhibit 2B, Section D4, Appendix B.
[12] Statistics Canada, New Motor Vehicle Registrations (2023), https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2010002401

Growth in Electrified Heating

Heat pumps are an energy-efficient alternative to building heating and cooling systems. The adoption of heat pumps will transition gas and other home heating systems to use electricity. The transition of homes and buildings from natural gas furnaces to heat pumps is a key part of the City's TransformTO Net Zero Strategy.[13]

The Government of Canada has introduced incentives such as the Greener Home Grant, which grants up to $5,000 towards heat pumps and other energy-efficiency measures. In the City of Toronto Climate Change Perceptions Research, 44 percent of homeowners in Toronto say that they are likely to install an air-source heat pump. Figure 7 illustrates the market share of heat pumps in residential sector heating systems has been increasing in recent years. FES modelling explored uptake of electric heat pumps rates, which is discussed in the Future Energy Scenarios report.[14] According to the FES report, widespread uptake of heat pumps, along with technologies such as electric vehicles, are expected to be primary drivers of increases in peak demand and shifting of network peak from summer to winter in the 2030s.

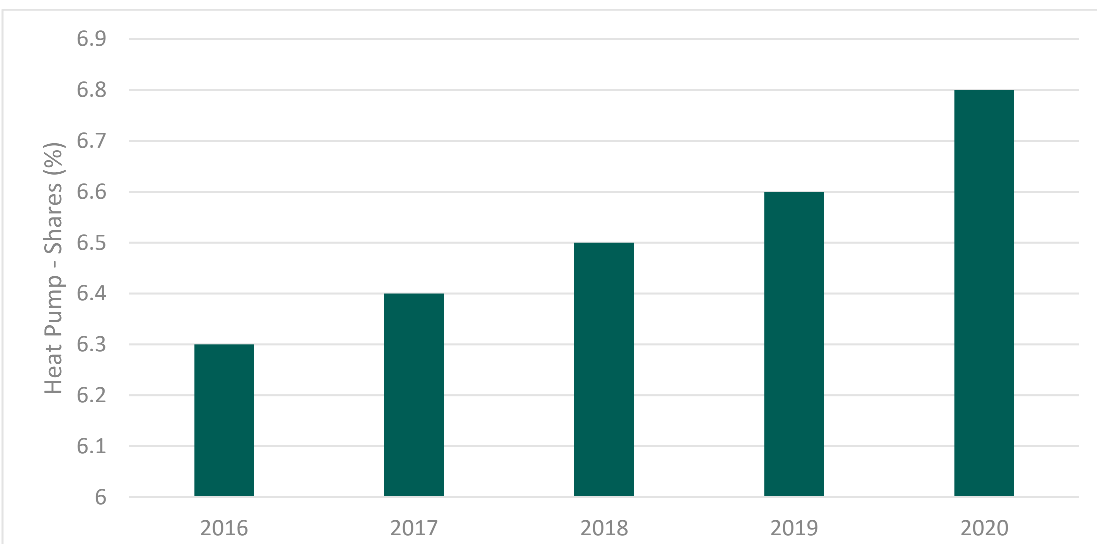


Figure 7:[15] Market Share of Heat Pumps in Residential Sector Heating System in Ontario

[13] City of Toronto, 2021 Net Zero Existing Building Strategy, (2022), https://www.toronto.ca/legdocs/mmis/2021/ie/bgrd/backgroundfile-168402.pdf
[14] *Supra* note 10, Section 4.2.
[15] Natural Resources Canada, Comprehensive Energy Use Database, (2023), Table 21, https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=on&rn=21&page=0

To keep pace with the growing city and ensure appropriate distribution system capacity, especially in order to support electrification, the utility plans to continue actively investing in capacity through the following programs, further described in Section E:

- Customer Connections (Section E5.1);
- Load Demand (Section E5.3);
- Generation Protection Monitoring & Control (Section E5.5);
- Non-Wires Alternatives (Section E7.2); and
- Stations Expansion (Section E7.4).

The utility's complimentary Grid Modernization Strategy is also central to cost-effectively maintaining reliability and improving resiliency in the face of accelerating growth in peak demand.[16]

D2.1.2 Climate and Weather

Climate change is a significant factor influencing Toronto Hydro's planning and operations. Scientists worldwide overwhelmingly agree that the planet is warming. By the year 2050, Toronto's climate is forecasted to be significantly different than the already changing climate seen today. For example, in Toronto, daily maximum temperatures of 25°C are expected to occur 110 times per year as opposed to 87 times per year currently.[17] A warmer climate will also allow the atmosphere to hold more moisture, which is expected to lead to more frequent and severe extreme weather events. These extreme events can cause major disruptions to Toronto Hydro's distribution system.

In addition to extreme weather events, Toronto experiences a wide range of weather conditions that may not be classified as extreme, but nevertheless have the potential to adversely affect the distribution system at various times during the year. Weather conditions of high heat, high winds, heavy rainfall, and heavy snowfall have the potential to cause major system damage and extensive outages. Not only are these weather conditions projected to occur more frequently and with greater severity in the future due to climate change, but trends from the past 25 years suggest that these changes are already affecting the system. Figure 8 below contains two charts depicting cumulative rainfall and the number of high wind days (i.e. with wind gusts exceeding 70 kilometres per hour) in Toronto over the past 25 years. In both cases it is observed that there is an increasing trendline over

[16] Exhibit 2B, Section D5.
[17] Toronto Hydro engaged Stantec to update its Climate Change Vulnerability Assessment, which is filed at Exhibit 2B, Section D2, Appendix A.

the period. With respect to high wind days, an even steeper increase has been observed, and seven of the 10 years with the greatest number of days of wind gusts above 70 kilometres per hour have occurred in the last 10 years (these years are highlighted in orange).

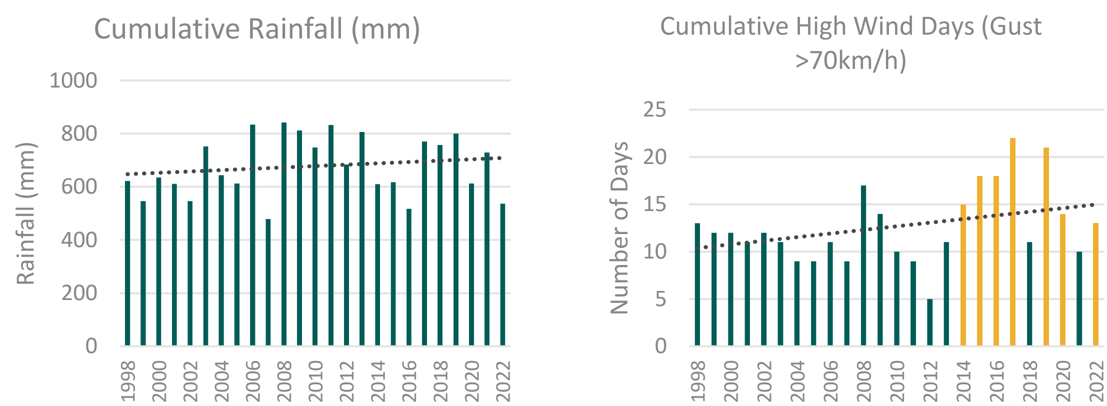


Figure 8: [18]Cumulative Rainfall (left) and Number of High Wind Days (right) in Toronto:

These trends are expected to continue through the 2030s and 2050s with the frequency of extreme rainfall events of 100 mm in less than 1-day antecedent increasing by 11 percent and 20 percent respectively. In terms of high winds, climate projections show that 10-year wind speeds are to increase by 0.7 percent and 2.7 percent in the 2030s and 2050s respectively.[19]

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

Parts of the underground system are sensitive to significant rainfall, and in particular flooding, while the overhead system in general is sensitive to high winds, freezing rain and wet snow events resulting in damage and outages (e.g. from vegetation impact in proximity to overhead lines). In extreme

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

cases, broken trees and the weight of ice accretions bring lines, poles and associated equipment to the ground.

The above-mentioned reliability risks are significant, as evidenced by an event that occurred on May 21, 2022. A major storm with wind gusts as high as 120 kilometres per hour swept through Toronto Hydro's service territory. These extreme winds caused substantial damage to vegetation, which in turn damaged overhead distribution wires and equipment. Approximately 142,000 customers (18 percent of Toronto Hydro's total customer base) were without power during this event. Similarly, four weather-related major events occurred during April to July of 2018 due to wind storms and freezing rain. The events caused 382,286 Customers Interrupted and 1,173,338 Customer Hours Interrupted (discussed in Exhibit 2B, Section C).

To better understand the risks related to increases in extreme and severe weather due to climate change, in June 2015, Toronto Hydro completed a vulnerability assessment following Engineers Canada's Public Infrastructure Engineering Vulnerability Committee ("PIEVC") protocol.[20] The assessment identified areas of vulnerability to Toronto Hydro's infrastructure as a result of climate change. Following this study, a climate change adaptation road map was developed, along with initiatives relating to climate data validation, review of equipment specifications, and review of the load forecasting model.

In 2022, Toronto Hydro updated the 2015 study to identify if any further work is required to update the adaptation measures.[21] The study utilized updated climate projection data from the 6th Coupled Model Intercomparison Project (CMIP6), along with IPCC's 6th Assessment Report (AR6) in 2021, to estimate climate parameter probabilities. These probabilities were then assessed to determine the materiality by recalculating risk scores over the study period (from 2022 to 2050) following the PIEVC protocol. The results of the study provided that two climate parameters had probability changes as follows:

Climate Parameter	Threshold	Frequency (2030s)	Probability (Study Period)	Probability Score (Study Period)	Probability Score Change (2022-2015)
Daily Maximum Temperatures	Days > 40°C	0.08 (0 - 0.1)	90%	6	Decrease (-1)
Ice Storm/ Freezing Rain	25 mm ≈ 12.5 mm radial	-2.2% in 1/20yr ice accretion	96%	6	Decrease (-1)

[20] EB-2018-0165, Exhibit 2B, Section D, Appendix D.
[21] *Supra* note 16.

For each of the above climate parameters, an assessment was completed to determine how these changes in probability impacted the infrastructure asset classes, similar to the 2015 report. The following table provides the results:

Climate Parameter	Threshold	Study Report Year	Number of Interactions by Risk Class		
			High	Medium	Low
Daily Maximum Temperature	40°C	2015	10	23	1
		2022	0	33	1
Ice Storm / Freezing Rain	25 mm ≈ 12.5 mm radial	2015	18	5	9
		2022	5	18	9

Each combination of infrastructure asset class and climate parameter is referred to as an 'interaction'. The updated probabilities resulted in material changes to the risk scores for 23 separate interactions (10 from daily maximum temperatures greater than 40°C and 13 from Ice Storms/Freezing Rain greater than 25 mm).

Although the results observed a decrease in risk scores for these 23 interactions, given the uncertain nature of the climate projection data, the recommendation was to not relax any adaptation measures associated with extreme heat or freezing rain events from the 2015 study.

Existing codes, standards, and regulations were developed with regard to historical weather data and do not always account for ongoing and future changes to the climate. In efforts to close this gap, Toronto Hydro now utilizes climate data projections for temperature, rainfall, and freezing rain in its equipment specifications and station load forecasting. Further, Toronto Hydro reviewed and updated major equipment specifications in 2016 to adapt to climate change, including:

- Revisions to submersible transformer specifications to require stainless steel construction and testing of the equipment's ability to withstand fully flooded conditions;
- Replacement of air-vented, padmounted switches with more robust designs; and
- Adoption of breakaway links in tree-covered areas for residential customers with overhead service connections, intended to facilitate faster restoration after extreme weather and prevent damage to customer-owned service masts.

In February 2023, CSA issued changes to it's Underground and Overhead Systems Standards related to Climate Change Adaptation. Toronto Hydro strives to meet and surpass these new requirements. Some impacts to Toronto Hydro design considerations include:

- Modification of standard pole loading analysis to accommodate extreme weather events in light of recent CSA updates; and
- Standardization of conversion of submersible transformers to padmounted transformers in residential rebuild projects, in order to mitigate the impacts of flooding.

The following 2025-2029 program activities will contribute to Toronto Hydro's ongoing efforts to renew and enhance its system to increase resiliency, thereby supporting the continued delivery of outcomes expected by existing and future customers:

- As assets are replaced in the Overhead System Renewal program (Exhibit 2B, Section E6.5), Toronto Hydro plans to reconfigure feeders and relocate 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.
- Padmounted transformers will replace existing submersible units as the utility carries out its Underground System Renewal – Horseshoe program (Exhibit 2B, Section E6.2).
- Underground System Renewal – Horseshoe program will replace air-vented padmounted switches with more robust designs to mitigate risk of failure due to ingress of dirt and road contaminants on the live surface.
- The Network System Renewal program will replace end-of-life and deteriorated non-submersible protectors with submersible protectors to protect against flooding.
- The Network Circuit Reconfiguration segment under the Network System Renewal program (Exhibit 2B, Section E6.4) will help the utility improve system restoration capabilities in the event of outages.
- Installation of flood mitigation systems at stations identified as being vulnerable to flooding will occur under the Stations Renewal program (Exhibit 2B, Section E6.6).

In addition to these system hardening measures, Toronto Hydro's Grid Modernization Strategy for 2025-2029 has been developed in part to improve long-term system reliability and resiliency in the face of external pressures from both future increases in system utilization and evolving climate impacts. The strategy focuses on accelerating the deployment of digital field and operational technologies that will enhance the utility's ability to address developing fault conditions in real-time, improve outage restoration capabilities and operational flexibility, and lay the groundwork for widescale grid automation beginning in 2030. Key investments include the deployment of technologies that will enhance real-time system observability (e.g. next generation smart meters;

overhead and underground line sensors; network condition monitoring technologies), enhance system controllability (e.g. SCADA-enabled switches and reclosers); and enable integrated and increasingly predictive/automated control of the distribution system (e.g. Advanced Distribution Management System or "ADMS"). For more information on the Grid Modernization Strategy, please refer to Exhibit 2B, Section D5.

Toronto Hydro continues to be a partner of the City of Toronto in planning and preparing for the effects of climate change.

D2.1.3 Economic Profile

The City of Toronto is Canada's economic and financial hub. It is home to the Toronto Stock Exchange, as well as the headquarters of five of the nation's largest banks. Toronto accounts for approximately 20 percent of Canada's Gross Domestic Product ("GDP"). Its GDP growth has significantly outpaced the national average over the 2015 to 2019 period.[22] The city is the second largest financial service centre in North America.[23]

Toronto also has a diverse industrial and commercial base comprised of 14 key sectors including aerospace, design (e.g. fashion, interior), financial services, education, life sciences, technology, food, entertainment, and tourism.[24] The importance of Toronto's economy highlights the necessity of sufficient investments to ensure the delivery of value for distribution customers and to prepare for technology driven change.

Like many regions across the country and the world, Toronto's economy has recently faced significant inflationary pressures. Figure 9 shows the annual change in Consumer Price Index ("CPI") over the past ten years for the City of Toronto, Province of Ontario and Canada. CPI represents changes in prices as experienced by consumers. This figure illustrates the significant increases to CPI in recent years.

[22] Statistics Canada, Gross Domestic Product (GDP) at basic prices (2022), https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=3610046801
[23] City of Toronto, Business & Economy, Strong Economy, https://www.toronto.ca/business-economy/invest-in-toronto/strong-economy/
[24] City of Toronto, Business & Economy, https://www.toronto.ca/business-economy/industry-sector-support/

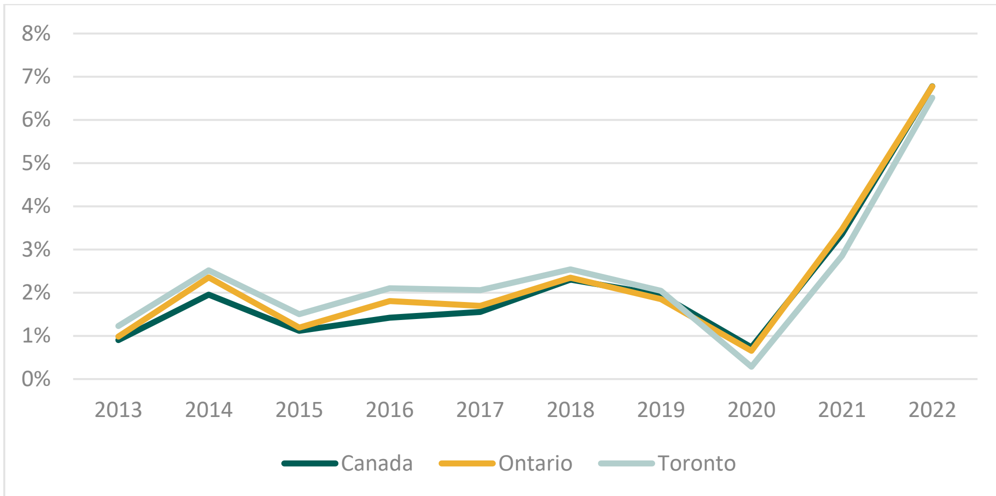


Figure 9: [25]Annual change in CPI over the past ten-year period

Similarly, Building Construction Price Indexes ("BCPI") provide change in prices over time that contractors charge to construct a range of new commercial, institutional, industrial and residential buildings. BCPI for non-residential buildings is relevant to Toronto Hydro's costs and has risen significantly in recent years. Figure 10 illustrates the average increase in BCPI for non-residential buildings for the City of Toronto.

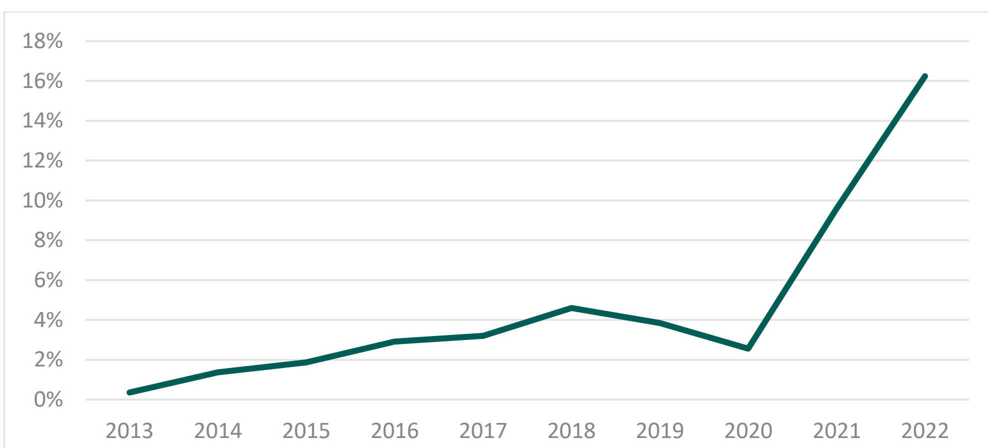
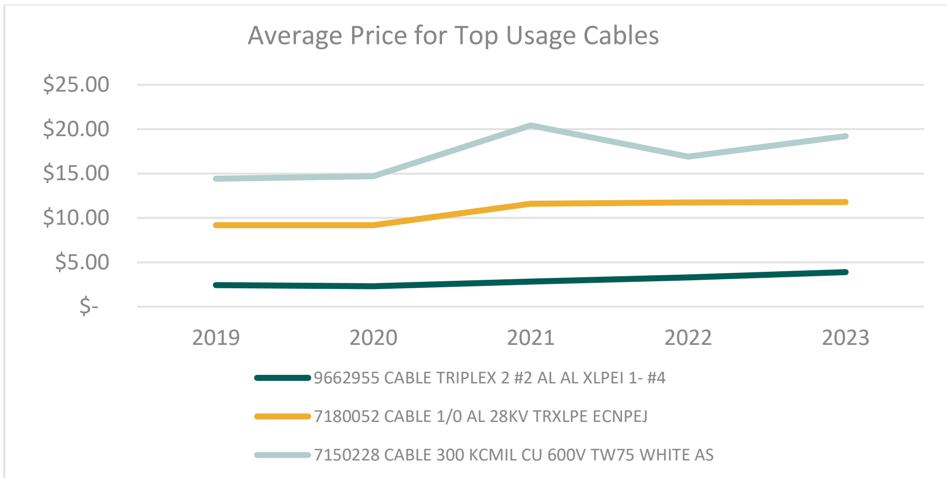


Figure 10: [26] Annual change in BCPI for non-residential buildings over the past ten-year period

[25] Statistics Canada, Table 18-10-0005-01 Consumer Price Index , annual average (2023), https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000501
[26] Statistics Canada, Table 18-10-0276-01 Building Contruction Price Indexes (2023), https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810027601

In addition to increases in CPI and BCPI for non-residential buildings, Toronto Hydro also faces increasing commodity prices. Figure 11 illustrates the average price for some top usage equipment in Toronto Hydro.



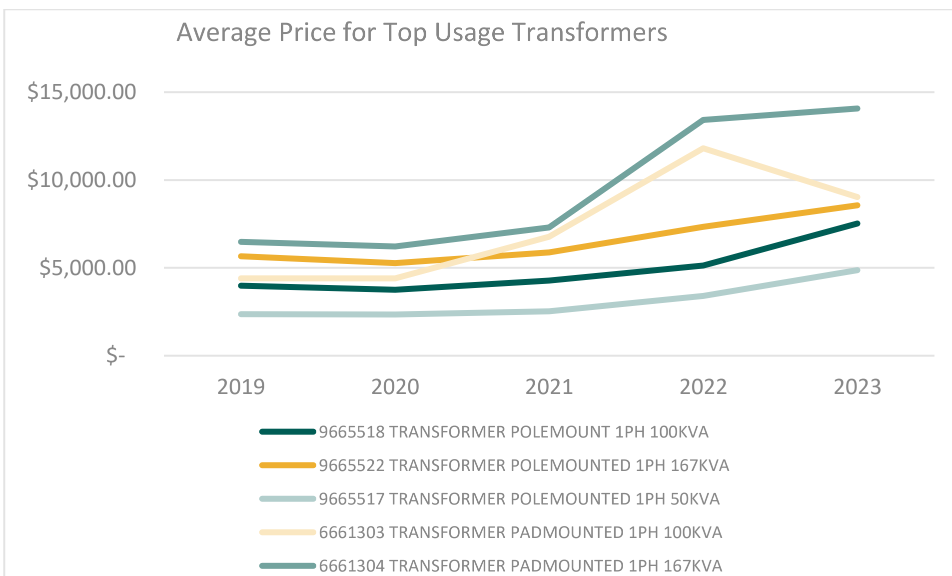


Figure 11: Average price for some top usage equipment in Toronto Hydro

D2.1.4 Toronto Hydro's Evolving Role in the City of Toronto

The role that Toronto Hydro plays in its service territory is evolving as new technologies emerge. In many cases, local and provincial policy imperatives aim to accelerate the uptake of new energy related technologies such as distributed generation and energy resources, and power quality, reliability and resiliency solutions.

One example is the City of Toronto's climate change action plan and long-term vision. A key pillar of this plan is the *TransformTO* Net Zero Strategy,[27] which identifies how the City plans to reduce greenhouse gas emissions, improve health, grow the economy, and improve social equity. One of the major commitments of this plan is for 100 percent of vehicles in Toronto to use low-carbon energy by 2040. As part of achieving this goal, the City has made climate related investments for water, solid waste and parking. In addition, the City is making significant capital investments in the TTC, which includes vehicles such as buses, streetcars and subway cars.[28]

Toronto Hydro prepared a Climate Action Plan to support the City's objectives. The Climate Action Plan encompassed the areas of EV charging infrastructure, modernization of streetlighting, building electrification and energy efficiency, renewable energy, and energy storage.[29] Toronto Hydro has also established a target of achieving net zero for its own operations by 2040.

There are three climate action opportunities Toronto Hydro is pursuing to reach its objectives. Firstly, following the planning principles and forecasting approaches outlined in Section D4 of the DSP, Toronto Hydro plans to expand its existing electricity distribution business to build a grid that is capable of supporting the realization of the City's Net Zero Strategy. The second opportunity is for Toronto Hydro to create a new, non-rate-regulated Climate Advisory Services line of business to support the City's Net Zero Strategy by facilitating and stimulating the growth of emerging local cleantech markets. The third opportunity is pursuing modernization of outdoor lighting within the utility's existing unregulated streetlighting company.

Provincial and federal policy targeting greenhouse gas reductions is also a driver of technological change. Provincial energy policy, such as the Net Metering program, supports and incentivizes the connection of renewable energy projects to the local distribution system. As of the end of 2022, Toronto Hydro has connected 2,424 unique distributed energy resource ("DER") projects to its distribution grid, totaling approximately 305 MW of generation capacity.[30] As discussed in Section

[27] City of Toronto, TransformTO Net Zero Strategy, https://www.toronto.ca/legdocs/mmis/2021/ie/bgrd/backgroundfile-173758.pdf
[28] See Exhibit 2B, Section E.
[29] Toronto Hydro, Climate Action Plan, https://www.torontohydro.com/documents/20143/74105431/climate-action-plan.pdf/8fe4406c-7675-76a7-00c9-c0c4e58ae6df?t=1638298942821
[30] Exhibit 2B, Section E5.1.

E3, Toronto Hydro anticipates steady growth in generation connections going forward and is planning to invest in necessary renewable enabling improvements, including monitoring and control technologies, and energy storage systems to facilitate this growth during the 2025-2029 rate period.

D2.2 System Demographics and Characteristics

Toronto Hydro's distribution system consists of a mix of overhead, underground, network, and stations infrastructure. This infrastructure operates at voltages of 27.6 kV, 13.8 kV, and 4.16 kV, and includes approximately 61,000 distribution transformers, 17,000 primary switches, 15,600 kilometres of overhead conductors, and 13,800 kilometres of underground cables as of 2022. Unless otherwise mentioned, asset demographic information provided herein is as of 2022.

The following sections provide details on these sub-systems and how each sub-system relates to Toronto Hydro's major asset management objectives. As discussed in Exhibit 2B, Section D3, Toronto Hydro manages its distribution infrastructure and plans capital investments and maintenance to achieve asset performance objectives, specifically, the attainment of applicable outcomes summarized in Section D1, and further detailed in Sections C and E2 of the DSP.

The following table and accompanying explanations introduce Toronto Hydro's sub-systems through the lens of a core subset of risk related asset management performance measures, all of which relate directly or indirectly to Toronto Hydro's outcomes.

Table 1: Asset Management Performance Indicators by System Type

System	**Oil Deficiencies** (Number of assets)	**Priority Deficiencies** (Number assigned)	**Customer Hours of Interruption** due to Defective Equipment	**Customer Interruptions** due to Defective Equipment	**Condition** [31] (Percentage of Assets in HI4 or HI5)	**Oil Containing PCBs** (Number of assets with oil containing or at risk of containing PCB)	**Age** (Percentage of Assets past Useful Life)	**Legacy Assets**
	Lagging Indicator of Performance				**Leading Indicator of Performance**			
Overhead	11 (3%)	3,074 *(24%)*	68,312 *(27%)*	117,175 *(33%)*	8.8%	3,076 (57%)	16%	2756 Box Construction Poles 6832 Customers Served by Rear Lot 502 km of 4.16 kV conductor
Underground	298 (88%)	8,955 *(71%)*	170,290 *(68%)*	230,661 *(64%)*	3.3%	2,278 (42%)	23%	721 km of Direct-Buried Cable 140 Transclosures[32] 985 km of PILC[33] Cable 176 km AILC[34] Cables 202 km of 4.16 kV cable
Network	21 (6%)	0 (0%)	0 *(0%)*	0 *(0%)*	4.0%	66 (1%)	23%	533 Non-Submersible Network Units 651 vaults without communication
Stations	8 (2%)	560 (4%)	10,636 *(4%)*	9,652 *(3%)*	3.1%	-	43%	346 legacy breakers at TSs[35] 558 legacy breakers at MSs[36]
Total	**338 *(100%)***	**12,589 *(100%)***	**249,238 *(100%)***	**357,488 *(100%)***	**7.1%**	**5,420 (100%)**	**25.2%**	-

Notes: All figures are 2022 year-end actuals, unless otherwise noted.

[31] See Exhibit 2B, Section D3, Appendix A for summary of results and details on updates to Toronto Hydro's Asset Condition Assessment.
[32] As a result of data improvement efforts, the transclosure population was updated to 140.
[33] Paper Insulated Lead Covered ("PILC") cable.
[34] Asbestos Insulated Lead-Covered ("AILC") cable.
[35] Transformer Station ("TS").
[36] Municipal Station ("MS").

- **Oil Deficiencies:** An oil deficiency is any observation related to oil (e.g. dried oil, oil leak) made during planned asset inspections. These are reported by inspectors when inspecting equipment and components that are known to or intended to contain oil. Oil deficiencies are an indicator of the likelihood of oil spills. The primary driver for this metric is to protect the environment from oil spills and to adhere to federal, provincial, and municipal legislation, regulations, and by-laws pertaining to the release of oil into the environment. Toronto Hydro strives to achieve zero oil leaks into the environment. Programs that contribute to the management of this measure are Preventative and Predictive Maintenance programs for oil filled equipment,[37] and capital programs that replace deteriorating oil filled equipment, including Underground System Renewal,[38] and Reactive and Corrective Capital (Section E6.7).[39]

- **Priority Deficiencies**: Toronto Hydro defines "priority deficiencies" as the subset of all equipment deficiencies that require intervention on a reactive or corrective basis. Between 2020 to 2022, Toronto Hydro identified around 45,000 deficiencies each year through planned inspections, responding to equipment failures and power interruptions, or through the course of day-to-day work. The total number of deficiencies are higher compared to the last rate application partially due to the inclusion of deficiencies corrected on site, which were not counted in the previous DSP. Priority deficiencies are deficiencies that pose a high risk to reliability, safety, or the environment and are assigned as priority 1 (P1), priority 2 (P2), or priority 3 (P3) for the purposes of addressing the deficiency. Each category corresponds to a level of risk (with P1 being the highest risk) and a timeline for repairing the deficiency or replacing the asset. Toronto Hydro has various programs (including Reactive and Corrective Capital, Corrective Maintenance, and Emergency Response) to address asset deficiencies, some of which have already resulted in asset failure.[40] Given the risks, timely and effective responses to priority deficiencies are non-discretionary and must be taken over short time horizons (i.e. less than six months). Identifying and responding to priority deficiencies in a timely manner is critical to meeting the utility's performance objectives for key outcomes such as SAIDI and SAIFI, and the utility's safety and environmental objectives.

[37] Exhibit 4, Tab 2, Schedules 1, 2, and 3.
[38] Exhibit 2B, Sections E6.2 and E6.3.
[39] Exhibit 2B, Sections E6.7.
[40] Exhibit 2B, Section E6.7 and Exhibit 4, Tab 2, Schedule 4-5.

The volume of corrective work requests has been increasing in recent years which has resulted in a growing backlog of P3 deficiencies that need to be addressed. This increase can be attributed to deteriorating asset condition and asset-related safety risks to crews or the general public, in addition to enhanced inspection forms and the introduction of new inspections. This has resulted in approximately $20 million worth of backlog for lower priority work requests, which is expected to grow. To help manage this risk, the corrective work requests in the backlog have been further prioritized by level of risk within P3 priority, and by the primary and secondary impact of the deficiency.[41]

- **Customer Hours of Interruption ("CHI") and Customer Interruptions ("CI") (i.e. Outages)**: CHI and CI are measures of outage duration and frequency, scaled by the number of customers affected by each outage. Toronto Hydro uses this type of historical reliability data to identify priority project areas across all of its reliability-related programs, and to develop and pace investment program spending in order to improve key outcomes that the utility reports including SAIDI and SAIFI.

- **Assets with Material Deterioration or at End of Serviceable Life**: As described in detail in Section D3 and associated appendices, Toronto Hydro's asset condition assessment ("ACA") methodology assigns health scores to assets based on observable condition variables, and categorizes these scores within five health index bands ("HI1" to "HI5"). Asset condition demographics are a strong predictor of future asset performance. Over the long-term, Toronto Hydro is focused on managing the number of assets in the HI3 ("moderate deterioration") to HI5 ("end of serviceable life") bands, with a particular emphasis on preventing significant increases in the most critical HI4 and HI5 bands.

- **PCBs**: Toronto Hydro defines "PCB at-risk equipment" as an asset that: (i) is known to contain oil with greater than 2 ppm concentration of polychlorinated biphenyl ("PCB"); or (ii) has an unknown concentration of PCB and was manufactured in 1985 or earlier (and is therefore at a high risk of containing greater than 2 ppm PCB). This measure excludes cables. Due the toxic and persistent nature of PCBs, Environment Canada's *PCB Regulations*[42] 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

[41] Exhibit 4, Tab 2, Schedule 4.
[42] PCB Regulations, SOR/2008-273, under the *Canadian Environmental Protection Act*, 1999.

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.[43] Toronto Hydro plans to continue its efforts to address PCB at-risk equipment by 2025 through a combination of inspection and testing equipment under its maintenance programs,[44] and through targeted asset replacement in capital programs such as Overhead System Renewal,[45] Underground System Renewal,[46] Network System Renewal,[47] Stations Renewal,[48] and Reactive and Corrective Capital.[49]

- **Age**: Toronto Hydro monitors the percentage of its asset base that has passed useful life or will pass that milestone by the end of the next planning horizon. As a comprehensive indicator of failure risk across the system, this information is used for longer-term planning purposes. As of the end of 2022, Toronto Hydro's percentage of assets past useful life was 25 percent, with an additional 11 percent forecasted to reach expected useful life by the end of 2030, meaning that over a third of the utility's asset base is at or nearing the end of its typical useful life. By managing this measure over the long-term, the utility aims to provide predictability in the performance of key outcomes like reliability and safety for current and future customers, and to provide stability in costs, rates and labour resourcing by not allowing significant backlogs of asset replacement needs to accumulate.

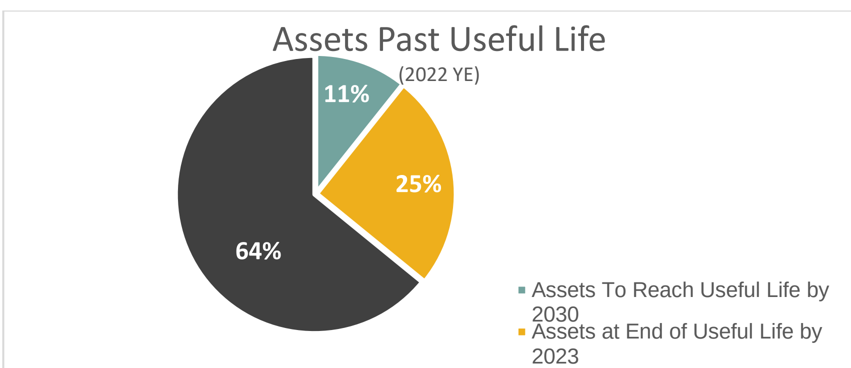


Figure 12: Assets Past Useful Life

[43] Toronto Municipal Code, Chapter 681 – Sewers.
[44] Exhibit 4, Tab 2, Schedules 1-4.
[45] Exhibit 2B Section E6.5.
[46] Exhibit 2B, Sections E6.2 and E6.3.
[47] Exhibit 2B Section 6.4.
[48] Exhibit 2B Section 6.6.
[49] *Supra* note 37.

- **Legacy Assets**: Legacy assets are specific asset types, configurations, or sub-systems that do not meet current Toronto Hydro standards. These assets often feature obsolete components with limited or no supplier or skilled labour support to maintain, repair or replace the assets, and carry elevated reliability, safety, or environmental risks. Additionally, lower voltage parts of Toronto Hydro's system are increasingly obsolete from a design perspective due to their inability to support the high levels of electrification and DER integration that the utility anticipates over the next 15-20 years. One of Toronto Hydro's asset management strategies is to eliminate all high-risk legacy assets within a specific and reasonable timeframe. The specific legacy assets are discussed further in the following sections as part of the overhead, underground, network, and stations systems descriptions. Table 2 above provides an estimate of the remaining volumes of certain key legacy assets across Toronto Hydro's different subsystems. For further details on specific legacy asset replacement and pacing, please see Exhibit 2B, Section E2.

The following sections provide a more detailed view of the overhead, underground, network, and stations sub-systems of Toronto Hydro's distribution system, including the age and condition demographics of the assets, and associated system challenges. Each section provides a further breakdown of how those sub-systems relate to Toronto Hydro's asset management indicators and measures discussed above.

D2.2.1 Overhead Grid System

The overhead system consists of poles, overhead conductors, overhead transformers, overhead switches, and other equipment including lightning arrestors, guying hardware, and wires. All of these assets are placed above ground in areas with sufficient space and clearance from overhead obstructions (e.g. trees and buildings). Advantages of using an overhead system are that it is cost effective and allows for more expeditious fault identification and outage restoration, given that all assets are out in the open and visible to crews. Disadvantages of this system are that it is prone to foreign interference from vehicles, trees, animals, and weather-related outages (i.e. caused by high winds or freezing rain), and requires adequate clearances to operate and maintain.

Figure 13: Overhead Distribution Transformer

The majority of Toronto Hydro's overhead system is operated at 27.6 kV and 13.8 kV, but a subset of the overhead system operates at 4.16 kV. The overhead system consists of approximately 166,500 poles, 7,400 overhead switches, 30,000 overhead transformers, 4,000 circuit-kilometres of overhead primary, and 11,300 circuit-kilometres of overhead secondary conductors as of 2022.

Asset management activities related to the overhead distribution system focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies, managing system performance with respect to reliability and power quality, and asset stewardship over the assets' lifespan.

Figure 14 provides the age demographic distribution of major overhead assets. As of 2022, approximately a quarter of poles are beyond their typical useful life of 45 years. Without any intervention, Toronto Hydro projects that the percentage of poles having reached or exceeded useful life will increase from 24 percent as of 2022 to approximately 30 percent by 2029. Similarly, overhead transformers having reached or exceeded useful life will increase from 14 percent as of 2022 to approximately 25 percent by 2029 and the percentage of overhead switches having reached or exceeded useful life will increase from 40 percent as of 2022 to approximately 68 percent by 2029.

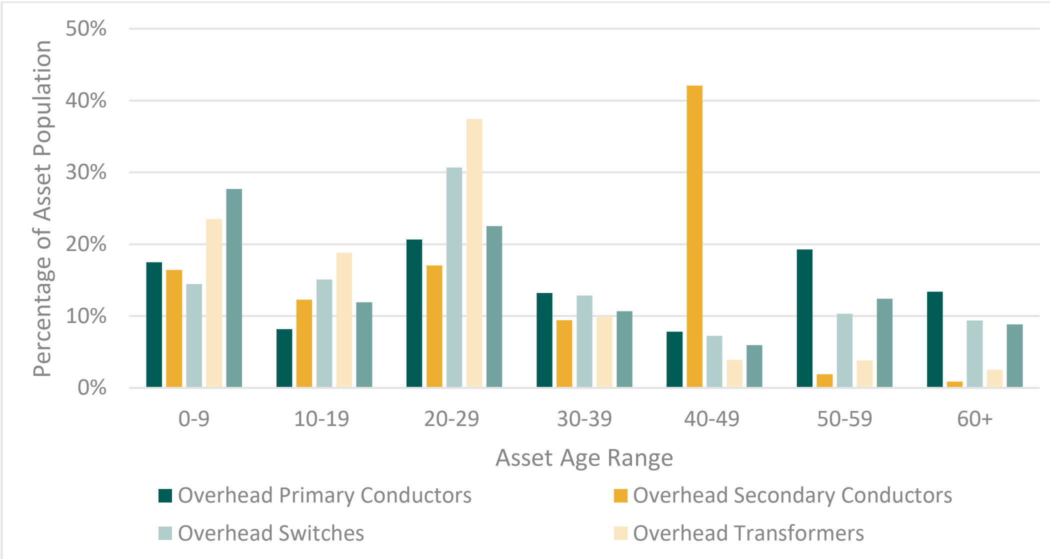


Figure 14: Overhead Assets Age Demographics as of 2022

Wood poles and overhead switches are the two major overhead asset classes for which Toronto Hydro performs an Asset Condition Assessment ("ACA"), as summarized in Figure 10. With respect to wood poles, the ACA showed that approximately 30 percent of Toronto Hydro's wood poles have at least moderate deterioration as of 2022. With over 21,000 wood poles in HI3 condition (i.e. "moderate deterioration"), 8,950 in HI4 condition (i.e. "material deterioration"), and approximately 509 in HI5 condition (i.e. "end of serviceable life"), pole replacement will continue to be a significant driver of both reactive and planned investment through 2029. The need for a continued pole replacement strategy and investment is underscored by the projected rate of deterioration across this asset class over the rate period.[50]

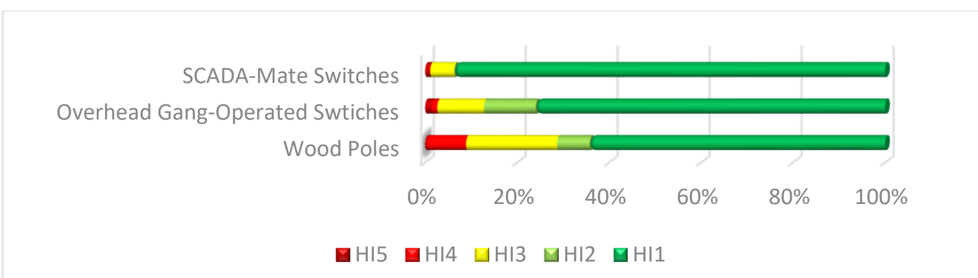


Figure 15: Asset Condition Assessment of Overhead Assets as of 2022

[50] *Supra* note 43.

Other key asset management performance measures that are relevant to the overhead system include:

- **Oil Deficiencies**: Pole top transformers are the only asset type in the overhead system that may exhibit oil deficiencies. During the 2020-2022 period, Toronto Hydro found on average six pole-top transformers with oil deficiencies annually. The Reactive and Corrective Capital program (Section E6.7) will continue to target pole top transformers exhibiting oil deficiencies.

- **Priority Deficiencies:** Overhead assets are susceptible to external interference from animals, insects, adverse weather, and vegetation contacts. These factors accelerate degradation processes and cause damage. From 2019 to 2022, Toronto Hydro issued more than 10,000 work requests to address deficiencies, predominantly for failing or failed overhead assets. In 2022 alone, Toronto Hydro classified 218 P1, 724 P2, and 2,132 P3 priority deficiencies on the overhead system.

- **PCBs**: Pole top transformers are the only asset type in the overhead system that are known to contain PCB contaminated oil. At of the end of 2024, there will be an estimated 500 PCB pole top transformers containing or at risk of containing PCBs remaining on the system. By replacing these assets, predominantly through the Overhead System Renewal program (Section E6.5), Toronto Hydro endeavours to eliminate the risk of PCB-contaminated oil spills by the end of 2025.

D2.2.1.1 Overhead Legacy Equipment

On the overhead system, a major challenge facing Toronto Hydro stems from legacy overhead assets such as porcelain insulators and arrestors, non-standard animal guards, and legacy construction types such as rear lot and box construction. These legacy assets contribute to poor reliability performance, safety risks, and other undesirable outcomes. Capital investment programs that are planned to target and mitigate challenges within the overhead system include: Area Conversions,[51] Overhead System Renewal,[52] and Reactive and Corrective Capital.[53]

1. Obsolete and deteriorating overhead accessories

Overhead accessories include three major categories: insulator hardware, conductors, and animal guards. These assets are interconnected and integrated with transformers, poles, and switches and are vital components of the distribution system.

- **Legacy Insulator Hardware:** Toronto Hydro's legacy insulators are predominately porcelain, which is an insulation material that has been commonly used for switches, lightning arrestors, terminators, and line posts. The failure modes for assets with porcelain insulating material typically involve assets cracking and breaking apart. In some cases, discharge of fragments due to weakening structural integrity of the material could occur as a result of a failure. Porcelain hardware has the potential to fail in a catastrophic manner, releasing porcelain shards which can damage nearby equipment and public property. For example, one porcelain insulator failure incident in Toronto sent shards of porcelain into the balcony of a nearby home, shattering the window of the family room and causing damage to the windshield of a nearby police car. The effects of this porcelain pothead failure can be seen in Figure 16. In general, porcelain material tends to have a high risk of failure due to its tendency for contamination build-up that leads to electrical tracking (i.e. the breakdown of insulation materials, which can lead to faults), and as such, will be replaced with polymeric material.

[51] Exhibit 2B, Section E6.1.
[52] *Supra* note 43.
[53] *Supra* note 37.

Figure 16: Porcelain Pothead Failure

- **Animal Guards:** Existing legacy wildlife protection on Toronto Hydro's overhead distribution system consists of "Guthrie" guard animal protectors. Toronto Hydro is installing newer animal guards with a design that provides an improved physical non-conductive barrier. Figure 17 below shows the difference between "Guthrie" and the new animal guards used by Toronto Hydro to guard against wildlife.

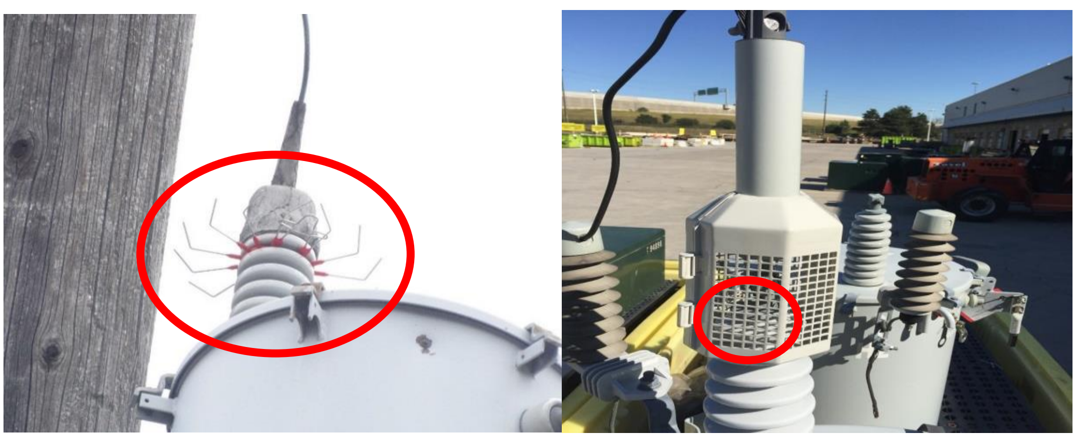


Figure 17: Animal Guards – Guthrie Guard (left), Newer Wildlife Guard (Right)

2. Legacy construction types

- **Rear Lot Construction:** This consists of overhead and underground assets that are installed in the backyard, or rear lot, and are generally operating near or beyond useful life. These assets were installed to serve residential customers in the Horseshoe region of Toronto. Due to accessibility limitations, outages on the rear lot plant tend to be longer in duration. The location of the plant also presents safety risks to customers and employees. Toronto Hydro is continuing to replace rear lot plant with standard, front lot underground circuits as part of the Area Conversions program.[54]

- **Box Construction:** These overhead feeders are located along main streets in the downtown area and serve residential neighborhoods and small commercial customers. The congested, box-like framing of the circuits prevents crews from establishing safe limits of approach to live conductors, which in turn restricts operations and leads to longer power restoration times for customers when compared to modern overhead standards. Toronto Hydro plans to eliminate the remaining box framed poles by 2026 as part of the Area Conversions program (Section E6.1).

D2.2.1.2 Overhead Assets Failure Characteristics

Table 2 below highlights the failure modes and impacts of overhead asset failures.

Table 2: Overhead Asset Failure Modes

Asset	Failure Mode	Effects
Pole Top Transformer	a) Arc flash due to contamination of bushing. b) Corrosion of tank. c) Winding Failure.	a) Causes tracking and can lead to catastrophic failure (e.g. oil fire, spill). b) Causes oil leakage and potential environmental issues. c) Can lead to catastrophic failure (e.g. oil fire, spill).
Wood Poles & Accesssory Equipment	a) Rotted pole (below ground and at ground level). b) Contamination of insulators. c) Pest infestation.	a) Pole and equipment on it could fall causing an outage, safety issues and environmental issues associated with oil leakage. b) Pole can catch fire due to tracking. c) Compromises pole strength; equipment can fall and drop; safety and environmental risks.
Overhead Switches	a) Burnt disconnect contacts due to contamination. b) Corroded or loose connections.	a) Overheating of parts that can lead to malfunction and/or equipment falling. b) Device misoperation or overheating of parts that can lead to malfunction and/or equipment falling.

[54] *Supra* note 49.

D2.2.2 Underground Grid System

The underground system consists of cables, transformers, switches, and civil infrastructure. All of these assets are placed at grade, below grade, or inside building vaults. The underground system eliminates many non-asset risks that are present in the overhead system such as foreign interference and weather-related interruptions. However, this system also presents unique non-asset risks, such as flooding or faster deterioration due to moisture build-up. Although this system generally provides better reliability than the overhead system, the causes of outages are more difficult to identify and restoration may take longer because the assets are underground and not visible to crews.

The Horseshoe underground distribution system is operated at 27.6 kV, 13.8 kV, with a subset of the system operating at 4.16 kV. The downtown underground distribution system is operated at 13.8 kV, and 4.16 kV. The main underground configurations are either radial or looped, with radial being the predominant configuration in the downtown system.

System types and configurations are sometimes mixed to provide better reliability or flexibility when repairs are required, as is the case with Underground Residential Distribution ("URD"). URD is a distribution configuration in parts of the downtown area with primary cables, switches and distribution transformers placed underground while secondary voltage connections remain overhead. The primary feeders consist of a main-loop, sub-loop and branch circuits. Customers are supplied directly from either the sub-loops or branch circuits, which allow sectionalisation (i.e. the ability to use switching to segment a feeder into sections) within the feeder to minimize interruptions when work is required, or to allow partial restoration of the feeder under fault conditions. Figure 18 shows a picture of a typical installation.

Figure 18: Typical Layout of Underground Residential Distribution

Toronto Hydro's underground system consists of approximately 4,000 underground switches, 30,800 underground transformers, 10,300 cable chambers, and 6,100 circuit-kilometres of underground primary and 6,800 circuit-kilometres of underground secondary cables.

Asset management activities related to the underground distribution system focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies, managing system performance with respect to reliability and power quality, and asset stewardship over the assets' lifespan.

Figure 19 provides the age demographic distribution of major underground assets. The age of XLPE cables represents a significant risk to reliability in the 2025-2029 rate period and must be prioritized.[55] Moreover, as of 2022, over 20 percent of underground transformers are approaching their useful life of 30 years, over 20 percent of cable chambers are approaching their useful life of 65 years and approximately 80 percent of cable chamber roofs are at or approaching their useful life of 25 years. Without proactive intervention, Toronto Hydro projects that the percentage of

[55] Exhibit 2B, Section 6.2.

underground assets having reached or exceeded useful life will increase from approximately 20 percent to 40 percent by 2029 for underground transformers, from 20 percent to 31 percent by 2029 for cable chambers, from 80 percent to 87 percent for cable chamber roofs.

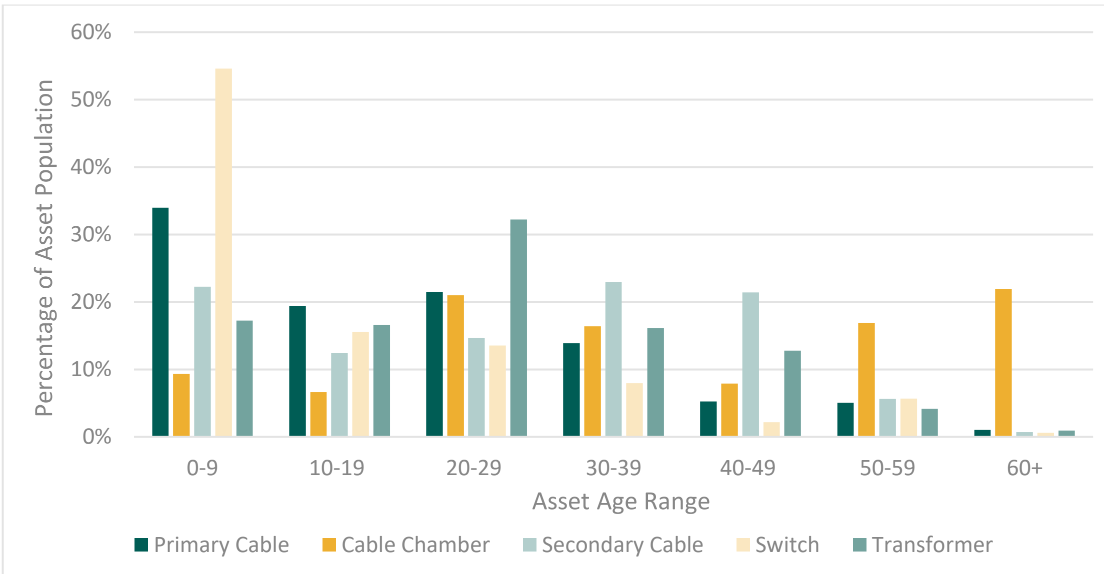


Figure 19: Underground Assets Age Demographic as of 2022

Underground switches, underground transformers and cable chambers are major underground asset classes for which Toronto Hydro performs an ACA. As shown in Figure 20, approximately 9 percent of Toronto Hydro's underground switches, 7 percent of underground transformers and 25 percent of cable chambers have at least moderate deterioration (i.e. HI3, HI4, and HI5) as of 2022. With over 2,000 cable chambers in HI3 condition, over 450 in HI4 condition, and 130 in HI5 condition (i.e. "end of serviceable life"), cable chamber replacement will continue to be a significant driver of both reactive and planned investment through 2029.

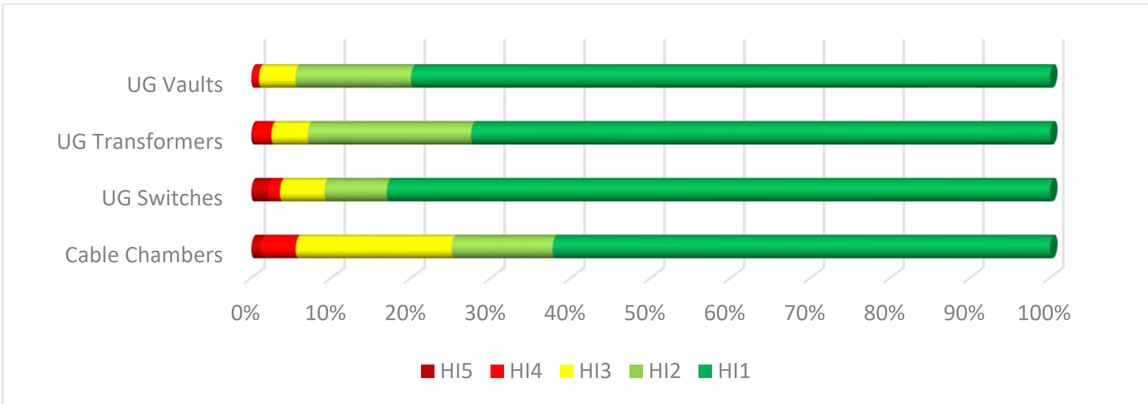


Figure 20: Asset Condition Assessment of Underground Assets as of 2022

Other key asset management performance measures that are relevant to the underground system include:

- **Oil Deficiencies:** Between 2020 to 2022, Toronto Hydro found, on average, 420 underground transformers with oil deficiencies per year. Assets replaced in the Underground System Renewal programs and Reactive Capital program will include assets exhibiting oil deficiencies found during inspections.
- **Priority Deficiencies:** The underground distribution system includes many below-grade vaults and cable chambers. The assets housed within them include cables, splices, joints, ducts, vents, hatchways, sump pumps, transformers, and switches. From 2019 to 2022, Toronto Hydro issued more than 25,000 work requests to address failing or failed underground assets. In 2022 alone, Toronto Hydro identified 496 P1, 1,677 P2, and 6,782 P3 priority deficiencies on the underground system.
- **PCBs:** Toronto Hydro has various types of underground transformers (e.g. submersible, padmounted, vault, and network), which can potentially contain PCB contaminated oil. 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, by 2025, predominantly through the Underground System Renewal programs (Section E6.2 and E6.3). If sub-standard conditions are found during inspections, replacements may be done through the Reactive and Corrective Capital program as well.

D2.2.2.1 Underground Legacy Equipment

1. Direct-Buried XLPE Cable

Cables are the single greatest contributor to defective equipment caused outages on Toronto Hydro's system, contributing on average 146,000 CHIs annually from 2013 to 2022. The underground system in the Horseshoe area consists of 666 circuit-kilometres that are direct-buried cable and direct-buried cable in duct, of which 286 circuit-kilometres are direct-buried XLPE cable. Approximately 73 percent of direct-buried cable has reached or is past its useful life as of 2022. Toronto Hydro has already begun to see deterioration in underground system reliability performance in recent years, and the utility expects that a failure to proactively address this aging asset group will have worsening impacts on outages caused by defective equipment failures.

These cables are susceptible to outages due to direct exposure to environmental conditions. "Water treeing" is the most significant degradation process for XLPE cable, and starts with moisture penetration into the cable insulation in the presence of an electric field. These "trees" are microscopic tears within the dielectric. Over time, continuous seepage of moisture into the insulation combined with electrical stress allows ions from the conductor to migrate into the microscopic tears. These tears then become carbonized and form electrical trees. Once this final stage of water treeing is reached, the cable quickly fails due to internal short circuits that occur between the primary conductor and the neutral shield on the outside of the cable insulation. Figure 21 depicts the internal short circuit that occurs once electrical trees are formed in the dielectric insulation. Figure 22 illustrates field and laboratory samples of microscopic voids bubbles) and damage to the insulation.

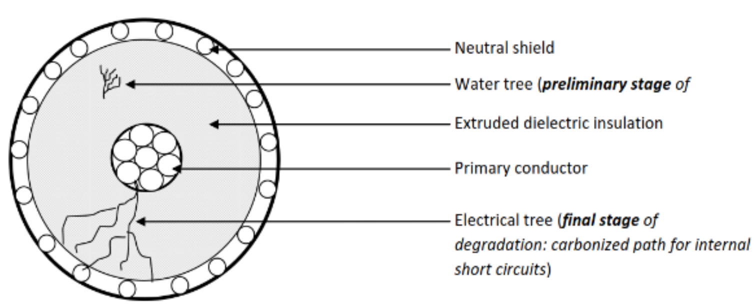


Figure 21: Cable Failure due to Electrical Treeing

Figure 22: Field and Laboratory Sample of Microscopic Voids and Damage XLPE Insulation

There is an immediate need to address the issues associated with direct-buried XLPE type cables so as to maintain system reliability for current and future customers in the Horseshoe area of Toronto. For further information, please see the Underground System Renewal – Horseshoe Program.[56]

2. Underground Lead Cable (PILC and AILC)

The majority of the cable in Toronto Hydro's downtown underground system is of two types: Paper-Insulated Lead-Covered ("PILC") and Asbestos-Insulated Lead-Covered ("AILC"). These cables are typically found at busy intersections beneath the sidewalks and roads of Toronto's downtown core. PILC cables are used as 13.8 kV primary cables, while AILC cables are used as secondary cables rated at 600 V. AILC cable is typically found on the secondary network 120/208 V and 240/416 V systems. Approximately 51 percent or 985 circuit-kilometres of Toronto Hydro's downtown primary system consists of PILC cable, whereas 49 percent or 176 circuit-kilometres of all secondary cable in the downtown network system consists of AILC cable.

Historically, utilities installed lead cable to take advantage of its reliability and compact design. However, over time, many utilities encountered environmental and health and safety issues with these cables. The industry has moved away from using these cables and for a number of years, there has been only one supplier remaining in the market for PILC (with none for AILC). Due to the supply risk (and the aforementioned environmental and safety risks), Toronto Hydro has avoided installing new lead cable for a number of years. Other utilities have taken a similar approach. As time passes,

[56] *Ibid.*

the number of individuals in the industry with the expert skillset required to work on lead cable in the field continues to diminish. Approximately 58 percent of all PILC cables and 93 percent of all AILC cables in the system are more than 30 years old. Toronto Hydro is continuing its proactive replacement of lead cables and plans to remove approximately 5.3 percent of 176 km AILC cable and 3.5 percent of 985 km PILC cable between 2025 to 2029. This is discussed further in the Cable Renewal segment of the Underground System Renewal – Downtown program.[57]

D2.2.2.2 Underground Assets Failure Characteristics

Table 3 provides a brief overview of the failure modes and impacts of underground asset failures.

Table 3: Underground Asset Failure Modes

Asset	Failure Mode	Effects
Underground Cable	a) Insulation degradation (eg. water trees). b) Carbon tracking in PILC cable paper insulation due to absence of oil medium (oil leak). c) Degradation due to age (cracked or degraded jacket).	a) Insulation breakdown and electrical fault. b) Impregnating oil dries up, cable overheats, degrading the insulation. c) Water ingress, corrosion of the metallic shield, penetration into the insulation (potentially causing water trees).
Submersible Transformers	a) Oil Leak. b) Corrosion of tank. c) Gasket deterioration due to age. d) Corroded secondary terminations (compression or bolted lugs).	a) Transformer cooling and insulating properties are diminished, electrical fault may occur. b) Oil leaks, transformer cooling and insulating properties are diminished; may result in internal components damage and electrical fault. c) Oil leaks, ingress of moisture may occur, transformer cooling and insulating properties are diminished. d) This failure mode can arise due to a flooding or contamination. Results in the secondary termination failure.

[57] Exhibit 2B, Section E6.3.

Asset	Failure Mode	Effects
Padmounted Transformers	a) Corroded enclosure. b) Enclosure has been exposed to moisture (ground water, moisture ingress). c) Contaminated or damaged insulating barriers. d) Degradation due to age/contamination. e) Gasket deterioration with age.	a) Public or animal access to the transformer. Transformer could be damaged or cause injury to the public. b) Improper ventilation, inadequate air flow, tracking, and flashover. Safety risks heighten as the transformer is located next to sidewalks. c) Tracking on the insulators, and eventual flashover. d) Insulation breakdown and electrical fault. e) Small traces of oil leaking. Ingress of moisture may occur; transformer cooling and insulating properties are diminished.
Underground Switches (Padmounted)	a) Loss of insulating properties due to contamination, moisture ingress, or humidity. b) Switch has been exposed to moisture (ground water, moisture ingress.	a) Flashover - presents a safety concern as the switch is located next to sidewalks. b) Improper ventilation and inadequate air flow create tracking and possible flashover and failure, presenting a safety concern as the switch is located next to sidewalks.
Cable Chambers	a) Collapsed duct. b) Excessive water leakage through ducts. c) Structural degradation at the neck. d) Cable racks and arms rust and deterioration. e) Cracks, spalling, delamination of concrete in walls or roof; corrosion in rebars.	a) Hotspot depending on the extent of damage, cable damage. Worst case can involve damage to connected equipment, posing a safety risk to the public. b) Degradation of walls, floor, corrosion to the racks. c) Access is restricted. If chamber is on roadway, a sinkhole may occur, posing a safety risk. d) Racks fall off the wall causing the cable or joint to be unsupported and possibly cause damage to other cables, posing a potential safety risk. e) Chunks of concrete falling down, structural collapse, wall or roof failure, and/or fire, posing a safety risk.

D2.2.3 Secondary Network System

The secondary network (or "network") system, which is predominantly found in the downtown Toronto area, was initially installed in the early-to-mid 1900s to improve reliability for critical loads. As the system evolved, it became recognized for its ability to efficiently serve medium sized loads in areas that have high density and small and narrow sidewalks. Such areas do not have sufficient space above grade for distribution infrastructure. The network system consists of interconnected low-voltage secondary cables, which are installed in a grid (also known as mesh) configuration. These grids are supplied by multiple network units housed in network vaults fed by different feeders, and offer additional redundancies that the typical overhead and underground distribution systems do not. Should a single primary feeder experience an outage, network connected customers will continue to be supplied from alternate primary circuits that continue to feed into the secondary grid. In this way, the secondary network system offers greater reliability than other underground or overhead systems.

At the heart of the network system are network units. The main difference between a network unit and a conventional radially-configured transformer is the addition of a network protector. The network protector prevents power from the secondary network grid from back feeding to the primary side. Should a fault occur on the primary side of the network unit, the network protector will automatically trip (i.e. open the switch to interrupt the current backfeeding into the fault). This protects the primary feeders from the fault, and allows the remaining network units to keep the secondary network grid up and running.

Though the network system is better at handling normal failure scenarios, in the case of a catastrophic failure such as a vault fire, the entire secondary network grid that is connected to the vault must be interrupted to allow emergency responders to extinguish the fire safely. In such a scenario, all connected customers are interrupted. To avoid these scenarios, network equipment must be kept in good condition to prevent vault fires or other failures from occurring. This is one of the reasons why Toronto Hydro takes a proactive approach to the maintenance and replacement of network units at risk of failure. Figure 23 below shows a typical submersible network unit.

Figure 23: Submersible Network Unit

The vaults that house network equipment are also an important component of the network system and must be maintained. If the integrity of a vault is compromised, the equipment inside the vault can be damaged, or the vault may become unsafe for employees. Unsafe conditions mean that crews are unable to complete any maintenance or repairs. Moreover, cracking and structural shifting of vault roof structures pose trip and fall hazards, and complete failure of roof elements can expose the public to energized electrical equipment. As of 2022, approximately 5.5 percent of network vaults and approximately 75 percent of network vault roofs past their useful life.

Figure 24 provides the age demographic distribution of major network assets. As of 2022, approximately 21 percent of network units and approximately 6 percent of network vaults are at or approaching their useful life of 35 years and 60 years, respectively. Without intervention, Toronto Hydro projects that the percentage of network units having reached or exceeded useful life will increase from 21 percent to 27 percent, and the percentage of network vaults will balloon from 6 percent to 26 percent by 2029. Non-submersible network units are one asset type that Toronto Hydro plans to target specifically. These units are susceptible to water ingress and elevated failure risks even when in good condition. As such, they need to be replaced to reduce the failure risks on the network system. Replacements will occur on a prioritized basis considering factors such as condition, as discussed in Network System Renewal program.[58]

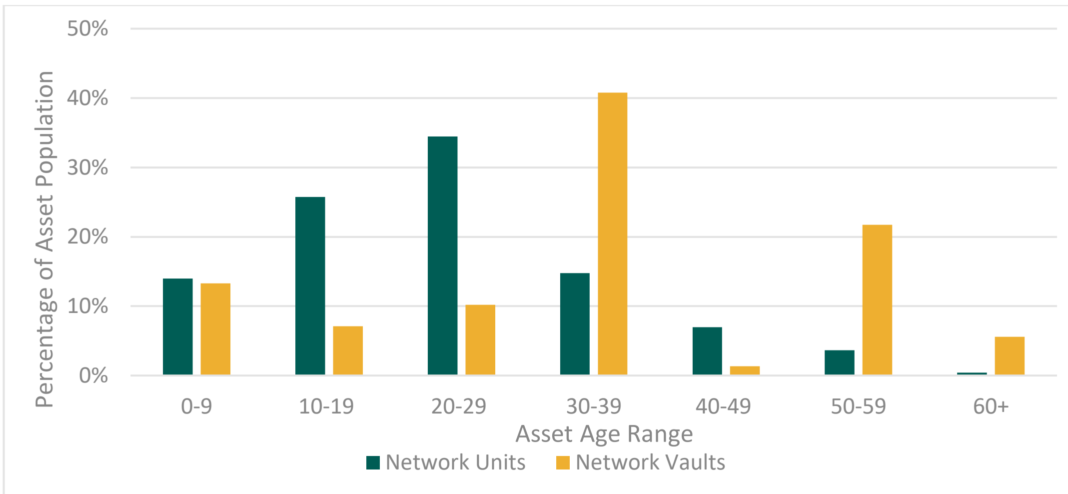


Figure 24: Network Assets Age Demographics as of 2022

Toronto Hydro performs an ACA for network transformers, network protectors, and network vault civil infrastructure. ACA results show that approximately 6 percent of network transformers, 29 percent of Toronto Hydro's network vaults and 15 percent of network protectors have at least moderate deterioration as of 2022.

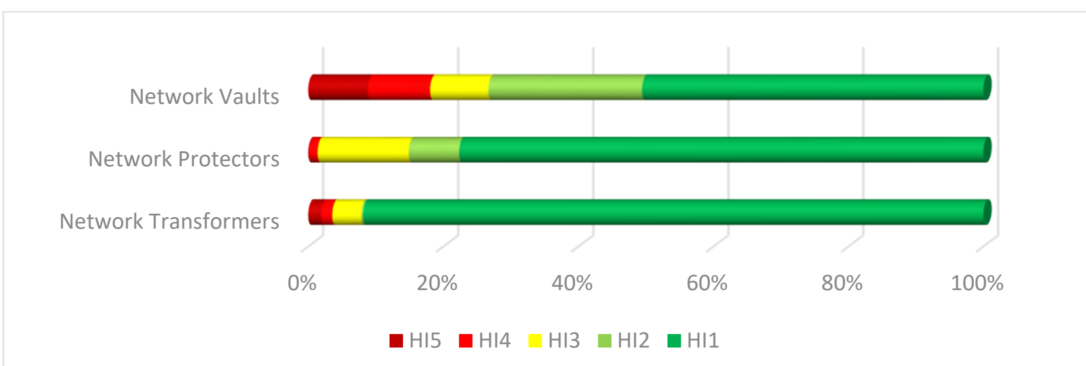


Figure 25: Asset Condition Assessment of Secondary Network Assets

Asset management activities related to the network focus on asset stewardship over asset life spans, mitigating environmental and safety risks, responding to system events and equipment deficiencies,

[58] Exhibit 2B, Section E6.4.

and managing system performance with respect to reliability and power quality. The following summarizes what this means relative to the measures set out in Table 2:

- **Oil Deficiencies**: Network transformers are the only asset group in the network system affected by this outcome. During the 2020-2022 period, Toronto Hydro found on average 47 oil deficiencies per year for network transformers. Assets replaced in the Network System Renewal Program and Reactive Capital Program will include assets exhibiting oil deficiencies found during inspections.
- **Priority Deficiencies**: Please see the discussion related to priority deficiencies under section D2.2.2 above as deficiencies related to the secondary network are generally tracked with all other underground deficiencies.

D2.2.3.1 Network Legacy Equipment

During the 2020-2024 rate period, Toronto Hydro has removed network legacy equipment, such as Automatic Transfer Switches ("ATS") and Reverse Power Breakers ("RPB"). Toronto Hydro continues to replace non-submersible network protectors as part of Network System Renewal program,[59] through 2029.

1. Eliminating Network Units with Non-Submersible Protectors

Although network units are replaced based on condition, another consideration that informs investment decisions is the presence of "non-submersible" designs which are characterized by ventilated or semi-dust-tight protectors. These units are susceptible to water ingress and elevated failure risks even when in good condition. The failure modes for network units are flooding and internal transformer failure. Flooding can damage the protector mechanism, causing the unit to short, or fail to operate, whereas transformer failure can result from overloading, low oil, moisture ingress, or age-related insulation deterioration. Toronto Hydro is continuing to replace non-submersible protectors with submersible protectors that feature watertight cases to help address flooding risks as part of the Network System Renewal program.[60] Figure 26 below shows the difference between a ventilated network unit and a submersible network unit, where the black protector identified is of a submersible design.

[59] *Ibid*.
[60] *Ibid*.

Figure 26: A ventilated Network Unit (Left) and a Submersible Network Unit (Right)

D2.2.3.2 Network Assets Failure Characteristics

Low voltage secondary distribution networks are susceptible to similar failure modes as other underground distribution systems; however, the consequences of failure to operate and network customer service reliability are often different, as outlined in Table 4 below.

Table 4: Network Asset Failure Modes

Asset	Failure Mode	Effects
Underground Primary Cable	a) Insulation degradation. b) Jacket damage. c) Mechanical stresses compromising geometry of cable. d) Multiple primary cable outages occur simultaneously.	a) Internal arc occurs; station circuit breaker trips causing feeder outage. b) Internal arc occurs; Network vaults continue to operate under contingency, with possible equipment overloads. c) Internal arc occurs; dual radial customers supplied by faulted feeder are interrupted until switched to alternate feeder. d) Equipment overloads may force the Control Room to drop the entire network, resulting in widespread customer interruptions.

Asset	Failure Mode	Effects
Underground Secondary Cable	a) Insulation degradation. b) Failed cable conductor contacts another conductor. c) Self-cleared secondary cable faults are not identified.	a) Arcing fault occurs. b) "Solid" fault occurs and may spread to adjacent cable junctions before self-clearing, resulting in interruptions to a small number of customers. c) Surrounding secondary cables may overload and eventually fault, resulting in interruptions to multiple customers.
Network Transformer	a) Insulation degradation due to age/contamination. b) Low or no oil level. c) Corrosion of the steel tank or gasket failure. d) Electric interlock stuck open and fails to prevent movement of the primary switch handle while transformer secondary is energized.	a) Internal insulation failure leading to an increased likelihood of catastrophics transformer failure due to the fact that the insulation characteristics are lost. b) Insulation fails to provide dielectric and mechanical insulation to the windings and may lead to major internal electrical fault in transformer or primary switch. c) Results in insulating oil leakage, which may cause contamination of the surrounding environment. d) Operator can move the handle without interference on an energized feeder; possibility of fatality.
Network Protector	a) Debris, salt, and moisture collect on the top of a network protector. b) Vault flooding allows water to enter the protector. c) Breaker mechanism gummed up, seized or broken. d) Motor fails (all possible causes), broken springs, broken close mechanism or motor fuse blown.	a) Causes an electrical short in protectors which typically result in vault fires, with the possible destruction of all electrical equipment in the vault. b) The mechanism fails and possibility of an electrical short; may result in permanent damage to the mechanism. c) Circuit breaker fails to close when instructed by relay. Motor fuse blows or motor may burn out, and excessive wears of moving parts. d) Motor assembly fails to provide mechanical force to charge springs that trip the circuit breaker open; moderate localized damage.

D2.2.4 Stations

Toronto Hydro's distribution system receives its transmission supply from Hydro One Networks Inc. ("Hydro One") at voltages of 230 kV, 115 kV at Transformer Stations ("TS"). In general, Toronto Hydro owns all of the medium voltage equipment up to the circuit breaker at a TS, subject to certain differences in ownership structures for each TS's equipment. Figure 27 below shows the ownership of station equipment and their associated demarcation point. In some areas, the voltage may be further stepped down to 13.8 kV or 4.16 kV at Municipal Stations ("MS") which are wholly-owned by Toronto Hydro.

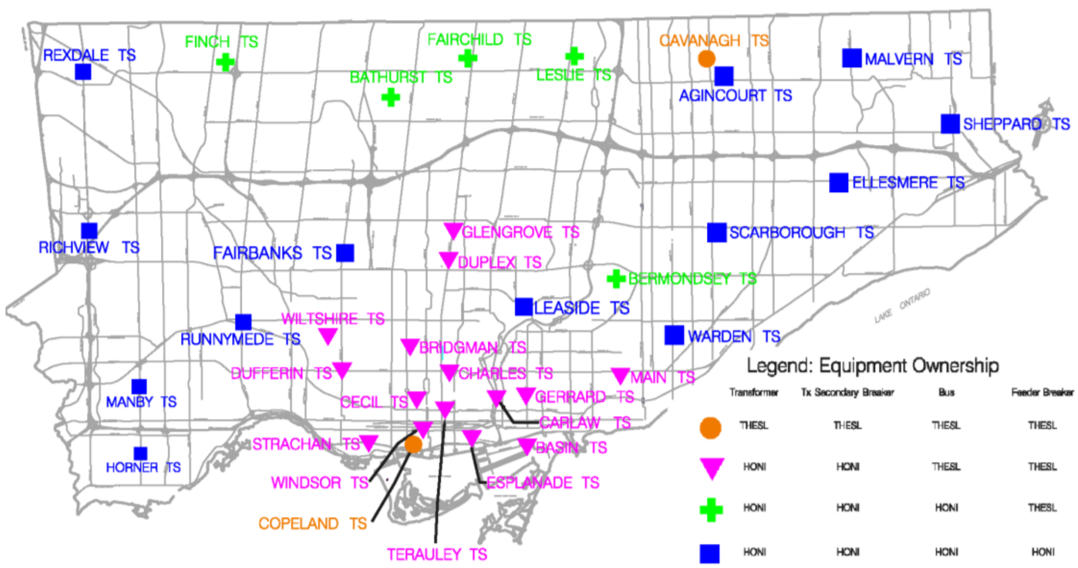


Figure 27: System Diagram of Station Components Ownership

Toronto Hydro is supplied by 37 TSs, including Copeland TS (as shown in Figure 27 above), and owns approximately 139 MSs. Within these stations, Toronto Hydro owns and operates approximately 200 switchgear, 175 power transformers, 40 outdoor circuit breakers, 80 remote terminal units ("RTUs"), and 170 direct-current ("DC") battery systems.

Feeders generally have at least one normally-open tie to another feeder to ensure there is a restoration option in case of an outage, or if planned work is required.[61] In the Horseshoe area, there are typically many normally open ties between feeders fed from the same bus or feeders fed from a

[61] Secondary network systems and pilot-wire/line-differential based systems operate with multiple supply points in parallel and do not require a normally open tie.

different bus or station. This allows for increased operational flexibility and the ability to restore some load in the event of a bus or station outage. Feeders in the downtown area rely on a radial configuration with normally open ties to feeders supplied from the same bus, but never have ties with feeders fed from other stations. This configuration limits the restoration options for these feeders in case of a station outage. Toronto Hydro does look for opportunities to build contingency ties between different downtown stations where economical. For example, Toronto Hydro invested $5.5 million to install interstation switchgear ties between Copeland TS and Windsor TS between 2020-2022. The Copeland to Windsor ties served three purposes: contingency support to prevent extended power outage in the downtown core, provide facilities to offload Windsor station switchgear to enable switchgear upgrade projects, and implement long-term downtown contingency ties between these two stations.

Asset management activities related to stations focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies when they are identified, managing system performance with respect to reliability and power quality, and asset stewardship over the assets’ life span.

Figure 28 provides the age demographic distribution of major station assets. Toronto Hydro’s critical stations asset base is of an increasingly advanced age on average. As of 2022, 42 percent of Toronto Hydro’s switchgear, 51 percent of power transformers, 42 percent of outdoor breakers, and 55 percent of DC battery systems are operating at or beyond their useful life. Without proactive intervention, the proportion of station assets operating beyond their useful life will continue to increase, contributing to already elevated asset failure risks for highly critical assets. Station asset renewal is complex and entails considerable operational constraints which limit the achievable level of renewal in a given year. Consistent investment and renewal work is needed to sustainably mitigate and control the failure risk presented by these assets.

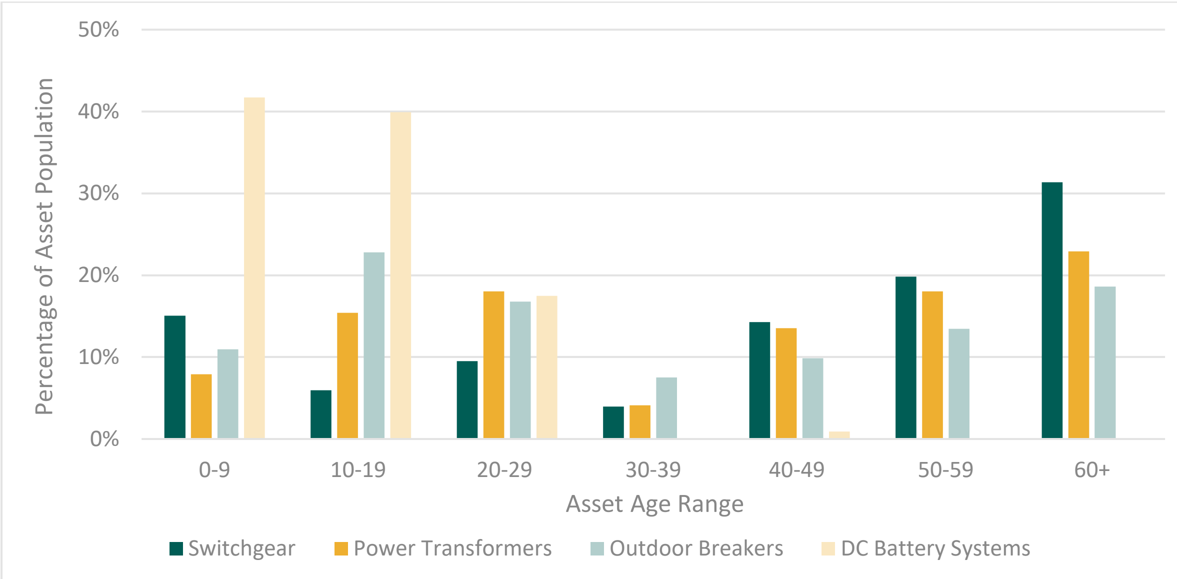


Figure 28: Stations Assets Demographics as of 2022

Within its stations asset classes, Toronto Hydro performs ACA analysis on its power transformers as well as various types of its circuit breakers. With the exception of standalone outdoor circuit breakers, circuit breakers are contained inside one of Toronto Hydro's switchgear and are considered components of their parent switchgear. Therefore, ACA performed on breakers helps serve as a proxy for switchgear condition.

Figure 29 shows that 98 percent of Toronto Hydro's air-blast circuit breakers, 93 percent of its oil circuit breakers, 39 percent of KSO oil circuit breakers, 12 percent of station power transformers, 78 percent of air-magnetic circuit breakers, 5 percent of SF_6 circuit breakers, and 1 percent of vacuum circuit breakers show signs of at least moderate deterioration. Accordingly, renewal of switchgear containing air-blast circuit breakers and oil circuit breakers are heavily targeted in the Stations Renewal Program.[62] Similarly, standalone outdoor KSO circuit breakers are prioritized for renewal in the proposed program.

[62] *Supra* note 46.

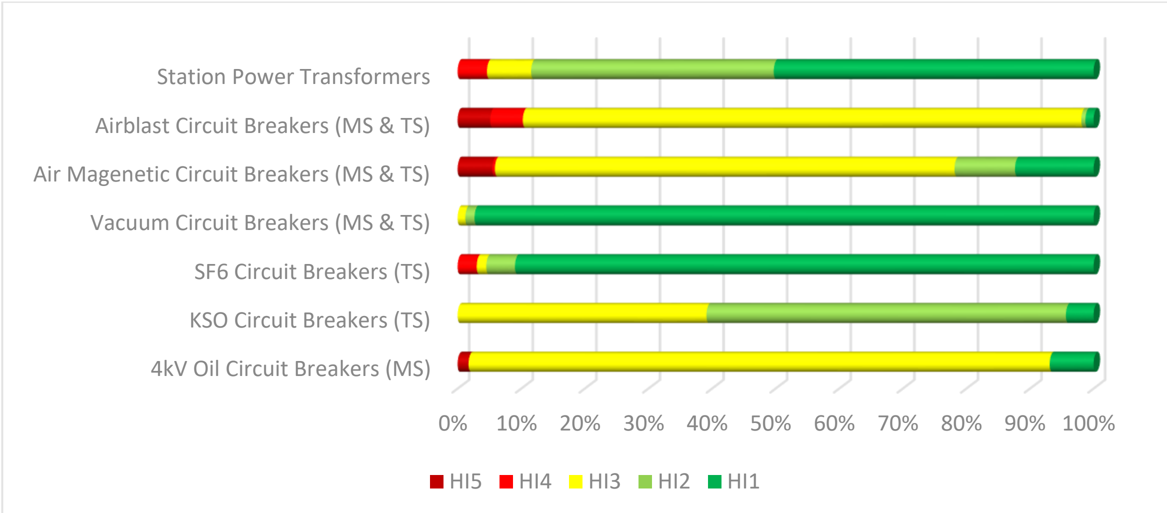


Figure 29: Asset Condition Assessment of Station Assets

Other key asset management performance measures that are relevant to the stations include:

- **Oil Deficiencies**: During the 2020-2022 period, Toronto Hydro found on average 12 station transformers with oil deficiencies per year. Assets replaced in the Station Renewal program,[63] and Reactive and Corrective Capital program will include assets exhibiting oil deficiencies found during inspections.[64]

- **Priority Deficiencies**: Station assets include power transformers, circuit breakers, switchgear, SCADA systems, relays, batteries and chargers, SCADA telemetry or control equipment, station alarms, DC panels, station heating, ventilation systems and sump pumps, which are installed across Toronto Hydro's 141 MSs and 37 TSs. From 2019 to 2022, Toronto Hydro issued more than 2,300 work requests to address failing or failed station assets.

D2.2.4.1 Stations Legacy Equipment

Toronto Hydro has many legacy station assets currently in operation, which are being phased out through capital renewal plans, as discussed in the Stations Renewal Program.[65]Legacy assets include: (i) non-arc-resistant brick and metalclad switchgear; (ii) air-blast, oil, KSO oil, and air magnetic circuit

[63] *Ibid*.
[64] *Supra* note 37.
[65] *Supra* note 46.

breakers; (iii) DACSCAN MDO-11, D20 ME, D20M++, and MOSCAD RTUs; electromechanical pilot-wire relays; and (iv) copper communications cable.

Oil and KSO oil circuit breakers are legacy assets which also present several risks including a safety risk to Toronto Hydro personnel, risk of collateral damage to adjacent station equipment, and in some cases a safety risk to the public or an environmental risk. Both oil and KSO oil circuit breakers contain oil, which may catch fire or even explode upon failure of the asset. KSO oil circuit breakers can also contain PCBs. By the end of 2029, Toronto Hydro plans to replace all remaining oil KSO circuit breakers with vacuum type breakers.

D2.2.4.2 Stations Major Assets Failure Characteristics

Table 5 below provides a brief overview of the failure modes and impacts of station asset failures. Typically, failure of these assets results in power outages to all customers supplied by the affected station bus, or even the entire station. In addition to power outages, station asset failures can lead to extensive and irreparable damage.

Table 5: Station Assets Failure Modes

Asset	Failure Mode	Effects
Switchgear	a) Control Cable lose connection due to breaker operation, auxillary socket broken or auxillary socket misalignment. b) Broken/cracked interphase barrier or insulators; dirt or debris on insulators. c) Total cable failure (all possible causes). d) Dirt or debris on busbar conductors.	a) Inability to monitor and operate the breaker via protection and control, and May result in an arc flash. b) Possible flashover, and safety issue involved with the failure due to the explosion if protection fails. c) Loss of power due to relay protection sensing the cable fault and tripping the breaker. d) May lead to overheating and melting of the busbar; flashovers might take out the whole bus and result in a major station shutdown.

Asset	Failure Mode	Effects
Power Transformer	a) Defective bushing gasket (Oil filled bushing). b) Paper insulation failure. c) Defective breather (all possible causes). d) Control circuit or motor failure of onload tap changer.	a) Oil leaks from the bushing may lead to loss of insulation, a short-circuit and eventually an outage. b) Power outage to entire station due to low or fluctuating voltage, or internal fault. c) Moisture enters through breather; moisture ingress will decrease insulation value of oil, eventually causing dielectric breakdown of oil. Flashover may occur. d) Failure to adjust output voltages to desired secondary voltages.
KSO Circuit Breaker	a) Worn latching mechanism or broken lifting rod. b) Breaker fails to open on a fault, no internal arcing occurs. c) Bushing failure causes flashover. d) Oil fails to insulate the live parts within the tank and also extinguishing the arc.	a) Operating mechanism fails to facilitate sequential movement of components to close the breaker; customers will be without power until transferred to alternate supply. b) Power outage to entire station switchgear. c) Power outage to entire station switchgear; flashover damages breaker. d) Breaker opens, but arc remains causing equipment damage and loss of bus. Breaker may rupture causing injury to workers in the vicinity, releasing fumes and oil into the environment and may cause damage to adjacent equipment.
DC Battery System	a) DC charger system fails. b) DC battery fails.	a) All station protection and control capability is lost after 8 hours when the battery has depleted. Station is then rendered inoperable. b) Station is noncompliant with Section 10.7.1 of the Transmission System Code. Should either the DC charger system or station service supply be out of service, then the station is rendered inoperable.

D2.2.5 Metering

Toronto Hydro utilizes several different meter types in order to ensure the reliable measurement of electricity acquired by the utility through the provincial transmission system and distributed to its customers. These include: (i) Residential, Small Commercial and Industrial; (ii) Interval; (iii) Suite Metering; and (iv) Wholesale.

- **Residential/Small Commercial & Industrial**: Toronto Hydro must continually upgrade its residential metering system to ensure that it continues to receive vendor support and is capable of enabling features on newer generation meters. The bulk of residential and small commercial and industrial meters have seals expiring between 2024 and 2026. As part of its AMI 2.0 initiative, Toronto Hydro plans to replace residential and small commercial and industrial meters with next generation meters.[66]
- **Interval**: Toronto Hydro plans to upgrade the Interval Metering system, ITRON Enterprise Edition ("IEE") to continue to successfully meter Toronto Hydro's interval metered customers (those with a demand of 50 kW or above). The upgrade is scheduled for completion by 2025. In 2017, Toronto Hydro had 7,000 Interval metered customers on IEE. In 2020, this increased to 14,000 customers due to the decommissioning of the 2G network in Toronto, and the subsequent conversion by Toronto Hydro of its 2G meters to newer 4G technology. By the end of 2022, Toronto Hydro's interval metered customers reached 17,000 customers due to conversion of various customer groups from manual reads and manual billing.
- **Suite Metering**: These meters represent the individually metered multi-residential buildings. The utility is legally obligated to provide suite meter installation services. Toronto Hydro offers this service in a competitive environment, and is also the provider of last resort in the event that the condominium chooses not to secure a third-party meter service provider. Currently, there are approximately 94,000 suites that are individually metered by Toronto Hydro and about 3,000 multi-residential buildings that are metered by one bulk meter. Toronto Hydro plans to continue to offer its suite metering services to new customers along with retrofit upgrades over the 2025-2029 rate period.
- **Wholesale**: Toronto Hydro plans to upgrade its wholesale revenue meters at all applicable wholesale metering points to comply with the metering standards mandated by the

[66] Exhibit 2B, Section E5.4.

Independent Electric System Operator ("IESO") Market Rules and Measurement Canada during the 2025-2029 period. These meters are installed at each of Toronto Hydro's transfer stations, and are used by Toronto Hydro to purchase power and to validate consumption with the IESO.

Toronto Hydro must maintain its fleet of meters in order to comply with both Measurement Canada and OEB mandates such as billing accuracy, estimated bills, and meter seals. In this regard, Toronto Hydro re-seals batches of meters to ensure accuracy and reactively replaces failed or non-communicating meters to ensure compliance. Toronto Hydro's meter population is aging with the majority of the residential and small C&I meter population reaching and exceeding 15 years of age during the 2025-2029 rate period. By 2025, approximately 90 percent of Toronto Hydro's residential and small commercial meters will surpass their useful life. To address this risk of failure, Toronto Hydro intends to replace its full population of first-generation residential and small C&I meters with next generation meters and supporting network infrastructure.

D2.2.5.1 Metering Major Assets Failure Characteristics

Table 6 below provides a brief overview of the failure modes and impacts of metering asset failures.

Table 6: Metering assets failure mode

Asset	Failure Mode	Effects
Energy Meter	a) Communications Failure	a) Bills must be estimated or meter manualy read
Instrument Transformer	b) Device Failure	b) Meter reads would be incorrect due to failed instrument transformers

D2.3 System Utilization

Toronto Hydro completes an annual System Peak Demand Forecast for station bus capacity to plan for short- and long-term load growth, additional capacity requirements to serve customers, and contingency scenarios such as planned work or loss of supply. This peak demand forecasting process is further explained in Section D4.1.1 and Section D3.3.1.1. To prevent system overloading which may lead to asset failures, the peak utilization of a bus should not reach or exceed 100 percent of its rated capacity for extended periods of time.[67] Bus capacity rating is determined based on the ratings for all of its associated equipment and a Limited Time Rating for upstream equipment provided by Hydro One. [68] Forecasting is performed at the bus level.

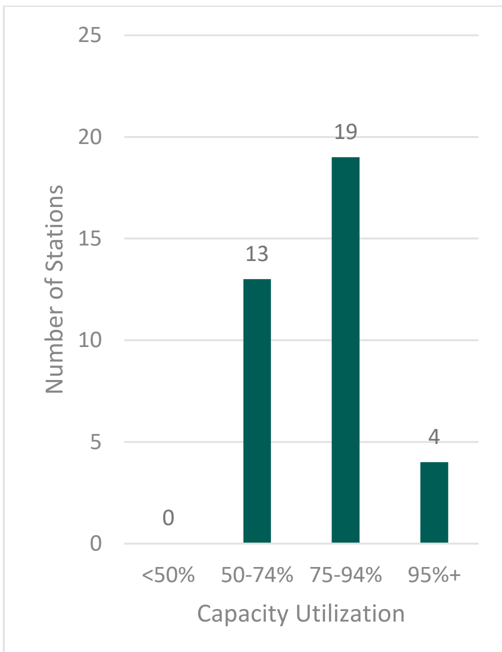


Figure 30: Forecasted Station Loading in 2025

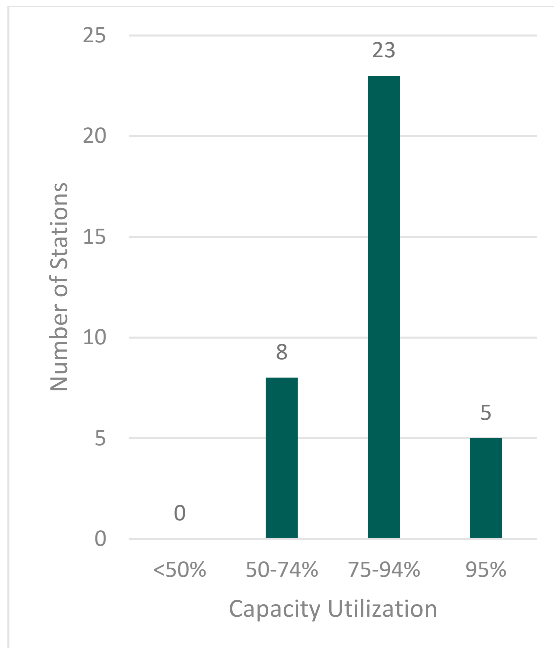


Figure 31: Forecasted Station Loading in 2030

From a station capacity standpoint, by 2025, 64 percent of Toronto Hydro stations will experience loading of 75 percent or higher, with four stations that are forecasted to be near capacity. By 2030, Toronto Hydro anticipates that the aforementioned percentage will increase to 78 percent, with five stations expected to exceed their capacity. Operating stations at 100 percent capacity would severely

[67] For planning purposes, a 95 percent loading threshold is used for the downtown region, while a 100 percent bus loading threshold is used for the Horseshoe. This difference in the threshold is due to the fact that there is more load transfer capabilities in the Horseshoe area than the downtown area so more time is required to make plans for downtown capacity constraints, than for Horseshoe capacity constraints. Further details of the load forecasting can be found in Section D3.1.2.1 Decision Support Systems as well as E7.7 Stations Expansion.

[68] Limited Time Rating ("LTR"): With respect to transformers, a limited time rating is a set of 15-minute, 2-hour, and 10-day MVA ratings determined by Hydro One in order to accommodate shorter time interval loading periods without causing equipment damage. All of Toronto Hydro's buses are supplied via at minimum two transformers operating in parallel. For bus capacity planning purposes, Toronto Hydro utilizes the 10-day LTR rating provided by Hydro One which is the maximum MVA the most limiting transformer can supply for a 10-day period with the other transformer out-of-service.

limit the utility's flexibility to manage abnormal system states (planned or unplanned). In a worst-case scenario, Toronto Hydro would be unable to maintain or replace a failing or failed asset.

More specifically, Toronto Hydro must also ensure that each of its stations has sufficient capacity to connect new or existing customers without sacrificing system reliability or operational flexibility for existing customers. Otherwise, extensive load transfers must be pursued through the Load Demand Program solely to free up the capacity needed to connect new customers without overloading a bus. Although this limit precedes station capacity, it is the primary driver for the need for extensive load transfers or station expansion projects so that new customer connections can be made.

To mitigate overloading at the stations and free up capacity to connect new large customers, Toronto Hydro analyzes each station's load forecast as well as available capacity in the area to resolve loading problems. Possible resolutions are to plan load transfers, upgrade existing components, or expand the station. A large number of limitations and considerations must be considered in implementing these solutions, including:

- incompatible system voltages (e.g. 27.6 kV vs. 13.8 kV);
- incompatible system types (e.g. radial versus looped, or overhead versus network);
- availability of civil infrastructure;
- availability of feeder positions;
- environmental or civil barriers (e.g. rivers, highways ravines); and
- relative cost between relief options.

Due to these various considerations, every station must be individually analyzed to determine an appropriate resolution.

On the feeder level, Toronto Hydro typically plans new customer connections or customer load increases by analyzing the area where the additional load requirements are emerging. Similar limitations and considerations at both the feeder level and station level must be accounted for in the planning process. This process is largely reactive given the significant uncertainty in forecasting feeder loading, because it is difficult to predict exactly where new loads will materialize and there are multiple feeders which can potentially connect new loads.

On the asset level, Toronto Hydro frequently reviews the system in areas of high capacity utilization or areas of poor reliability to determine what work can be undertaken to improve the system. It is difficult to monitor every asset in the system to ensure it is optimally utilized. Nonetheless, Toronto

Hydro has initiatives in place which will install new infrastructure and allow more assets to be closely monitored. Examples of such initiatives are network monitoring, stations control and monitoring replacements and new installations, and power transformer and switchgear replacements. These initiatives help prevent overloading which may cause premature equipment failure.

CLIMATE CHANGE VULNERABILITY ASSESSMENT UPDATE

November 18, 2022

Prepared for:
Toronto Hydro-Electric System Limited

Prepared by:
Stantec

Project Number:
160925171

The conclusions in the Report titled Climate Change Vulnerability Assessment Update are Stantec's professional opinion, as of the time of the Report, and concerning the scope described in the Report. The opinions in the document are based on conditions and information existing at the time the scope of work was conducted and do not take into account any subsequent changes. The Report relates solely to the specific project for which Stantec was retained and the stated purpose for which the Report was prepared. The Report is not to be used or relied on for any variation or extension of the project, or for any other project or purpose, and any unauthorized use or reliance is at the recipient's own risk.

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Prepared by: Bigelow, Dave — Digitally signed by Bigelow, Dave Date: 2022.11.18 10:08:57 -07'00'

Signature

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Printed Name

Reviewed by: Digitally signed by Wayne L. E. Penno, MBA, P.Eng Date: 2022.11.18 12:56:41 -05'00'

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Executive Summary

This Climate Change Vulnerability Assessment Update was conducted by Stantec to provide Toronto Hydro-Electric System Limited (Toronto Hydro) with updated climate parameters as described in the '2015 Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment', (AECOM and RSI, 2015: "the 2015 Study"). The main objective was to identify if any further work is required to update the adaptation actions recommended in the 2015 Study. The study uses updated climate projection data from the 6th Coupled Model Intercomparison Project (CMIP6), released along with the IPCC's 6th Assessment Report (AR6) in 2021, to estimate climate parameter probabilities. The two main tasks completed were to (1) update climate parameter probabilities and scores using CMIP6 data and scientific literature published since the 2015 Study; and (2) assess the materiality of the probability updates, by re-calculating the risk scores over the study period (from 2022 to 2050) following the PIEVC Protocol version 10 (Engineers Canada, 2011). Wherever possible, the same methods used in the 2015 Study were also used in this assessment.

To estimate the climate parameter probabilities, the complete ensemble of climate model outputs from the downscaled CanDCS-U6 dataset were used, and review of scientific literature, including the *Climate-Resilient Buildings and Core Public Infrastructure 2020* (Cannon et al., 2020) report was completed. A summary of the probability updates that resulted in a change to the probability scores is provided in the table below.

Climate Parameter	**Threshold**	**Frequency** (2030s)	**Probability** (Study Period)	**Probability Score** (Study Period)	**Probability Score Change** (2022-2015)
Daily Maximum Temperatures	Days > 40°C	0.08 (0 - 0.1)	90%	6	Decrease (-1)
Ice Storm/ Freezing Rain	25 mm ≈ 12.5 mm radial	-2.2% in 1/20yr ice accretion	96%	6	Decrease (-1)

Each combination of infrastructure asset class and climate parameter is referred to as an 'interaction'. The only climate parameters whose probability scores changed were 'days with maximum temperatures >40°C', and 'ice storms with >25mm of ice accretion', both of which decreased by 1. The updated probabilities resulted in material changes to the risk scores for 23 separate interactions (10 from daily maximum temperatures >40°C and 13 from Ice Storms >25mm), as summarized in the table below.

Climate Parameter	**Threshold**	**Study Report Year**	**Number of Interactions by Risk Class**		
			High	**Medium**	**Low**
Daily Maximum Temperature	40°C	2015	10	23	1
		2022	0	33	1
Ice Storm / Freezing Rain	25 mm ≈ 12.5 mm radial	2015	18	5	9
		2022	5	18	9

While the results show a slight decrease to the risk scores for these 23 interactions, the uncertainty in the climate projection data is high, therefore it is not recommended to relax the adaptation measures associated with extreme heat or freezing rain events from the 2015 Study.

Despite no change to the assigned probability scores, the annual frequency of high daily average temperatures >30°C (increase), heat waves (increase), and high nighttime temperatures (decrease) are all expected to change by >10% in the 2030s. The change is not material based on the approach applied. However, these climate parameters and their interactions with infrastructure asset classes may merit further study to identify whether the adaptation measures recommended in the 2015 Study report are sufficient to address the expected changes.

Acronyms / Abbreviations

AEP	Annual Exceedance Probability
AR5	5th Assessment Report
AR6	6th Assessment Report
BCCAQv2	Bias Correction/Constructed Analogues with Quantile delta mapping reordering
CanDCS-U6	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
CMIP5	Coupled Model Intercomparison Project 5
CMIP6	Coupled Model Intercomparison Project 6
ECCC	Environment and Climate Change Canada
EF	Enhanced Fujita Scale
GCM	Global Climate Model
IDF	Intensity-Duration Frequency
IPCC	Intergovernmental Panel on Climate Change
NTP	Northern Tornadoes Project
PCIC	Pacific Climate Impacts Consortium
PIEVC	Public Infrastructure Engineering Vulnerability Committee
RCP	Representative Concentration Pathway
RSI	Risk Sciences International
SSP	Shared Socioeconomic Pathway

1 Introduction

This study was conducted by Stantec Consulting Ltd. (Stantec) to provide Toronto Hydro-Electric System Limited (Toronto Hydro) with updated climate parameters as described in the '2015 Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment', (AECOM and RSI, 2015: "the 2015 Study"). The findings in this report are based on newly available global climate model (GCM) data from the 6th Coupled Model Intercomparison Project (CMIP6).

1.1 Background

A 2015 Study was conducted by AECOM and Risk Sciences International (RSI) using the latest climate projection information from the 5th Coupled Model Intercomparison Project (CMIP5) available at the time. The CMIP5 data was used to conduct a climate risk assessment using Engineers Canada's Public Infrastructure Engineering Vulnerability Committee's (PIEVC) assessment protocol (Engineers Canada, 2011) and estimate the vulnerability of Toronto Hydro's electrical distribution system to climate change and extreme weather events. The risk assessment included workshops, interviews, and an analysis of past climatic events to characterize the consequence of climate on Toronto Hydro's assets. Risk was evaluated by combining the climate hazard likelihood with the consequence information. The results of the 2015 Study were used to determine where infrastructure vulnerabilities to climate change were present and identify adaptation options to increase resilience.

In 2021, the IPCC released the 6th Assessment Report (AR6), as well as outputs from CMIP6, which represents an update to the latest climate change projection data from CMIP5. As one of the recommendations from the 2015 Study was to continue monitoring and evaluating climate change projection science, Toronto Hydro contracted Stantec to evaluate if the CMIP6 data will have a material change to the risk assessment set out in the 2015 Study.

1.2 Objective

The main objective of this assessment is to identify if any further study is required to update the adaptation actions recommended in the 2015 Study. This study uses updated climate projection data to estimate climate parameter probabilities and identifies whether these updates lead to materially different risk scores for Toronto Hydro's infrastructure asset classes over the study period.

1.3 Scope

The following scope of work has been completed as part of this assessment.

1. **Climate Parameter Probability Update:** Stantec collected downscaled CMIP6 global climate model data and reviewed scientific literature to estimate updated probability scores for the climate parameters found in the 2015 Study. This work aligns with Step 2, 'Data Gathering and Sufficiency' in version 10 of the PIEVC Protocol (Engineers Canada, 2011), as outlined in Section 1.2 of the 2015 Study.

2. **Materiality Assessment**: For those climate parameters where the probability score changed, Stantec re-calculated the study period risk score, to evaluate whether the change is material to each interaction. This aligns with Step 3, ‘Risk Assessment’, of the PIEVC Protocol, as outlined in Section 1.2 of the 2015 Study. We define a material change as one where the updated risk score fir an interaction crossed the risk tolerance thresholds from the 2015 Study.

Figure 1 outlines the work conducted in this study, and the nomenclature used to estimate climate-related risk to Toronto Hydro’s assets. Beginning with a review of climate data and scientific literature, we estimated the relevant climate parameters and their probabilities over the study period, then translated them to probability scores. The updated probability scores were used to re-calculate and revise the risk scores for each of the infrastructure asset class and climate parameter interactions investigated in the 2015 Study. For consistency with the 2015 Study, the methods and thresholds used to estimate the probability and risk scores followed those outlined in version 10 of the PIEVC Protocol (Engineers Canada, 2011).

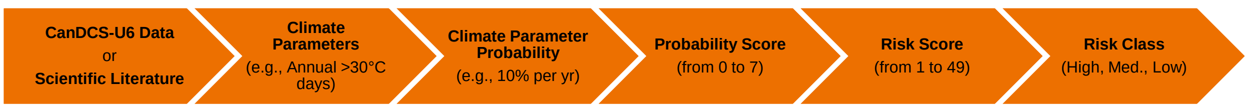

Figure 1: Project workflow

2 Climate Parameter Probability Update

This section describes the data and methods used to estimate updated climate parameter probabilities, and probability scores based on the updated climate data reviewed. The climate parameters investigated, and methods used to estimate probabilities align with the 2015 Study, except where noted otherwise.

2.1 Methodology

2.1.1 CLIMATE DATA

While the 2015 Study used coarse resolution (~200 km) climate projection information released along with the IPCC's 5th assessment report (AR5) – CMIP5, the Canadian Downscaled Climate Scenarios – Univariate (CMIP6), or CanDCS-U6, dataset produced by the Pacific Climate Impacts Consortium (PCIC) was used for this study. CanDCS-U6 is based on global climate model (GCM) outputs from the latest projections from the 6th Coupled Model Intercomparison Project (CMIP6), which were released in 2021. These represent a higher-resolution (~10 km grid) dataset that has been bias-corrected to align with a gridded historical weather reanalysis dataset (McKenney et al., 2011). The CanDCS-U6 dataset is delivered with daily resolution but is aggregated over 30-year time periods and across an ensemble of 26 models (Table 1) to estimate the range of climate parameter frequencies.

Table 1: Global Climate Models (GCMs) from CanDCS-U6 used in this study.

Model Name	Organization	Country	Organization Details
ACCESS-CM2	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
ACCESS-ESM1-5	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
BCC-CSM2-MR	BCC	China	Beijing Climate Center, China Meteorological Administration
CanESM5	CCCma	Canada	Canadian Centre for Climate Modelling and Analysis
CMCC-ESM2	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CNRM-CM6-1	CNRM-CERFACS	France	Centre National de Recherches Meteorologiques / Centre Europeen de Recherche et Formation Avancees en Calcul Scientifique
CNRM-ESM2-1	CNRM-CERFACS	France	Centre National de Recherches Meteorologiques / Centre Europeende Recherche et Formation Avancees en Calcul Scientifique
EC-Earth3	EC-Earth	Europe	EC-Earth Consortium
EC-Earth3-Veg	EC-Earth	Europe	EC-Earth Consortium
FGOALS-g3	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences

Model Name	Organization	Country	Organization Details
GFDL- ESM4	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
HadGEM3-GC31-LL	MOHC	UK	MetOffice Hadley Centre
INM-CM4-8	INM	Russia	Institute for Numerical Mathematics
INM-CM5-0	INM	Russia	Institute for Numerical Mathematics
IPSL-CM6A- LR	IPSL	France	Institut Pierre-Simon Laplace
KACE-1-0-G	NIMS-KMA	Korea	National Institute of Meteorological Sciences, Korea Meteorological Administration Republic of Korea
KIOST-ESM	KIOST	Korea	Korea Institute of Ocean Science & Technology Republic of Korea
MIROC-E2SL	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere
MIROC6	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MPI-ESM1-2-HR	MPI-M	Germany	Max Planck Institute for Meteorology
MPI-ESM1-2-LR	MPI-M	Germany	Max Planck Institute for Meteorology
MRI-ESM2-0	MRI	Japan	Meteorological Research Institute
NorESM2-LM	NCC	Norway	Norwegian Climate Centre
NorESM2-MM	NCC	Norway	Norwegian Climate Centre
TaiESM1	AS-RCEC	China	Research Center for Environmental Changes, Academia Sinica
UKESM1-0-LL	Met Office - NERC	UK	Met Office Hadley Centre, Natural Environmental Research Council

Climate parameter probabilities from the 2015 Study relied on the Representative Concentration Pathway (RCP) 8.5 emissions scenario from CMIP5, which is largely consistent with the Shared Socioeconomic Pathway (SSP) 5-8.5 (from CMIP6) (Riahi et al., 2017). The RCP scenarios represent different levels of greenhouse gas (and other radiative forcings) that might occur by 2100 (e.g., RCP 8.5 represents an additional 8.5 Wm^{-2}). CMIP6 data is based on SSPs, which interpret how different levels of climate change mitigation (or lack thereof) could be achieved to reach specific greenhouse gas concentrations. While there is debate surrounding which pathway from CMIP6 is the most likely, the SSP5-8.5 pathway represents a high-emissions (more pessimistic) scenario (Riahi et al., 2017). Climate projection data from SSP5-8.5 was used for this analysis as a conservative estimate of future climatic conditions, and to maintain consistency with the 2015 Study.

The Toronto Hydro study area encompasses 21 grid cells from the CanDCS-U6 dataset (Figure 2). Stantec calculated applicable climate parameters across the entire 26-member ensemble of climate models, before calculating the mean, 10th and 90th percentiles over all models to produce most-likely, lower- and upper-end estimates for each parameter (see Appendix A). While recent studies (Hausfather et al., 2022) have shown that averaging the complete CMIP6 ensemble of models may overestimate future temperatures due to model bias, all model members of the CanDCS-U6 ensemble are bias-corrected using the BCCAQv2 method (Cannon et al., 2015; Werner and Cannon, 2019), which corrects any potential biases to an observed historical dataset.

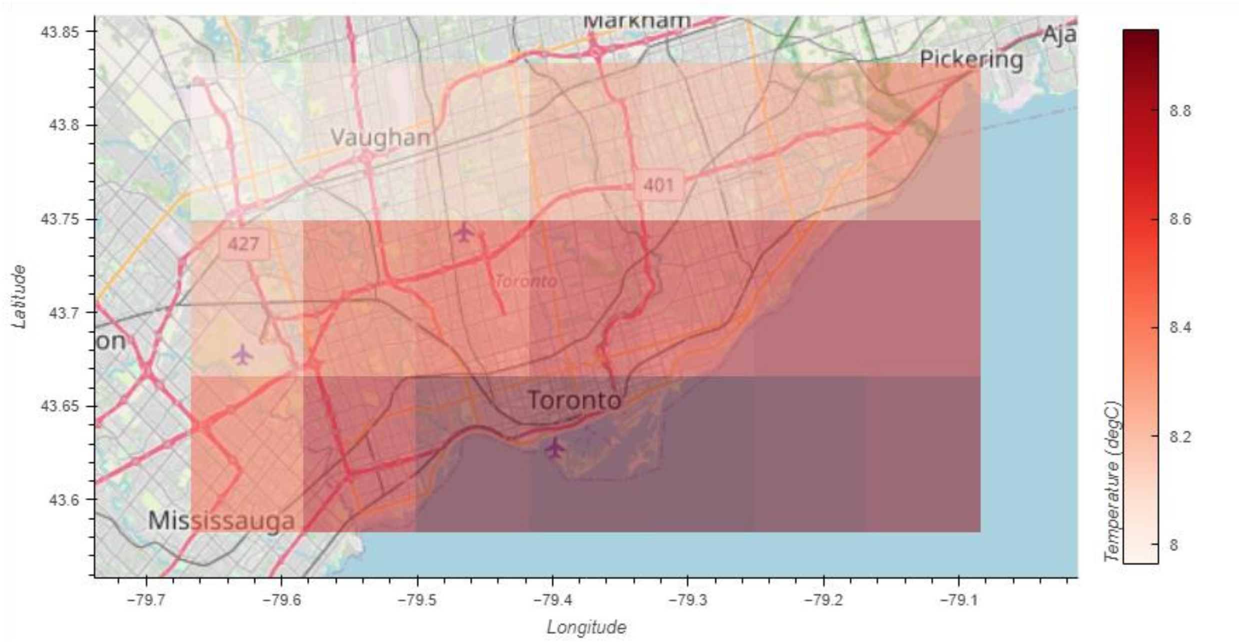

Figure 2: Mean air temperature over the baseline period (1981-2010), across the full CanDCS-U6 ensemble

Climate parameters that could not be calculated using the CanDCS-U6 data were investigated by conducting a literature review. The estimates of most of these parameters were derived using *Climate-resilient buildings and core public infrastructure (CRBCPI) 2020: An assessment of the impact of climate change on climatic design data in Canada* (Cannon et al., 2020). This document provides climatic design parameters based on the CanDCS-U5 dataset, which is a downscaled version of the CMIP5 data used in the 2015 Study. While the data are not based on the latest climate modelling (i.e., CMIP6), they do represent an update to the data used in the 2015 Study. Estimates of climate parameters that were not included in Cannon et al. (2020) relied upon other scientific publications identified by Stantec.

2.1.2 CLIMATE PARAMETER PROBABILITY

Some of the climate parameter probabilities were directly estimated from the CanDCS-U6 data (Table 2). Details on the methods used to calculate each parameter are provided in Section 2.2. To maintain consistency with the 2015 Study, the estimated frequencies/probabilities were adjusted to match the baseline values with those from the 2015 Study by applying the ‘delta’ approach as described in Appendix B, Section 3.3.1 of the 2015 Study report. The baseline probabilities from the 2015 Study are maintained in this study because their calculation relied on high-quality measurements obtained from weather stations, in contrast to the CanDCS-U6 baseline data, which rely on the less-precise NRCANmet dataset (Hopkinson et al., 2011).

Annual probabilities were estimated for the baseline period (1981-2010), the 2030s (2021-2050) and the 2050s (2041-2070), by dividing the number of event occurrences, by 30 years. The annual probabilities were then translated to study period probabilities by estimating the likelihood of occurrence over a 28-year period (from 2022 to 2050). Because seven years have passed since the 2015 Study (study period from 2015 to 2050), the length of the study period has changed, which influences the climate parameter probability of occurrence.

Table 2: Climate parameters and data sources used in the 2015 Study and the current (2022) study

Climate Parameter	Threshold(s)	2015 Data Source	2022 Data Source
Daily Maximum Temperatures	25°C, 30°C, 35°C, 40°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
High Daily Avg. Temperature	30°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
Heat Wave	3-days with max temp over 30°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
High Nighttime Temperatures	Nighttime low ≥23°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
Snowfall	5 cm, 10 cm daily	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
Frost-Free Days	0°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
Extreme Rainfall	100 mm in <1 day + antecedent	Kunkel et al. (2013)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6); Cannon et al. (2020)
Ice Storm/Freezing Rain	15 mm, 25 mm, 60 mm	Cheng et al. (2011, 2014)	McCray et al (2022); Jeong et al (2018); Jarret et al (2019); Cannon et al. (2020)
High Winds	70 km/h, 90 km/h, 120 km/h	Cheng et al. (2012); Cheng (2014)	Cannon et al. (2020)
Tornado	EF1+, EF2+	Brooks et al. (2014)	Cheng et al. (2013); Gensini et al. (2018); Sills et al. (2020)
Lightning	Flash density per km km^2	Romps et al (2014)	Cheng et al. (2013); Gensini et al. (2018); Sills et al. (2020)

The updated climate parameter probabilities were categorized into one of the eight probability score classes used in the 2015 Study (Table 3). While more recent versions of the PIEVC protocol exist (e.g., the PIEVC High-Level Screening Guide – ICLR, 2022), Stantec applied the same scoring thresholds used in the 2015 Study to maintain consistency and comparability.

Table 3: Probability score classes applied in this study and the 2015 Study (from Engineers Canada, 2011)

Probability Score	Annual Probability	
0	<0.1 %	<1 in 1,000
1	1 %	1 in 100
2	5 %	1 in 20
3	10 %	1 in 10
4	20 %	1 in 5
5	40 %	1 in 2.5
6	70 %	1 in 1.4
7	>99 %	>1 in 1.01

2.2 Results

Updates to the projected annual frequency (2030s), study period probabilities, and probability score for each climate parameter are summarized in Table 4. For parameters derived from the CanDCS-U6 data, the mean, 10th, and 90th percentiles of the frequency (across 26 models) are provided. A more detailed comparison, including baseline probabilities and 2050s projections is included in Appendix A for reference. Specific methods applied and results obtained for each climate parameter are described in detail later in this section.

Table 4: Updates to climate parameter probabilities

Climate Parameter	Threshold	Frequency[1] (2030s)	Probability (Study Period)	Prob. Score (Study Period)	Score Change (2022 - 2015)
Daily Maximum Temperatures	Days > 25°C	86 (64 - 102)	>99%	7	None
Daily Maximum Temperatures	Days > 30°C	28 (10 - 41)	>99%	7	None
Daily Maximum Temperatures	Days > 35°C	2.8 (0 - 7)	>99%	7	None
Daily Maximum Temperatures	Days > 40°C	0.08 (0 - 0.1)	90%	6	Decrease (-1)
High Daily Avg. Temperature	Days > 30°C	0.75 (0 - 2.2)	>99%	7	None
Heat Wave	3+ consecutive days >30°C	2.6 (0.9 - 5.9)	>99%	7	None
High Nighttime Temperatures	Nighttime low ≥23°C	2.6 (0.1 - 5.9)	>99%	7	None

[1] Refers to annual frequency (days per year), unless otherwise noted in column 2. The values in parentheses indicate the 10th and 90th percentiles across 26 downscaled GCMs, from the CanDCS-U6 data.

Climate Parameter	Threshold	Frequency[1] (2030s)	Probability (Study Period)	Prob. Score (Study Period)	Score Change (2022 - 2015)
Snowfall	Days w/ >10 cm	1.2 (0 - 2.6)	100%	7	None
Snowfall	Days w/ > 5cm	4.4 (1.6 - 7.6)	100%	7	None
Frost-Free Days	Days > 0°C	249 (242 - 279)	100%	7	None
Extreme Rainfall	100 mm in <1 day + antecedent	+11% rainfall intensity	75%	6	None
Ice Storm/ Freezing Rain	Accretion 15 mm	-2.2% in 1/20yr ice accretion	99%	7	None
Ice Storm/ Freezing Rain	25 mm ≈ 12.5 mm radial	-2.2% in 1/20yr ice accretion	96%	6	Decrease (-1)
Ice Storm/ Freezing Rain	60 mm ≈ 30 mm radial	-2.2% in 1/20yr ice accretion	23%	4	None
High Winds	>70 km/h+	+0.7% in 10-yr wind speeds	>99%	7	None
High Winds	>90 km/h	+0.7% in 10-yr wind speeds	>99%	7	None
High Winds	>120 km/h	+0.8% in 25-yr wind speeds	76%	7	None
Tornado	EF1+	-	~0.6%	1	None
Tornado	EF2+	-	~0.3%	0	None
Lightning	Flash density per year per km^2	1.43	55% (Lg)	6	None

2.2.1 HEAT-RELATED PARAMETERS

Each of the heat-related parameters (Daily Maximum Temperature, High Daily Average Temperature, Heat Wave, and High Nighttime Temperature) were calculated directly from the CanDCS-U6 data. These parameters were shifted using an additive correction factor to match the baseline values to those provided in the 2015 Study. The heat-related climate parameters are defined as follows:

- Daily Maximum Temperatures above threshold temperature (25°C, 30°C, 35°C, and 40°C) – number of days per year when the maximum daily temperature exceeds a threshold.
- High Daily Average Temperature (above 30°C) – number of days per year when the average daily temperature exceeds 30°C.
- Heat Waves – number of times per year when the maximum daily temperature exceeds 30°C for three or more consecutive days.
- High Nighttime Temperatures (above 23°C) – number of days per year when minimum daily (nighttime) temperature exceeds 23°C.

There is an increase in the estimated number of days with maximum temperatures exceeding 25°C, 30°C, and 35°C in the 2030s and 2050s compared to the 2015 Study (see Appendix A). For each of these parameters, the probability of occurrence over the study period is almost certain (>99%). Because the 2015 Study already assigned the maximum probability score of 7 (>99%) over the study period, these values remain unchanged.

There is a decrease in the estimated number of days with maximum temperatures exceeding 40°C in the 2030s and 2050s, compared to the 2015 Study. As a result, the estimated probability of 40°C temperatures occurring over the study period is about 90% and is classified as a probability score of 6, a decrease from the 2015 Study score of 7.

The projected number of days with daily average temperature greater than 30°C is higher than that provided in the 2015 Study, increasing from 1.2 days per year to 4.3 days per year. The CanDCS-U6 data were also used to estimate the frequency in the 2030s, which was not previously provided. However, since the 2015 Study already assigned the maximum probability score of 7 (>99%) over the study period, the updated climate data do not justify a change to the probability score assigned.

The expected number of heat waves per year aligns with the values provided in the 2015 Study, however the CanDCS-U6 data allow for a more precise estimate of the annual frequency in the 2030s and 2050s. The 2015 Study projected more than 1 heat wave per year in the 2030s and 2050s, whereas the updated climate data indicate that 2.6 and 4.8 heat waves are expected per year, respectively. However, since the 2015 Study already assigned the maximum probability score of 7 (>99%) over the study period, the updated climate data do not justify a change to the probability score assigned.

The expected number of days with high nighttime temperatures is lower than the estimates provided in the 2015 Study, decreasing from 7 and 16 to 3 and 11 in the 2030s and 2050s, respectively. While this represents an almost 50% decrease, the probability of occurrence over the study period is still almost certain (>99%), and therefore the updated climate data do not justify a change to the probability score of 7 assigned in the 2015 Study.

2.2.2 FROST-FREE DAYS

Frost-free days were estimated using the CanDCS-U6 data. This parameter represents the number of days per year when the daily minimum temperature exceeded 0°C. The frequencies estimated from the CanDCS-U6 data were shifted using an additive correction factor to match the baseline value to that provided in the 2015 Study.

While there is a slight increase in the estimated number of frost-free days in the 2050s compared to the 2015 Study (increase 5 days), the differences are small in comparison to the annual number of frost-free days projected (278 days). Further, the 2015 Study assigned a probability score of 7 (>99%) over the study period. This score means that frost days (i.e., temperatures below 0°C) are effectively certain throughout the study period. These findings are supported by the updated climate data, and the probability scores remain unchanged.

2.2.3 EXTREME RAINFALL

While extreme rainfall events at the daily and higher resolution can be captured by the CanDCS-U6 dataset, the latest recommendations from Environment and Climate Change Canada (ECCC) suggest alternate methods to estimate future extreme rainfall. The approach uses the relationship between warming temperatures and precipitation extremes to update empirically based rainfall intensity-duration-frequency (IDF) curves for future climate projections (Canadian Standards Association, 2019). This method is described as 'temperature scaling', which is defined as $\boldsymbol{R_P = R_C \times 1.07^{\Delta T}}$, where R_P is future estimated rainfall intensity value, R_C is the current rainfall intensity value, and ΔT is long-term (30-years or more mean) annual mean temperature change for the study location. IDF change factors ($1.07^{\Delta T}$) based on CMIP5 data for cities across Canada are provided in Cannon et al (2020), accounting for site-specific projections in temperature change.

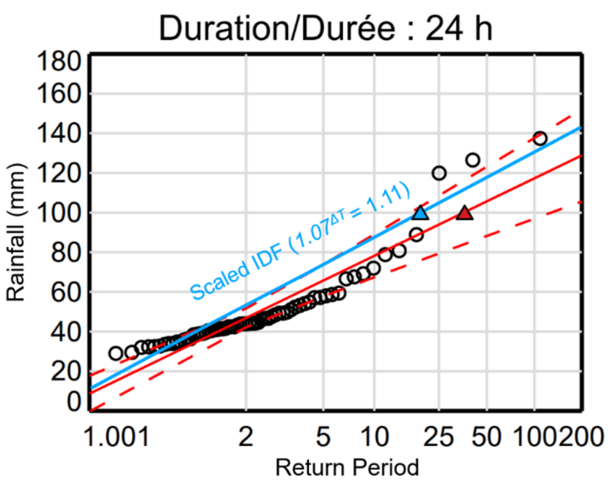

Figure 3: Scaled 24-hour rainfall probability curve for Toronto Pearson Airport, from ECCC. Triangles denote 100-mm rainfall probabilities for the baseline (red) and 2030s (blue).

For the Toronto area, the IDF change factor is given as 1.11, for the year 2035 (midpoint of the 2030s) for the RCP8.5 emissions scenario (Cannon et al., 2019 – Table 2.1). The 2015 study provides a baseline annual probability of 4% for 100 mm of rain in 24 hours, which generally agrees with the latest IDF curves for the Pearson Airport weather station, provided by ECCC (3%, or 33-year return period) (blue triangle, Figure 3). Applying the change factor to the latest IDF curve for Pearson Airport, gives an estimated annual probability of ~5% for a 100mm/24hr rainfall event in the 2030s (red triangle, Figure 3) and a study period probability of 75%. Using Table 3, this results in a probability score of 2 for the 2030s, and 6 for the study period, which is the same as that provided in the 2015 study.

While using downscaled climate model (e.g., CanDCS-U6) rainfall data is not the recommended approach for estimating future extreme rainfall probabilities from ECCC, the approach still merits investigation for this analysis. The mean probability of >100mm of rainfall in a 24-hour period across the CanDCS-U6 ensemble in the 2030s is ~0.02 (score of 2) resulting in a study period probability of 57% (score of 6), which agrees with the recommended approach discussed above.

2.2.4 SNOWFALL

The future probabilities of 5 and 10 cm snowfall events were estimated using the CanDCS-U6 data. Snowfall was approximated from temperature and precipitation data using the 'Brown' method presented in Verseghy (2009), which assumes the fraction of precipitation falling as snow decreases linearly between 0 °C (100% snow and 0% rain) and 2 °C (0% snow and 100% rain). The results were then converted from mm of water equivalent to snow depth (in cm) using a density of 150 kg/m^3, which was selected to align with the number of 5 and 10 cm snowfall events provided in the 2015 Study (i.e., the snow density was used as a multiplicative correction factor). Cannon et al. (2020) notes that while there is medium confidence that snow loads will decrease over most of Southern Canada, there is low confidence in the magnitude of the decrease.

The results indicate the annual frequency of 5 cm snowfall events will decrease from 5.2 events per year in the baseline period to 4.4 in the 2030s, and 3.1 in the 2050s. Larger (10 cm) snowfall events are estimated to decrease in frequency from 1.4 events per year in the baseline to 1.2 and 0.9 events per year in the 2030s and 2050s, respectively. Despite the projected decrease in annual frequency of snowfall events, the probability of both 5 and 10 cm snowfall events occurring over the study period is almost certain (>99%), and therefore the probability scores from the 2015 Study remain unchanged (score of 7).

2.2.5 FREEZING RAIN

The future probabilities of freezing rain events were estimated based on a review of recent climate change literature applicable to the Toronto area, including McCray at al. (2022), Jeong et al. (2018), and Cannon et al (2020). The freezing rain events considered included 15, 25, and 60 mm of ice accretion, as defined in the 2015 Study.

While the studies do not explicitly provide estimates of the likelihood of the freezing rain events listed in the 2015 Study, McCray et al. (2022) and Jeong et al. (2018) found that the frequency, and magnitude, respectively, of freezing rain events are projected to decrease slightly in the Toronto area. Cannon et al. (2020) found 'with medium confidence' that while the magnitude of freezing rain events is expected to increase across Canada in general, there is a very small, expected decrease in the Toronto area (very low confidence). Specifically, they estimate reductions of 2.2% and 7.7% in ice thickness for the 1/20-year (5% annual exceedance probability) events based on 1°C and 1.75°C of global mean warming. These global mean warming estimates are consistent with the years 2035 (2030s) and 2055 (2050s) for the RCP8.5 emissions scenario (Cannon et al., 2019 – Table 2.1).

As a conservative approach, Cannon et al (2020) recommend using ice accretion loads established from recent historical data (i.e., no projected change in ice storm magnitude). In consideration of each of these sources, and the significant uncertainty expressed in each, the estimates probability score for each type of freezing rain event (10, 20, 30 mm) is likely to remain steady over the study period, as compared to the baseline. The updated study period probability scores are not changed for 10- and 30-mm events (7 and 4, respectively), but are decreased (from 7 to 6) for 20 mm events, compared to the 2015 Study.

2.2.6 WIND

The future probabilities of extreme wind events were estimated based on a review of recent climate change literature for the Toronto area (Cannon et al,2020). The extreme wind events considered include 70, 90 and 120 km/h wind thresholds, as defined in the 2015 Study.

Cannon et al. (2020) project a slight increase of extreme wind speeds in the Toronto area, with very low confidence. They estimate increases of 0.7% and 0.8% in hourly wind speeds for the 1/10-year (10% annual exceedance probability; AEP) and 1/25-year (4% AEP) events based on +1.0°C of global mean warming, which is consistent with the year 2035 (2030s) for the RCP8.5 emissions scenario (Cannon et al., 2019 – Table 2.1). The estimated increases for +1.75°C (equivalent to 2055/2050s for RCP8.5) are 2.7% and 3.4% for 1/10-year and 1/25-year events, respectively. These return periods were selected from the available data provided by Cannon et al (2019) to best align with the baseline probabilities from the 2015 Study (>100% AEP for 70 and 90 km/hr events, and 5% AEP for 120 km/hr events).

Cannon et al. (2019) emphasize that these wind speed projections are provided with very low confidence, because of (1) the limited amount of scientific literature, (2) a low signal-to-noise ratio in the projected changes, and (3) the general inability of climate models to simulate extreme winds associated with small-scale processes that influence wind speeds. Because the projected increases in wind speeds are small, and the confidence is very low, we have assigned probability scores that are consistent with the baseline for each threshold event (7, 7, and 2 for 70 km/hr, 90 km/hr and 120 km/hr events, respectively), which are also consistent with the scores from the 2015 Study.

2.2.7 TORNADOES

A review of recent climate change literature applicable to the Toronto area was conducted to identify whether any updates were required to the tornado probability estimate from the 2015 Study. The specific tornado events considered included those with strengths of EF1+ (wind speeds exceeding 138 km/h) and EF2+ (wind speeds exceeding 178 km/h) on the Enhanced Fujita (EF) scale.

Sills et al. (2020) used multiple methods (e.g., satellite imagery, drone and ground surveys) to identify tornadoes and assess their size and intensity in the Ontario region between 2017 and 2019 as part of the Northern Tornadoes Project (NTP). Using a systematic approach, they captured 78% to 283% more tornadoes annually than the 30-year Canadian national tornado dataset from 1980-2009, mainly due to their increased usage of satellite imagery, ground and drone surveys and an improved storm track identification. It is important to note that although there is a detected increase in tornado occurrence through NTP, it does not signify any relevant changes in the tornado frequency in Canada.

Figure 4 shows all NTP-documented tornadoes (from 2017-2019) in Southeastern Ontario, with selected contours from the tornado frequency modeling of Cheng et al (2013). Gensini and Brooks (2018) note that tornado environments have been shifting northeastward in the central United States, however Sills et al. (2020) emphasize that it would take numerous years before any trends could be confirmed in Canada. In

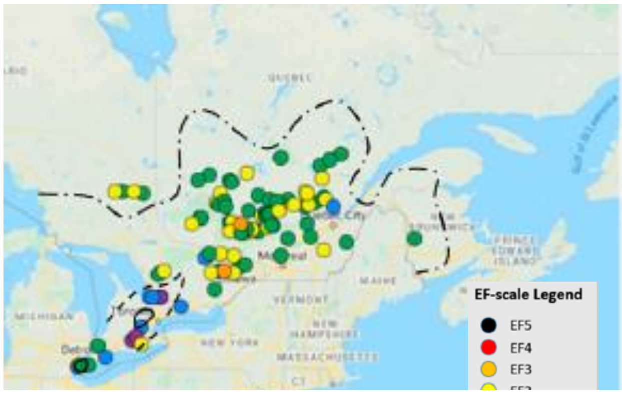

Figure 4: 2017-2019 tornadoes recorded by Sills et al. (2020), overlain with contours of annual tornado frequency in tornadoes per 10,000km2 per year from Cheng et al. (2013): dash-dotted = 0.1, dashed = 1.0, solid=2.0.

consideration of each of these sources, and the uncertainty expressed in each, the tornado probability scores from the 2015 Study remain unchanged (1 and 0 for EF-1 and EF-2 tornadoes, respectively).

2.2.8 LIGHTNING

The future probability of lightning was estimated based on a review of recent climate change literature and data applicable to the Toronto area (Romps et al (2014), Romps (2018) and Finney et al. (2018)). Lightning probability is quantified using the flash density per km^2.

The baseline probability of lightning events provided in the 2015 Study was estimated using data collected from the North American lightning detection network between 1999 and 2008. Environment Canada has since published mean annual lightning flash-density values for the Toronto Area over the period of 1999-2018. Because the time period of the updated data is twice as long as that from the data provided in the 2015 report, the new value provided by Environment Canada is used in this study. The updated value is 1.43 flashes per km^2 per year, which is consistent with the range provided in the 2015 Study (1.12-2.24 flashes per km^2 per year).

As noted in the 2015 Study, Romps et al. (2014) estimate that lightning strikes are projected to increase by 7-17% per degree Celsius of global warming. Similarly, Romps (2018) estimate increases of 8-16% per degree Celsius of warming, using two separate indices. Finney et al. (2018) however, applied a different approach to estimate changes in lightning frequency with climate change, and found that lightning frequency may decrease with warming global temperatures. Due to the general lack of literature linking lightning to climate change, the lack of consistency between projections, and the limited number of models applied in these studies, it is estimated the probability of lightning occurrence will not change significantly under a changing climate. As such, the probability score over the study period is 6, which represents no change from the 2015 Study.

3 Materiality Assessment

3.1 Materiality Methods

Each combination of climate parameter and infrastructure asset class is referred to as an interaction (e.g., the interaction between extreme heat and downtown core stations). To assess material changes in risk, Stantec calculated risk over the study period (2022-2050) for each interaction. Risk is calculated following the approach outlined in the 2015 Study, where ***Risk Score = Probability Score x Severity Score*** (Engineers Canada, 2011). Updated risk scores were only calculated for climate parameters for which the probability score differed from that assigned in the 2015 Study (freezing rain events (>25mm) and extreme heat events (>40°C)). Severity scores used to estimate risk in the 2015 Study were also used in this study.

Updated risk scores were calculated for 66 interactions (42 infrastructure asset classes and two climate parameters – note that some infrastructure asset classes are not exposed to extreme heat or ice storms). The results were then compared with the tolerance thresholds from the 2015 Study to classify the risks. Material changes (either positive or negative) were then identified based on whether the risk score crossed the threshold into a new class.

Table 5: Risk tolerance thresholds (classes) from the 2015 Study

Risk Score	Risk Class	Response
<12	Low Risk	Monitoring or no further action necessary
12 - 36	Medium Risk	Vulnerability may be present. Action may be required, to be determined through engineering analysis
>36	High Risk	Vulnerability present, action required

3.2 Materiality Results

Only two of the updated climate parameters probability scores were different from the 2015 Study: (1) daily maximum temperatures (>40°C) and (2) freezing rain/ice storms (>25 mm). Each of these probability scores, were reduced from a very high probability (7) to high probability (6). Based on these updated probability scores, the estimated risk for 23 of the interactions were calculated to be materially different from the 2015 Study. The materially different interactions, and their risk scores, are outlined below and in Table 6.

- Ten infrastructure asset classes at high risk to daily maximum temperatures >40°C changed to medium risk. All these material changes were for Transmission Step-down to Municipal and Municipal Stations.
- Thirteen infrastructure asset classes at high risk to freezing rain events >25 mm changed to medium risk. These material changes were for Transmission Step-down to Municipal and Municipal Stations as well as Overhead loops as part of the feeder configuration and emergency response.

Table 6: Summary of interactions with material changes to risk scores

Climate Parameter	Threshold	Study Report Year	Number of Interactions by Risk Class		
			High	Medium	Low
Daily Maximum Temperature	40°C	2015	10	23	1
		2022	0	33	1
Ice Storm / Freezing Rain	25 mm ≈ 12.5 mm radial	2015	18	5	9
		2022	5	18	9

Individual material risk classification changes are outlined in Table 7 with references to specific adaptation options from the 2015 Study and report.

Table 7: Material risk classification changes and adaptation option outcomes

Climate Parameter	Asset No.	Infrastructure Class or Category	2015 Risk Score	2022 Risk Score	Change to Risk Score	2015 Study Adaptation Recommendation[2]
High Temperature (40°C)	**1**	**Transmission Step-Down to Municipal**				• Further study required to address gaps in data availability and data quality
	1.1	**Former Toronto**				
	1.1.1	Downtown core stations	42	**36**	↓	
	1.1.2	Downtown outer stations without a station	42	**36**	↓	
	1.1.3	Station (13.8 kV)	42	**36**	↓	
	1.2	**Horseshoe Area**				
	1.2.1	Station	42	**36**	↓	
	1.2.4	Station	42	**36**	↓	
	1.2.5	Station (27.6 kV)	42	**36**	↓	
	1.2.8	2 Stations	42	**36**	↓	
	1.2.9	Southwest Stations	42	**36**	↓	
	2	**Municipal Stations (divided by Geography)**				
	2.1	**Toronto Hydro to Toronto Hydro & Private ownership**				
	2.1.1	Former Toronto (indoor/outdoor)	42	**36**	↓	
	2.1.3	Toronto Hydro to private ownership	42	**36**	↓	

[2] Adaptation recommendations are from Table 7-1 of the 2015 Study.

Climate Parameter	Asset No.	Infrastructure Class or Category	2015 Risk Score	2022 Risk Score	Change to Risk Score	2015 Study Adaptation Recommendation[2]
Freezing Rain /Ice Storm (>25 mm)	**1**	**Transmission Step-Down to Municipal**				• Management actions to account for changes in the infrastructure capacity • Further study required to address gaps in data availability and data quality
	1.1	**Former Toronto**				
	1.1.3	Station (13.8 kV)	42	**36**	↓	
	1.2	**Horseshoe Area**				
	1.2.1	Station	42	**36**	↓	
	1.2.2	Station (13.8 kV)	42	**36**	↓	
	1.2.3	East Stations	42	**36**	↓	
	1.2.4	Station	42	**36**	↓	
	1.2.5	Station (27.6 kV)	42	**36**	↓	
	1.2.6	Station	42	**36**	↓	
	1.2.7	Northwest Station	42	**36**	↓	
	1.2.8	2 Stations	42	**36**	↓	
	1.2.9	Southwest Stations	42	**36**	↓	
	2	**Municipal Stations**				
	2.1	**Toronto Hydro to Toronto Hydro & Private ownership**				
	2.1.2	Horseshoe Area (indoor/outdoor)	42	**36**	↓	
	3	**Feeder Configuration: Underground**				• Management actions to account for changes in the infrastructure capacity • Remedial engineering actions which aim to strengthen or upgrade the infrastructure
	3.5	**Overhead**				
		Loop				
	3.5.4	4.16 kV	42	**36**	↓	
	6	**Human Resources**				• Management actions to account for changes in the infrastructure capacity
	6.1	Emergency Response	42	**36**	↓	

4 Discussion

The results presented in the preceding sections show the updated climate projection information reviewed does not result in any material increases to the risk scores presented in the 2015 Study. However, there are a few differences between the climate parameter probabilities and risk scores that merit further discussion.

While many of the climate parameter probabilities/frequencies have increased (see Appendix A), the climate parameter probability score for the study period provided in the 2015 Study was already at the highest possible level (7, or greater than 99% annual probability). As a result, any notable increases in the frequency of these climatic events based on the updated data are not reflected in this risk assessment. To address this issue, the latest PIEVC guidance, released in the High-Level Screening Guide (ICLR, 2022) would dictate that some of these parameters should be evaluated using the 'middle-baseline' approach.

In the middle-baseline approach, the future probability score is dependent on the projected percent change in climate parameter frequency compared to the baseline (with a default baseline probability score of 3). More specifically, the middle baseline approach dictates that a >10% increase in climate parameter frequency, would result in an increase in the probability score from 3 to 4, and a >50% increase would result in a score of 5. Based on this approach, we have identified the climate parameters where probability scores of 7 from the 2015 Study could not be increased and where the projected 2030s frequency changed by more than 10% compared to that presented in the 2015 report.

- High Daily Average Temperature >30°C (increase from 0.6 to 0.8 days/year)
- Heat Waves (increase from >1 to 2.6 days/year)
- High Nighttime Temperatures >23°C (decrease from 7 to 3 days/year)

Although the probability scores (and hence the associated risk scores) for the above climate parameters are unchanged from the 2015 Study, their associated adaptation measures may merit further study to evaluate whether they are sufficient to address the differences in climate parameter frequencies.

While we found a slight decrease in the number of infrastructure asset classes at high risk due to extreme heat (>40°C) events, the range in climate parameter probabilities over the study period is broad across the CMIP6 model ensemble, and the probability score is very close to being a 7 over the study period (90% probability of occurrence). Therefore, although the change materially decreases based on this analysis, we do not recommend relaxing any of the adaptation measures proposed in the 2015 Study.

The 2015 Study estimated the probability score of freezing rain/ice storms events (>25 mm) would increase in the 2030s. Updated climate projection information suggests the probability will remain steady over the study period. Although we do not have an ensemble of models to consider for this climate parameter, the literature investigated expressed ‘very low confidence’ in the projections, and therefore the probability could range widely. Therefore, although the change materially decreases, based on this analysis, we do not recommend relaxing any of the measures associated with freezing rain events >25 mm.

5 Limitations

The findings in this report are subject to several limitations. Section 2 discusses specific uncertainties associated with each climate parameter. Some overarching limitations are noted below.

- Stantec did not review the 2015 Study adaptation recommendations to assess if they were sufficient to protect infrastructure assets against the relevant climate hazard, as this would have been beyond the scope of this study. The results from this study could be used to evaluate which of the adaptation recommendations merit further review.
- Climate data is inherently uncertain. The climate parameter probabilities provided should be considered as high-level estimates of future conditions. The primary source of uncertainty in climate projections is the estimate of greenhouse gas emissions that will be observed over the current century. Additional sources of uncertainty include (but are not limited to) climate model parameterization, bias, and resolution.
- Some of the climate parameters investigated are associated with very high degrees of uncertainty, because they are difficult to constrain using the outputs from climate models. Stantec has reviewed recently published scientific literature and guidance to provide an estimate of likely future conditions.
- The severity scores, as well as the thresholds used to define risk and climate parameter probability classes and scores were not reviewed as part of this analysis. The thresholds are consistent with those applied in the 2015 Study.

6 Closure

This study has provided an update to the climate parameters described in the 2015 Study, using newly available CMIP6 climate model data. By analyzing the CMIP6 data, as well as recent scientific literature and guidance documents, Stantec has updated the estimated risk scores for Toronto Hydro's infrastructure assets by applying the same risk assessment framework as was applied in the 2015 Study. Some parameters (heat waves, and daily average temperatures >30°C) are expected to occur more frequently than projected by the 2015 study, however, these events were already considered to be 'certain' over the study period in the 2015 Study. The only climate parameter probability scores that changed as a result of this analysis include extremely hot days (>40°C), and 25mm freezing rain events, both of which are projected to occur less frequently over the study period than was estimated in the 2015 Study. Though these decreases resulted in a downgrading from high to medium risk for multiple infrastructure asset classes, we do not recommend relaxing any of the adaptation measures provided in the 2015 Study.

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APPENDICES

Appendix A – 2022 Climate Parameter Probability Update

Climate Parameter	Threshold	2015 Study								2022 Study								Study Period Probability Difference (2022-2015)
		Data Source	Annual Frequency			Probability Score			Study Period Probability (2015-2050)	Data Source	Annual Frequency - Corrected			Probability Score			Study Period Probability (2022-2050)	
			Baseline (1981-2010)	2030s (2021-2050)	2050s (2041-2070)	Baseline (1981-2010)	2030s & 2050s	Study Period (2015-2050)			Baseline (1981-2010)	2030s (2021-2050)	2050s (2041-2070)	Baseline (1981-2010)	2030s & 2050s	Study Period (2022-2050)		
Daily Maximum Temperatures	25°C	CMIP5 Ensemble (IPCC AR5)	66	84	106	7	7	7	100%	CanDCS-U6 Ensemble	66 (47 - 76)	86 (64 - 102)	110 (86 - 126)	7	7	7	>99%	No Change
Daily Maximum Temperatures	30°C	CMIP5 Ensemble (IPCC AR5)	16	26	47	7	7	7	100%	CanDCS-U6 Ensemble	16 (4 - 22)	28 (10 - 41)	50 (25 - 74)	7	7	7	>99%	No Change
Daily Maximum Temperatures	35°C	CMIP5 Ensemble (IPCC AR5)	0.75	3	8	6	7	7	100%	CanDCS-U6 Ensemble	0.8 (0 - 1.5)	2.8 (0 - 7)	9.2 (0.5 - 22.5)	6	7	7	>99%	No Change
Daily Maximum Temperatures	40°C	CMIP5 Ensemble (IPCC AR5)	0.01	0.3-2	1-7	1	4-7	7	~100%	CanDCS-U6 Ensemble	0.01 (0 - 0)	0.08 (0 - 0.1)	0.64 (0 - 1.98)	1	5	6	90%	Decrease
High Daily Avg. Temperature	30°C	CMIP5 Ensemble (IPCC AR5)	0.07	0.565	1.2	3	7	7	~100%	CanDCS-U6 Ensemble	0.07 (0 - 0.04)	0.75 (0 - 2.22)	4.31 (0 - 11.72)	3	7	7	>99%	No Change
Heat Wave	3-days with max temp over 30°C	CMIP5 Ensemble (IPCC AR5)	0.88	>1	>1	6	7	7	100%	CanDCS-U6 Ensemble	0.9 (0.2 - 3.3)	2.6 (0.9 - 5.9)	4.8 (2.9 - 8.3)	6	7	7	>99%	No Change
High Nighttime Temperatures	Nighttime low ≥23°C	CMIP5 Ensemble (IPCC AR5)	0.70	7	16	6	7	7	~100%	CanDCS-U6 Ensemble	0.7 (0 - 1.3)	2.6 (0.1 - 5.9)	10.7 (2.3 - 20.8)	6	7	7	>99%	No Change
Snowfall	Days w/ >10 cm	CMIP5 Ensemble (IPCC AR5)	1.5	Decreasing	Decreasing	7	7	7	100%	CanDCS-U6 Ensemble	1.4 (0.1 - 2.8)	1.2 (0 - 2.6)	0.9 (0 - 2.2)	7	7	7	>99%	No Change
Snowfall	Days w/ > 5cm	CMIP5 Ensemble (IPCC AR5)	5	Decreasing	Decreasing	7	7	7	100%	CanDCS-U6 Ensemble	5.2 (2.2 - 8.5)	4.4 (1.6 - 7.6)	3.1 (0.5 - 6)	7	7	7	>99%	No Change
Frost-Free Days	0°C	CMIP5 Ensemble (IPCC AR5)	229	249	273	7	7	7	100%	CanDCS-U6 Ensemble	229 (225 - 256)	249 (242 - 279)	278 (264 - 320)	7	7	7	>99%	No Change
Extreme Rainfall	100 mm in <1 day + antecedent	Kunkel et al. (2013)	0.04	Expected increase	Expected increase	2	3	6	~75%-85%	Cannon et al. (2020); CanDCS-U6 Ensemble	0.02	+11% rainfall intensity	+20% rainfall intensity	2	2	6	75%	No Change
Ice Storm/Freezing Rain	15 mm (tree branches)	Cheng et al. (2011, 2014)	0.11	0.13	0.16	3	3	7	>99%	McCray et al (2022); Jeong et al (2018); Jarret et al (2019); Cannon et al. (2020)	0.11	-2.2% in 1/20yr ice accretion	-7.7% in 1/20yr ice accretion	3	3	7	99%	No Change
Ice Storm/Freezing Rain	25 mm ≈ 12.5 mm radial	Cheng et al. (2011, 2014)	0.06	0.07	0.09	2	3	7	>95%	McCray et al (2022); Jeong et al (2018); Jarret et al (2019); Cannon et al. (2020)	0.06	-2.2% in 1/20yr ice accretion	-7.7% in 1/20yr ice accretion	2	2	6	96%	Decrease
Ice Storm/Freezing Rain	60 mm ≈ 30 mm radial	Cheng et al. (2011, 2014)	0.005	0.013	0.007	1	1	4	High: ~25% Low: ~8%	McCray et al (2022); Jeong et al (2018); Jarret et al (2019); Cannon et al. (2020)	0.005	-2.2% in 1/20yr ice accretion	-7.7% in 1/20yr ice accretion	1	1	4	23%	No Change
High Winds	70 km/h+ (tree branches)	Cheng et al. (2012); Cheng (2014)	21	N/A	25	7	7	7	100%	Cannon et al. (2020)	21	+0.7% in 10-yr wind speeds	+2.7% in 10-yr wind speeds	7	7	7	>99%	No Change
High Winds	90 km/h	Cheng et al. (2012), Cheng (2014)	2	N/A	>2.5	7	7	7	100%	Cannon et al. (2020)	2	+0.7% in 10-yr wind speeds	+2.7% in 10-yr wind speeds	7	7	7	>99%	No Change
High Winds	120 km/h	N/A	0.05	Likely Increase	Likely Increase	2	2	7	~85% or higher	Cannon et al. (2020)	0.05	+0.8% in 25-yr wind speeds	+3.4% in 25-yr wind speeds	2	2	7	76%	No Change
Tornado	EF1+	Brooks et al. (2014)	-	Unknown, no consensus	Unknown, no consensus	0	0	1	~0.6%	Cheng et al. (2013); Gensini et al. (2018); Sills et al. (2020)	-	Unknown, no consensus	Unknown, no consensus	0	0	1	~0.6%	No Change
Tornado	EF2+	Brooks et al. (2014)	-	Unknown, no consensus	Unknown, no consensus	0	0	0	~0.3%	Cheng et al. (2013); Gensini et al. (2018); Sills et al. (2020)	-	Unknown, no consensus	Unknown, no consensus	0	0	0	~0.3%	No Change
Lightning	Flash density per km km^2	Romps et al (2014)	1.12-2.24/yr/km^2	Expected increase, % unknown	Expected increase, % unknown	0-2	N/A	3-6	~50-70%(Lg); ~10-20% (Sm)	Romps et al (2014), Romps (2018), Finney et al. (2018)	1.43	1.43	1.43	1	1	6	55% (Lg)	No Change

Appendix B – 2022 Risk Scores for Interactions with Updated Climate Parameters

Climate Change Vulnerability Assessment Update
Appendix B – 2022 Risk Scores for Interactions with Updated Climate Parameters
November 18, 2022

	Infrastructure Class or Category	4	High Temperature 40°C							10	Freezing Rain/Ice Storm 25 mm ≈ 12.5 mm radial						
		Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change	Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change
1	**Transmission Step-down to Municipal**																
1.1	**Former Toronto**																
1.1.1	Downtown core stations	Y	7	6	5+	6	42	**36**	↓	N							
1.1.2	Downtown outer stations without a station	Y	7	6	5+	6	42	**36**	↓	N							
1.1.3	Station (13.8 kV)	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2	**Horseshoe Area**																
1.2.1	Station	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2.2	Station (13.8 kV)	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
1.2.3	East Stations	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
1.2.4	Station	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2.5	Station (27.6 kV)	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2.6	Station	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
1.2.7	Northwest Station	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
1.2.8	2 Stations	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2.9	Southwest Stations	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
2	**Municipal Stations**																
2.1	**TO Hydro to TO Hydro & Private Ownership**																
2.1.1	Former Toronto (indoor/outdoor)	Y	7	6	5+	6	42	**36**	↓	N							
2.1.2	Horseshoe Area (indoor/outdoor)	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
2.1.3	Toronto Hydro to private ownership	Y	7	6	5+	6	42	**36**	↓	N							
3	**Feeder Configuration: Underground**																
3.1	**Horseshoe Area: Dual Radial System**																
3.1.1	Submersible type	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.1.2	Vault type																
	Above ground	Y	7	6	3	3	21	**18**	↔	N							
	Below ground	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.1.3	Padmount Station	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.2	**Former Toronto: Dual Radial System**																

Climate Change Vulnerability Assessment Update
Appendix B – 2022 Risk Scores for Interactions with Updated Climate Parameters
November 18, 2022

Infrastructure Class or Category		4	High Temperature							10	Freezing Rain/Ice Storm						
		40°C								25 mm ≈ 12.5 mm radial							
		Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change	Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change
3.2.1	Submersible type	Y	7	6	3+	4	28	**24**	↔	Y	7	6	1+	2	14	**12**	↔
3.2.2	Vault Type																
	Above ground	Y	7	6	3+	4	28	**24**	↔	N							
	Below ground	Y	7	6	3+	4	28	**24**	↔	Y	7	6	1+	2	14	**12**	↔
3.2.3	Padmount Station	Y	7	6	3+	4	28	**24**	↔	Y	7	6	1+	2	14	**12**	↔
3.3	**Compact Loop Design**																
3.3.1	Former Toronto: Subway Type	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.4	**13.8 kV Network**																
3.4.1	Former Toronto	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.5	**Overhead**																
	Radial																
3.5.1	4.16 kV	Y	7	6	4+	5	35	**30**	↔	Y	7	6	6+	7	49	**42**	↔
3.5.2	13.8 kV Network	Y	7	6	4+	5	35	**30**	↔	Y	7	6	7	7	49	**42**	↔
3.5.3	27.6 kV	Y	7	6	4+	5	35	**30**	↔	Y	7	6	7	7	49	**42**	↔
	Loop																
3.5.4	4.16 kV	Y	7	6	4	4	28	**24**	↔	Y	7	6	6	6	42	**36**	↓
3.5.5	13.8 kV	Y	7	6	4	4	28	**24**	↔	Y	7	6	7	7	49	**42**	↔
3.5.6	27.6 kV	Y	7	6	4	4	28	**24**	↔	Y	7	6	7	7	49	**42**	↔
4	**Communications**																
4.1	Protection and control systems	Y	7	6	2	2	14	**12**	↔	N							
4.2	SCADA and Wireless Network	Y	7	6	1	1	7	**6**	↔	Y	7	6	1	1	7	**6**	↔
5	**Civil Structures**																
5.1	**Transmission and Municipal Stations**																
	Outdoor																
5.1.1	Equipment support	N								N							
5.1.2	Gantry	N								Y	7	6	1	1	7	**6**	↔
5.2	**Underground feeders: Former Toronto**																
5.2.1	Reinforced concrete cable chambers	N								Y	7	6	1+	2	14	**12**	↔

Infrastructure Class or Category		4	High Temperature							10	Freezing Rain/Ice Storm						
		40°C								25 mm ≈ 12.5 mm radial							
		Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change	Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change
5.2.2	Concrete vaults (reinforced)	N								Y	7	6	1+	2	14	**12**	↔
5.2.3	Underground cable ducts	N								N							
5.3	**Underground feeders: Horseshoe Area**																
5.3.1	Reinforced concrete cable chambers	N								Y	7	6	1	1	7	**6**	↔
5.3.2	Concrete vaults (reinforced)	N								Y	7	6	1	1	7	**6**	↔
5.3.3	Underground cable ducts	N								N							
6	**Human resources**																
6.1	Emergency Response	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓

Appendix C – 2015 Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

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

Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

June 2015

Image source: Toronto Hydro

Environment

Clean Air Partnership
75 Elizabeth Street
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Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

Application of the Public Infrastructure Engineering Vulnerability Assessment Protocol to Electrical Distribution Infrastructure

Final Report - Public

6031-8907

June 2015

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Revisions List

Revision #	Revised by	Date	Description of the revisions
1	AECOM	8 May 2015	Response to Toronto Hydro comments on Preliminary Report
2	AECOM	29 May 2015	Response to Toronto Hydro comments on Final Report

Signatures

Report prepared by: Sophie Potvin-Champagne, Eng. 1 June 2015

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Executive Summary

The current study aims to evaluate the vulnerability of Toronto Hydro's electrical distribution system within the City of Toronto to a changing climate by employing Engineers Canada's Public Infrastructure Engineering Vulnerability Assessment Protocol (PIEVC Protocol). This study is a high level screening analysis designed to determine where infrastructure vulnerabilities to climate change may be present, to suggest avenues for adapting infrastructure to climate change, and to identify areas of further study.

Electrical Distribution System under Study

Toronto Hydro distributes electricity across the City of Toronto, Canada's largest city and home to approximately 2.8 million people in 2014. Toronto Hydro serves approximately 740,000 customers in the City of Toronto and owns approximately $3 billion dollars in assets, including over 170 transformer stations, approximately 29,000 km of overhead and underground wires, 20,000+ switches, 60,000+ transformers and 176,000+ poles.

The study period of this assessment was 2015 to 2050. A "system" level approach was employed to assess the impacts of climate change on the various parts of the electrical distribution system. This approach divided the distribution system into six major asset categories: stations, feeders, communications systems, civil structures, auxiliary mechanical systems and human resources. Asset categories were assessed based on their general characteristics (e.g. typical, representative or common electrical or mechanical configurations, standards, equipment). For example, this analysis focused on how systems designed to current (post 2000) CSA standards may interact with the climate parameters being considered. Changes to the electrical system considered in this assessment included the planned transition from rear lot to front lot power lines, the partial phase out of 4.16 kV system, some demand and supply projections[1], and replacement of non-submersible equipment. The streetlighting system and systems serving the Toronto Transit Commission (TTC) were not within the scope of this study.

Toronto Hydro documentation, electrical standards and consultations with Toronto Hydro staff (through ongoing communications and two workshops) were all used to help identify and describe asset categories, general characteristics and sensitivities to climate related stresses (climate parameters[2]).

Climate Parameters

20 climate parameters including high temperature, heavy rainfall, snowfall, freezing rain, high winds and lightning were considered in this assessment. Relevant climate parameters and threshold values at which infrastructure performance would be affected were identified through a literature review, consultations with Toronto Hydro staff and analysis of past outage events.

The probability of a climate parameter occurring during the study period was determined using global climate modelling (GCM) data obtained from the Intergovernmental Panel on Climate Change's 5th Assessment Report (IPCC AR5). In many cases, this information was validated or refined through the use of regional climate modelling data, statistical downscaling and climate analogues.

The probability of a climate parameter occurring is expressed both as a study period probability value (i.e. what is the probability of a climate parameter occurring sometime between 2015 – 2050) and an annual probability value centred around the 2030's and 2050's (i.e. what is the annual probability of a climate parameter occurring around

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[1] It should be noted that city-wide land use changes (high rises, condo development and population growth) were not included in the analysis, due to the scope of such an undertaking and the complexity of information required. Vulnerabilities were determined based on the assumption that gradual population growth would generally be accommodated by corresponding growth of Toronto Hydro systems under business as usual practices without the added stress of climate change.

[2] A climate parameter is defined by the PIEVC Protocol as a specific set of weather conditions or climate trends deemed to be relevant to the infrastructure under consideration. The parameter may be a single variable, such as mean monthly temperature, or a combination of variables, such as low temperature combined with rainfall.

the 2030's and 2050's). Examining both annual and study period probability was useful for understanding vulnerabilities that may stem from events which could occur on an annual basis (e.g. high temperature) against those which could occur less than annually, but have the potential to cause significant damage to the system sometime during the 35 year study period (e.g. ice storms, high winds, tornadoes). The list of climate parameters considered in this study is shown in table ES-1.

Table ES-1 Climate Parameters and Probability of Occurrence

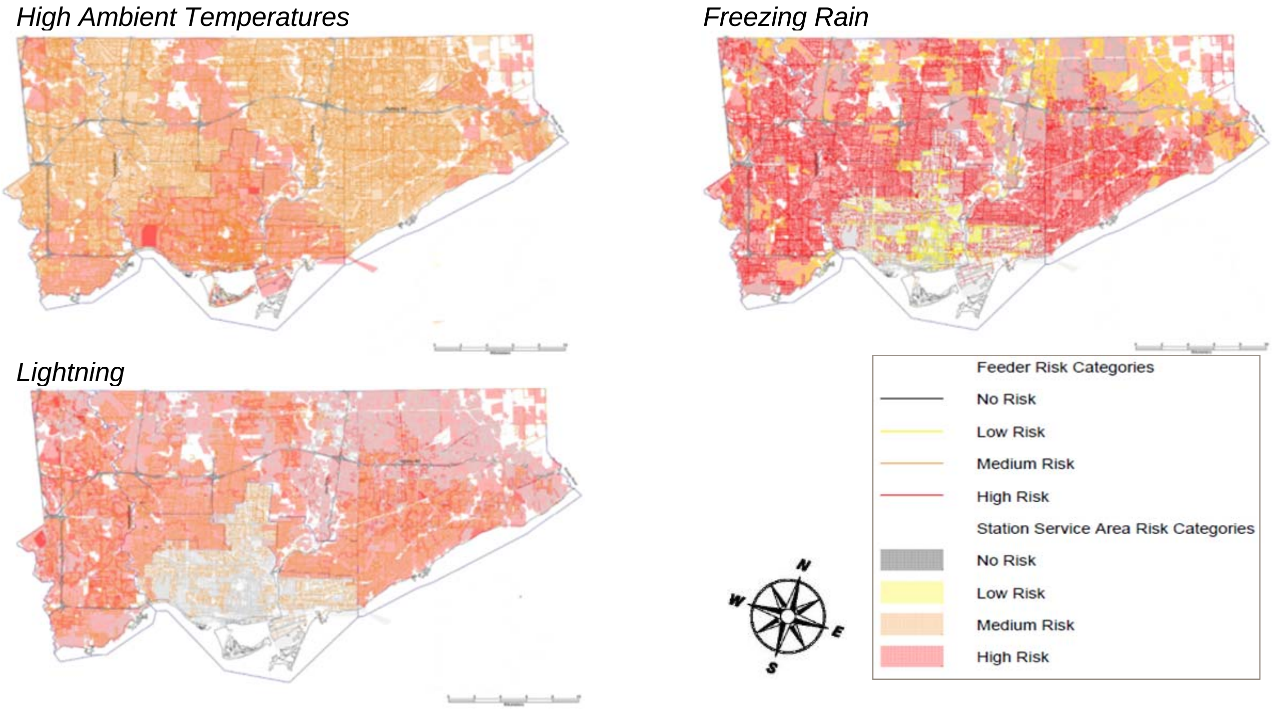
Climate Parameter		Annual Probability (Historical; **Projected 2030's and *2050's***)	Probability of Occurrence Study Period (2015-2050)
Daily Maximum Temperatures	25°C	66 per year; **84 per year**, ***106 per year***	100%
	30°C	16 per year; **26 per year**, ***47 per year***	100%
	35°C	0.75 per year; **3 per year**, ***8 per year***	100%
	40°C	~0.01 per year; **0.3 to 2 days per year**, ***1-7 days per year***	~100%
High Daily Avg. Temperature	30°C	0.07 per year; **N/A, *1.2 days per year***	~100%
Heat Wave	3 days max temp over 30°C	0.88 per year; **>1 for both**	100%
High Nighttime Temperatures	Nighttime low ≥23°C	0.70 per year; **7 per year, *16 per year***	~100%
Extreme Rainfall	100 mm in <1 day + antecedent	0.04 per year; ***extreme precipitation expected ↑, percentage unknown***	~75%-85%
Ice Storm/Freezing Rain	15 mm (tree branches)	0.11 per year; **>0.13 per year, *>0.16 per year***	>99%
	25 mm ≈ 12.5 mm radial	0.06 days per year; **>0.07 per year, *>0.09 per year***	>95%
	60 mm ≈ 30 mm radial	Upper bound of estimate: 0.007 events per year; **>0.008 per year; *>0.01 per year*** Lower bound of estimate: 0.002 events per year; **> 0.0023 per year; *0.003 per year***	High: ~25% Low: ~8%
High Winds	70 km/h+ (tree branches)	21 days per year***;* N/A, *24 to 26 per year***	100%
	90 km/h	2 days per year; **N/A, *>2.5 per year***	100%
	120 km/h	~0.05 days per year; ***likely ↑, but % unknown***	~85% or higher
Tornado	EF1+	1-in-6,000; ***Unknown, no consensus***	~0.6%
	EF2+	1-in-12,000; ***Unknown, no consensus***	~0.3%
Lightning	Flash density per km km^2	1.12 to 2.24 per year per km^2; ***Expected increase, % change unknown***	~50-70%(Lg); ~10-20% (Sm)
Snowfall	Days w/ >10 cm	1.5 days per year; ***Trend decreasing but highly variable***	100%
	Days w/ > 5cm	5 days per year; ***Trend decreasing but highly variable***	100%
Frost		229 frost free days; **249 frost free days, *273 frost free days***	100%

Assessing Vulnerability

The vulnerability of the electrical system to climate parameters was determined using a risk based framework (probability of occurrence of a climate parameter coupled with the severity/consequence of the impact on the system). All high risk interactions were deemed as vulnerabilities for Toronto Hydro. Medium risk interactions were evaluated in further detail through an engineering analysis. Those which exhibited sensitivities or consequences similar to high risk interactions were also deemed as vulnerabilities for Toronto Hydro. Finally, interactions rated as low risk were generally judged as not being a significant issue or vulnerability for Toronto Hydro.

A mapping of the risk ratings was also completed as part of this study and represents a useful first approximation of spatial nature of climate change vulnerabilities to the electrical system. The mapping exercise provides additional information on how vulnerabilities stemming from stations can combine with vulnerabilities to feeder systems. In some cases, vulnerabilities stem primarily from station assets, while in other cases, both station and feeder vulnerabilities to weather events contribute to an area of greater vulnerability within the city. This mapping information can be easily combined with other layers of information such as technical hazard information (e.g. flood mapping), critical building and infrastructure locations (e.g. emergency resource centres, hospitals, transportation networks) and social vulnerability indices (e.g. age, income, population density, etc.) from other sources (e.g. TRCA, City of Toronto) to support further mapping studies and in depth analyses.

Figure ES-1 Example Maps Based on Risk Ratings for High Heat, Freezing Rain and Lightning



This study found that distribution system vulnerabilities to a changing climate were divided into five groups based on how climate parameters affect the system.

High Ambient Temperatures – Station and Feeder Assets

High ambient temperatures create problems for the distribution system because of the compounding effect of high demand (e.g. for cooling) and high ambient temperature affecting power transformer capacity and electrical transmission efficiency. Two climate parameters were of most significant concern, daily maximum temperatures exceeding 40°C (excluding humidity) and daily average temperatures exceeding 30°C. For these climate parameters, the analysis found that such extreme temperatures have occurred rarely in the past, but are projected to occur almost semi-annually by the 2030's, and annually by the 2050's. It is anticipated that vulnerability to high heat events will be concentrated in the Former Toronto area, although there are several horseshoe station service areas which would also be vulnerable.

Freezing Rain, Ice Storms, High Wind and Tornadoes – Overhead Station and Feeder Assets

Freezing rain, ice storms, high wind and tornado events can cause immediate structural issues for overhead station and feeder assets, as they have the capacity to exceed the design limits of equipment and their supports. Outages may result from damage to equipment arising from direct forces applied by climate parameters (e.g. wind, ice weight) or by other objects (e.g. tree branches, flying debris). Toronto Hydro has experienced problems related to freezing rain, ice storms (up to 25 mm) and high winds (up to 90 km/h) in the past. These events are projected to continue in the future, but continue to occur on a less than annual, or even decadal frequency. Nonetheless, the damages caused by these kinds of events can be severe, and mostly affect outdoor station and feeder assets, much of which is concentrated in the horseshoe service area.

Extreme Rainfall – Underground Feeder Assets

Extreme rainfall events may potentially flood underground feeder assets. These vulnerabilities are largely concentrated in the Former Toronto and northeastern horseshoe areas. Toronto Hydro is aware of these issues in relation to its assets and has programs to replace non-submersible equipment with submersible type equipment, to relocate equipment where possible. However, due to the large quantity of underground feeder assets across the city, replacement and reinforcement of underground assets will be a gradual and ongoing activity for Toronto Hydro over the study period. As such, some underground feeder assets may remain an area of vulnerability for Toronto Hydro.

Snowfall, Freezing Rain - Corrosion of Civil Structures

The degradation of civil structures (i.e. concrete and steel), which is accelerated by humidity and the presence of de-icing salts, was identified as a potential area of vulnerability to climate change. Corrosion is already an ongoing issue for Toronto Hydro. As such, current assets have a design lifespan which accounts to a great extent for corrosion issues. However, it is not clear from this study whether the climate change stresses will exacerbate this problem. While snowfall days are generally expected to decrease with a warming climate, they will continue to occur annually through to the 2050's. As a result, and in combination with freezing rain events, de-icing salts will also be applied annually through the study horizon, and corrosion will continue to be an ongoing preoccupation. Nonetheless, it should be emphasized that corrosion represents a long-term and on-going vulnerability for Toronto Hydro.

Lightning – Overhead Feeder Assets

Based on workshop feedback and an examination of Toronto Hydro's interruption tracking system's (ITIS) outage data, Toronto Hydro recognizes that lightning impacts are a significant source of outages on the distribution system today. While there have been advances in predicting lightning activity, there was insufficient data available on lightning strike intensity and arrester performance to suggest how future lighting activity may affect the electrical system. For these reasons, this study suggests that lightning strikes will continue to be an area of vulnerability.

Adaptation Options and Areas of Further Study

This study provides high level adaptation options under the themes of engineering actions, management actions, monitoring activities and further study. Generally, for high heat related climate parameters, Toronto Hydro could further investigate avenues to enhance the system's capacity to deal with higher demand under high temperature conditions, especially since extreme heat events are projected to occur on a semi-annual to annual basis by the 2030's and 2050's. On climate events causing structural damage issues (i.e. freezing rain, ice storms, high winds and tornadoes), adaptation options include optimizing emergency response and service restoration, as well as infrastructure hardening and burying infrastructure. While the latter engineering-type solutions are relatively capital intensive, asset renewal cycles provide excellent opportunities to consider these types of upgrades. This study also recommends that Toronto Hydro continue monitoring the occurrences and impacts of major freezing rain, high wind and tornado events on the system, as well as the science of climate change projections. This multi-faceted approach provides Toronto Hydro with greater flexibility in managing vulnerabilities related to these types of extreme climate events.

Other potential options to address identified vulnerabilities include continued monitoring and evaluation of climate change projection science, monitoring impacts of a changing climate on certain asset classes, evaluating the need to strengthen or defend certain infrastructure and equipment from climate parameters, and enhancing emergency response and service restoration practices.

Acknowledgements

This study was completed with support from Natural Resources Canada. It was produced through its Adaptation Platform Electrical Sector Working Group[3]. AECOM would also like to acknowledge Engineers Canada for the technical support, participation and for the use of its Public Infrastructure Engineering Vulnerability Committee (PIEVC) Protocol. The Toronto region's WeatherWise Partnership is also acknowledged for its work on bringing the issue of climate related threats on electrical infrastructure to the forefront, and for its support in bringing about this study. AECOM would like to thank the Clean Air Partnership for the opportunity to undertake this study.

AECOM would also like to acknowledge Toronto Hydro staff for their time and effort in providing information about their system, participating in workshops and meetings, providing insight into the functionality of their system, and reviewing documents and reports. Without their valuable contributions, this study could not have proceeded.

[3] For more information on climate change impacts and adaptation, please visit adaptation.nrcan.gc.ca" (or for French language publications/sites: "adaptation.rncan.gc.ca").

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List of Acronyms

CAP	Clean Air Partnership
GCM	Global climate model
GIS	Geographic Information Systems
HONI	Hydro One Networks Inc.
ITIS	Interruption Tracking System
NRCan	Natural Resources Canada
OPG	Ontario Power Generation
PIEVC	Public Infrastructure Engineering Vulnerability Committee
Protocol	The climate change based public infrastructure vulnerability assessment developed by the PIEVC and Engineers Canada
RCM	Regional climate model
RCP	Representative concentration pathway
RSI	Risk Sciences International
THESL	Toronto Hydro-Electric System Limited
TTC	Toronto Transit Commission

1 Study Context

1.1 Introduction and Mandate

In 2012, Engineers Canada partnered with the Clean Air Partnership (CAP) and Toronto Hydro to evaluate the risks of climate change on Toronto Hydro's electrical distribution infrastructure in the City of Toronto. At that time, CAP mandated AECOM and Risk Sciences International (RSI) to undertake a Public Infrastructure Engineering Vulnerability Assessment Protocol (PIEVC Protocol, or the Protocol)[4] based study on select components of Toronto Hydro's electrical distribution system to historical climate. That study, named the Toronto Hydro-Electric System PIEVC Pilot Case (pilot case study), was meant to demonstrate the applicability of the Protocol to electrical systems. The pilot case study was also envisioned as the first of a two-phase project to assess climate change related vulnerabilities to electrical systems. The pilot case study was completed at the end of summer 2012 (AECOM and RSI, 2012).

In summer 2013, CAP and Toronto Hydro elected to pursue the second phase of the climate change assessment with support from Natural Resources Canada's (NRCan) "Enhancing Competitiveness in a Changing Climate" program. NRCan's program is designed to facilitate the development and sharing of knowledge, tools and practices which assist decision-makers in the analysis and implementation of climate change related adaptation measures. CAP, once again mandated AECOM and RSI to carry out the Phase 2 climate change vulnerability assessment (Phase 2 study). The Phase 2 study is the subject of the current report.

1.2 Methodology and Approach

The Phase 2 study again employs the Protocol as the framework for the climate change analysis. The Protocol is composed of five steps:

- Step 1 – Project Definition;
- Step 2 – Data Gathering and Sufficiency;
- Step 3 – Risk Assessment;
- Step 4 – Engineering Analysis;
- Step 5 – Recommendations and Conclusions.

In contrast to the pilot case study, the scope of Phase 2 study was extended to include most of Toronto Hydro owned electrical distribution infrastructure and civil support structures across the City of Toronto. Toronto Hydro's streetlighting system and electrical systems for the Toronto Transit Commission were not within the scope of the present study. Anticipated climate changes and impacts at the 2030 and 2050 time horizons were evaluated. Most of the activities prescribed by the Protocol were completed as part of Phase 2 with the exception of a site visit. The triple-bottom line adaptation solutions development module, an optional undertaking in the PIEVC Protocol, was also not completed as part of Phase 2 of this study[5].

As part of the activities of Phase 2, two workshops were held with Toronto Hydro staff. The first workshop was held on July 3, 2014 in Toronto Hydro's offices in Toronto. At this workshop, an overview of the infrastructure and climate components (Steps 1 and 2 of the Protocol), were presented for discussion and validation with Toronto Hydro staff. On October 10, 2014, a second workshop was held to validate the risk assessment completed by AECOM and RSI (Step 3 of the Protocol).

4 The Protocol is a structured and documented methodology for a screening level assessment of infrastructure vulnerability to a changing climate, and for developing adaptation solutions to identified vulnerabilities. The Protocol, currently in version 10, also allows users to evaluate the vulnerabilities stemming from current climate to the infrastructure as part of the overall assessment.

5 The triple-bottom line adaptation solutions development module guides users in the development and screening of potential solutions to address the impacts of climate change identified in the preceding steps of the Protocol. It was not in the scope of the current study.

The components of the electrical distribution system (e.g. stations, power lines, transformers, switches, supports) under study are highly interdependent, and failures in one part of the system may result in interrelated structural, electrical or functional issues in other portions of the system (e.g. failures in poles may bring down power line and transformers, electrical faults may cause the system to lose protection, control or redundancy). For this reason, the study of electrical systems cannot be examined solely on the basis of its individual pieces or classes or equipment. This study adopts a *systems level approach*[6] to examining the climate change risks to the extensive, complex and interdependent components of Toronto Hydro's electrical distribution system. This approach divides the electrical distribution system into six major systems categories encompassing different individual components and classes of equipment. This generalization of electrical components into major systems categories facilitates an analysis that considers system dependencies and redundancies.

However, by generalizing the system into major systems categories, the granular detail of the system and its components (e.g. site specific characteristics, unique or individual pieces of equipment) may not be adequately captured. Therefore, to complete a reasonable study of the entire electrical distribution system, this study has made assumptions, informed by input from Toronto Hydro staff, about the types and classes of equipment and components typically found within each category. While the loss of granular detail may mask localized issues and vulnerabilities, it does allow this project to provide the first climate change based vulnerability assessment of electrical distribution infrastructure. This can help prioritize future investigations, resources and investment on vulnerable systems and their components in order to enhance the resilience of the electrical system.

1.3 Structure of this Report

This report is divided into seven chapters, including the present one. They are:

- Chapter 1: Study Context;
- Chapter 2: Description of the Infrastructure;
- Chapter 3: Assessment of Climate Changes;
- Chapter 4: Vulnerability Assessment Methodology;
- Chapter 5: Assessment Results;
- Chapter 6: Engineering Analysis; and,
- Chapter 7: Conclusions.

Note that Chapter 3, Assessment of Climate Changes and **Appendix B** and **C**, were authored by Risk Sciences International in consultation with AECOM study authors.

[6] This is in contrast to the component level analysis approach which was employed in the pilot case study.

2 Description of the Infrastructure

2.1 Study Area

The Phase 2 study covers Toronto Hydro's electrical distribution infrastructure and supporting civil infrastructure within the boundaries of the City of Toronto. Toronto Hydro distributes electricity across the City of Toronto, Canada's largest city, the provincial capital of Ontario, and home to approximately 2.8 million people (City of Toronto, 2014). The City of Toronto is bordered by the municipalities of Mississauga to the west (in Peel Region), Vaughan and Markham to the north (in York Region), and Pickering to the east (in Durham Region).

The City of Toronto covers approximately 641 km^2 on the northwestern shore of Lake Ontario (City of Toronto, 2014). The city's topography slopes gradually from the lakeshore, approximately 75 m above sea level to 200 m above sea level at its highest point along its northern border (City of Toronto, 2014). Three river systems cross the City of Toronto and flow into Lake Ontario. The Humber River lies on the west side of the City. The Don River essentially crosses the middle of the City of Toronto and flows into Lake Ontario just east of downtown. Finally, the Rouge River crosses the city's eastern edge. These rivers, their tributaries and creeks total about 307 km of water courses and punctuate the City's generally flat landscape with ravines.

The City lies at the eastern edge of the Carolinian Forest zone. The City contains approximately 10 million trees, approximately 4 million of which are publically owned. Of the latter, there are approximately 600,000 trees along streets and public right of ways, and another 3.5 million trees in parks, ravines and other natural areas of the city (City of Toronto, 2014).

2.1.1 Major Systems Categories Under Study

In 2014, Toronto Hydro's electrical distribution system served approximately 740,000 customers, of which around 658,000 were residential customers. The components of the Toronto Hydro's electrical distribution system are extensive, covering approximately $3 billion dollars in assets, including over 170 transformer stations of different classes, 29,000 km of overhead and underground wires, 20,000+ switches, 60,000+ transformers and 176,000+ poles (Toronto Hydro, 2014b). The present study covers most of Toronto Hydro's electrical distribution infrastructure and civil support structures, with the exclusion of its streetlighting system, and systems serving the Toronto Transit Commission (TTC). The electrical distribution system was divided into six *major systems categories* for the purposes of this study: transmission stations, feeder configurations, system communications, civil structures, mechanical auxiliaries and human resources. Figure 2-1 provides a schematic overview of the systems under study. The *major systems categories* are described hereafter, and hypotheses and generalizations that were made to facilitate the *system level analysis* approach are explained in this chapter. Supporting detail is included in Worksheet 1 of **Appendix H**.

This analysis divides the City of Toronto into two areas: the Former Toronto area and horseshoe area. This distinction is made because most of the legacy equipment is usually found in downtown Toronto and while equipment of newer design can usually be found in the horseshoe area. As such, the *major systems categories* (with the exception of human resources) are also separated between the Former Toronto area (which represents the downtown and inner city) and the horseshoe area (which covers the outlying suburbs). Figure 2-2 shows the division between the Former Toronto area (in green) and the horseshoe area (in blue).

Information about the *major systems categories* was drawn from three principal sources:

- *Overview of the Toronto Hydro Distribution Systems*. Toronto Hydro-Electric System Limited, 2014, Power point 203 p.
- *Overview of the Toronto Area Transmission Systems and Toronto Hydro Distribution Systems*. Toronto Hydro-Electric System Limited, 2014, Power point 121 p.

- System Expansion and Studies Section System Reliability Planning Department. *Toronto Hydro Distribution System Planning Guidelines.* Toronto Hydro-Electric System Limited, 2007, 22 p.

Figure 2-1 Major System Categories Under Study

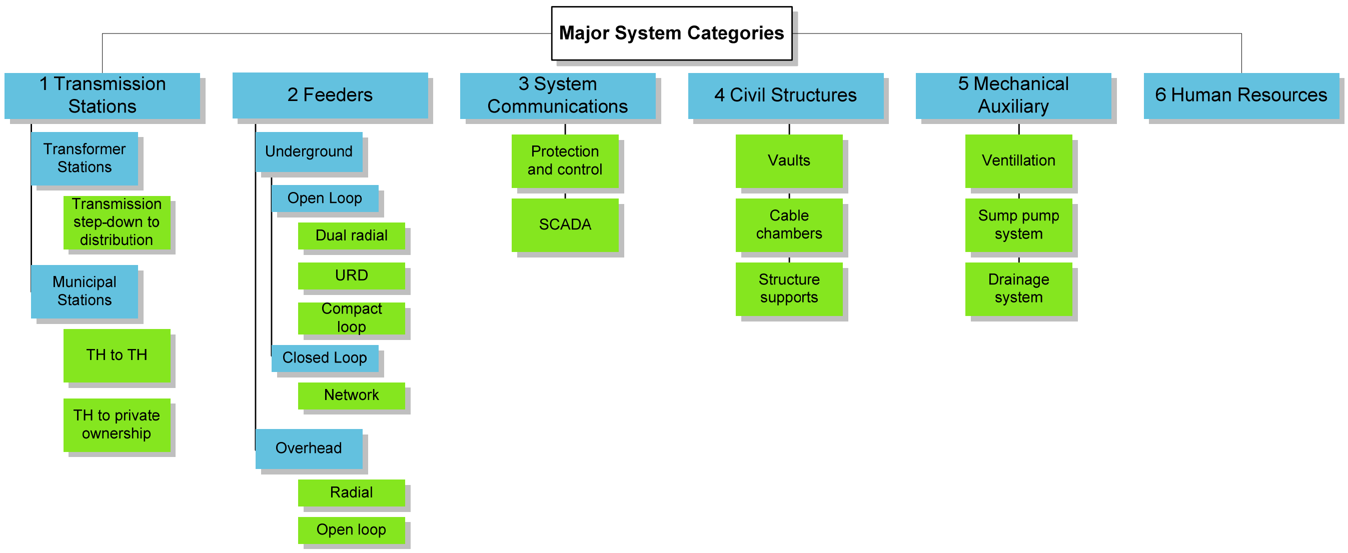
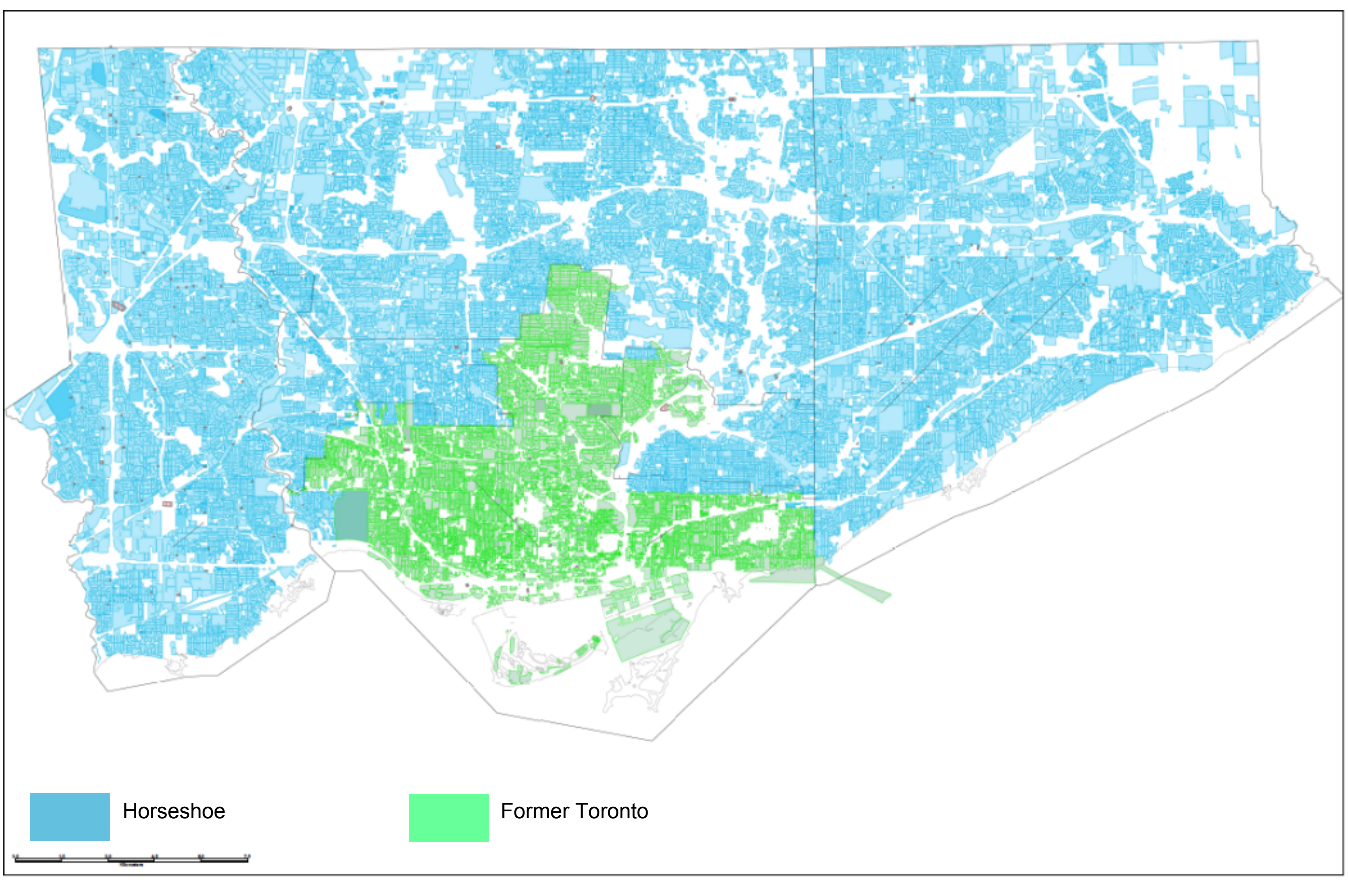


Figure 2-2 City of Toronto Study Area



2.2 General System Overview

The electric power system of the province of Ontario is a large interconnected electrical system of generating, transmission, and distribution infrastructure. Generating stations in Ontario are either privately or publicly owned. From the generation stations, the electricity is transmitted throughout the province over high voltage transmission lines, the majority of which is owned by Hydro One Networks Inc. (HONI). The electricity is then distributed to customers by local distribution companies like Toronto Hydro (Figure 2-3).

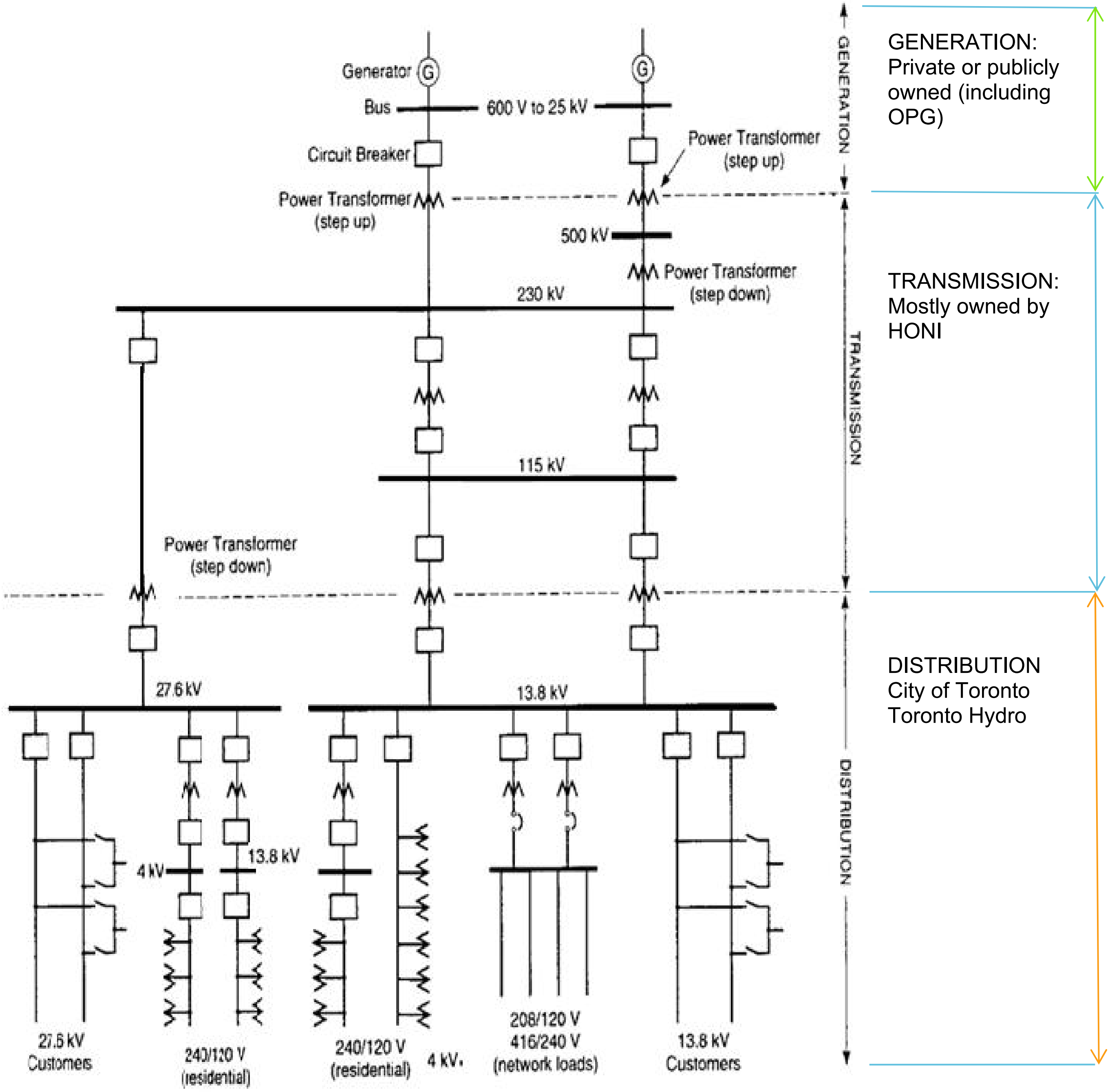
In the case of the City of Toronto, 230 kV and 115 kV transmission lines owned and operated by HONI bring power to the city. The 230 kV transmission lines mostly serve the horseshoe area, while the 115 kV lines serve most of the Former Toronto area. The 115 kV transmission lines are supplied from three major sources: Leaside station (230/115 kV step down) from the east, Manby station (230/115 kV step down) from the west, and by one generating station located within city limits, the Portlands Energy Centre (PEC) owned by Ontario Power Generation (OPG). PEC generates electricity through three natural gas turbine generators.

Presently, there are 35 transmission stations that step down high voltage currents (230 kV and 115 kV) to the distribution system voltages used by Toronto Hydro (i.e. 27.6 kV and 13.8 kV) (Figure 2-4). The equipment within these stations is owned by either Hydro One or Toronto Hydro, with the exception of Cavanagh station, where all equipment is owned by Toronto Hydro. The division of equipment ownership varies by station. However, since transmission stations are critical, first points of entry of electricity into the city’s distribution network, this study considers all equipment within the transmission station, since equipment failure within the station, irrespective of ownership, may compromise its function.

From transmission stations, Toronto Hydro distributes electricity via a network of underground and overhead feeder systems at voltages of 27.6 kV and 13.8 kV. A third distribution voltage level of 4.16 kV, a legacy from historical distribution practices, also operates in the city. The 4.16 kV network is supplied by transformation of 27.6 kV or 13.8 kV feeds at Toronto Hydro owned municipal transformer stations. These three distribution voltages will remain in service for the duration of the Phase 2 study period, even though many of the 4.16 kV power lines are gradually being converted to 13.8 kV and 27.6 kV lines.

This electrical distribution infrastructure is connected via communications systems which afford control and protection of electrical equipment from damage or faults. This system is critical to the operation of the electrical system and is part of this study. In addition, this study considers all civil structures that support the electrical equipment and all mechanical equipment inside underground vaults (ventilation, sumps and pumps). A last category includes all human resources operating and managing Toronto Hydro distribution system.

Figure 2-3 Typical Electric Power System



Source: (Toronto Hydro, 2014d)

Figure 2-4 Transmission Stations

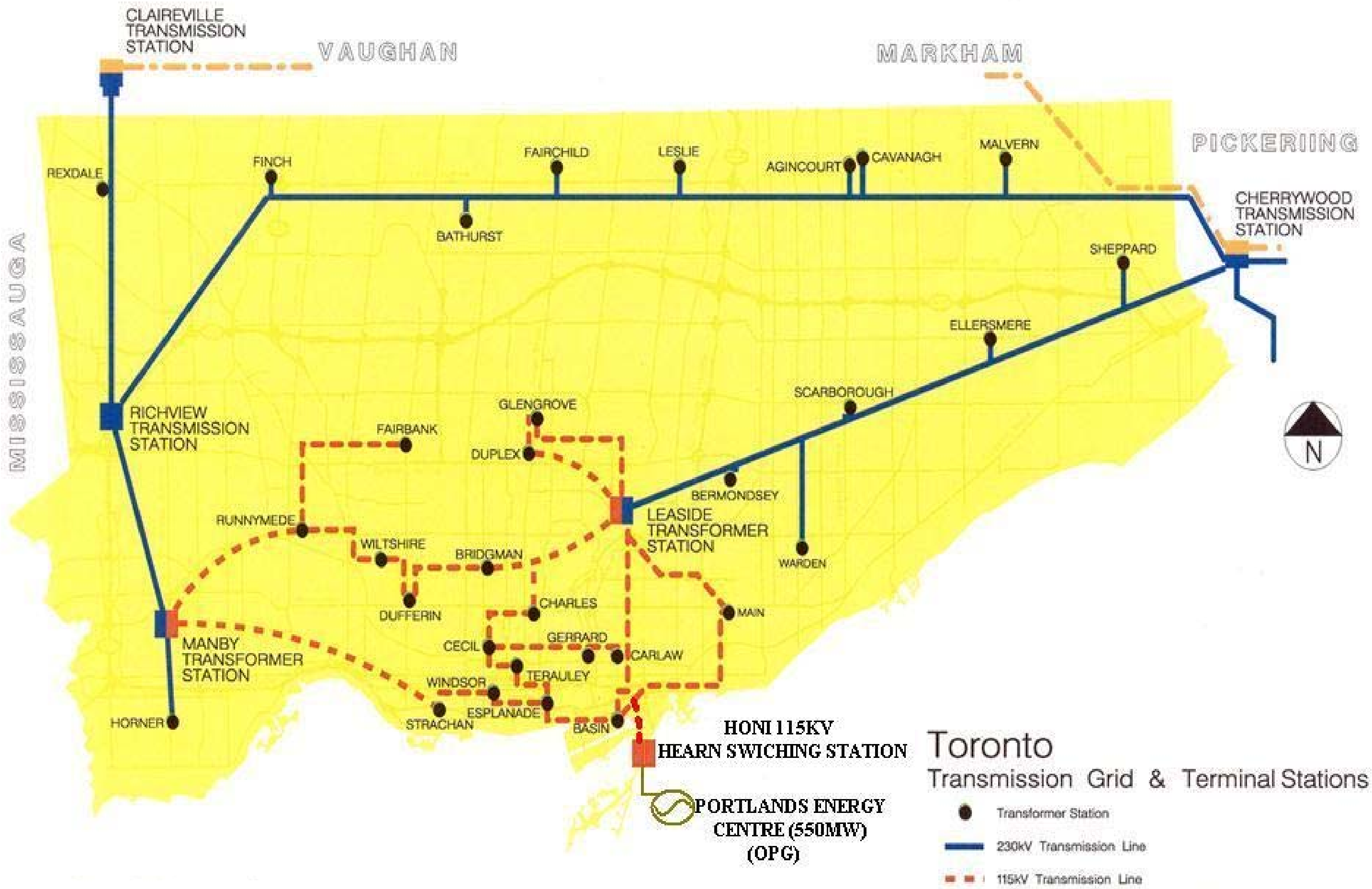


Figure source: (Toronto Hydro, 2014d)

2.3 Substations

2.3.1 Transmission Stations

At the moment, there are 35 transmission stations located in the City of Toronto. Most transmission stations located in the downtown and inner city have primary voltages at 115 kV and step-down to 13.8 kV. In the horseshoe area, the primary voltage is 230 kV and stepped-down to 27.6 kV (most) or 13.8 kV (some). The table below illustrates the list of stations that are divided into the two main service areas, and six sub-service areas[7] (Table 2-1).

[7] Stations have been grouped into these service areas by Toronto Hydro due to:
- Similarity of historical development and presumed potential for future development;
- Theoretical potential for permanently transferring load between neighbouring stations on an operational basis and/or through capital projects;
- Statistical correlation (coefficient of determination, R2) of the overall area growth rate to actual historical peak loads in the area (relative to potential alternative area groupings).

Table 2-1 Transmission Stations and Service Areas[8]

Service Area *(Voltage step down)*	Number of Stations
Former Toronto	
Downtown core *(115 kV/13.8 kV)*	6
Downtown outer *(115/13.8 kV, 230/115 kV, 115/27.6 kV)*	11
Horseshoe	
North Stations *(230/27.6 kV)*	2
East *(230 kV/27.6 kV, 230/115 kV)*	10
Northwest *(230 kV/27.6 kV)*	4
Southwest *(230/27.6 kV, 230/115 kV)*	2

In the Former Toronto area, there are no station ties between station service areas to allow for the transfer of some feeder loads from one station to another. In the horseshoe area, there are existing station ties available to allow the transfer some feeder loads from one station to another.

In the horseshoe area, the transmission stations are considered “outdoor”, as all equipment’s are exposed to the elements. A control building containing weather sensitive equipment and operators control room is located adjacent to the station. In the Former Toronto area, most stations are configured with equipment located indoors. The entire transmission station is surrounded by fences or walls for public safety.

All stations are essentially based on the Dual Element Spot Network (DESN) design configuration. Typically DESN has two power transformers with 230 kV or 115 kV primary windings, two 27.6 kV or 13.8 kV secondary windings and two buses.

By 2016, the Copeland Station (a gas insulated station) will be brought into service in the Former Toronto area. Gas Insulated Stations occupy less space than air insulated stations of comparable capacity. The gas used for insulation in the Copeland Station is Sulfur Hexafluoride (SF6).

<u>Typical equipment – Transmission Stations</u>

While each of the 35 transmission stations have site specific characteristics, representative and typical equipment found in all stations are:

[8] Station names have been excluded from this version of the report.

- Power transformers
- Lightning arresters
- Current and voltage transformers (instrument transformers)
- Disconnect-switches or interrupters (loadbreak switches)
- Circuit Breakers
- Medium voltage switchgears
- Bus bars
- Transmission station configurations: double bus - double breaker configuration, double bus - single breaker, double bus - double breaker or double bus and one and a half breakers.

A picture of a typical transmission station yard is shown in Figure 2-5.

Figure 2-5 The Station Yard at Cavanagh Transmission Station

Picture source: (Toronto Hydro, 2014a)

Note that this station *major systems category* does not include civil structures or protection and control systems. These other critical infrastructure components which form part of the transmission station are described under separate *major systems categories* below.

2.3.2 Municipal stations

The municipal stations are divided into two sub-categories. First, "Toronto Hydro to Toronto Hydro" municipal stations step down from 27.6 kV to 13.8 kV or to 4.16 kV in the Horseshoe Area, and in the Former Toronto area from 13.8 kV to 4.16 kV. There are also smaller transformer stations located on the sites of Toronto Hydro customers with high load demands. These stations are called "Toronto Hydro to Private ownership" stations in this study.

Toronto Hydro is converting its 4.16 kV voltage level over time to 13.8 kV and 27.6 kV because of age, loss minimization, equipment inventory reduction, and required or projected future load growth (Toronto Hydro, 2007). Toronto Hydro estimated that by 2030, 50% of the 4.16 kV equipment will be converted in the Horseshoe Area and all of it will be phased out in the Former Toronto area. By 2050, Toronto Hydro is expected to have replaced 70% of the 4.16 kV overhead power lines in the Horseshoe (Hypotheses issued in Workshop 1, 2014).

Toronto Hydro to Toronto Hydro

There are around 169 municipal stations (27.6 kV/ 13.8kV or 27.6 kV/13.8 kV / 4.16 kV) within the City of Toronto. Approximately 82 municipal stations are located entirely within a building, and these indoor stations are mostly located in the Former Toronto area. The remaining stations have some or all equipment located outdoors. These stations are classified as outdoor stations for the purposes of this study, and most are located in the horseshoe area. Figure 2-6 shows a picture of a typical outdoor station located in a residential area. For the purpose of this study, it is assumed that all Former Toronto area municipal stations are indoors, while horseshoe stations are outdoors. For those few outdoor stations in the Former Toronto area, their vulnerability will be identical to the outdoor stations in the horseshoe area.

Figure 2-6 Residential Area MS (front and rear views)

Figure source: (Toronto Hydro, 2014a)

Toronto Hydro to Private Ownership

Toronto Hydro to Private Ownership stations supply large loads at low voltages to private customers. The station is located on private property inside a closed room. Most of these stations are owned by Toronto Hydro, although some are owned by the customer.

<u>Typical equipment – Municipal Stations</u>

Typical equipment within municipal stations is similar to transmission stations, but are generally smaller in size because less capacity is required. In general, municipal stations include:

- Oil power transformers (ONAN/ONAF);
- Instrument transformers;
- Disconnect switches;
- Circuit Breakers;
- Cables;
- Fuses;
- Arresters.

2.4 Feeder Systems

Toronto Hydro employs feeder systems, or systems of power lines, transformers, switches and related equipment, to distribute electricity across the City of Toronto. The feeders are either installed on overhead poles (overhead systems) or travel through underground cables (underground systems). Overhead feeder systems can be located on the front side of a property (front lot) or at the back of the property (rear lot). However, rear lot systems will be phased out by the 2030s and are not considered in the scope of this study. They are progressively being replaced by front lot overhead or underground infrastructure, which provides Toronto Hydro more convenient access. In total, Toronto Hydro customers are served by over 900 feeders[9] (Navigant Consulting Ltd. 2011).

Approximately 30 % of Toronto Hydro's distribution network is comprised of 27.6 kV feeders from 3 - 4 km (considered ''short'' lines) to 5 - 6 km (considered ''long'' lines) in length. These systems are mostly located in the horseshoe area. 70 % of Toronto Hydro's distribution feeders operate at 13.8kV, and vary in length between 2 – 3 km (short) to 3 - 4 km (long) (Navigant Consulting Ltd., 2011). The 13.8 kV systems serve both the downtown and horseshoe areas. A very small percentage of feeders still operate at 4.16 kV.

2.4.1 Electrical Configurations

The electrical configuration of a feeder determines the way electricity is delivered to customers. It is indicative of the feeder's ability to provide electrical service in the event of equipment damage and electrical faults. There are many different electrical configurations of feeders, and they include radial, dual radial, open loop and closed loop systems. Some of these systems may also be nested within one another (e.g. an open loop system with downstream radial feeders). Toronto Hydro's main underground and overhead feeders are arranged in an open loop type configuration, although there are also dual radial and radial feeder systems, some of which may be nested within the open loop configuration. Only one feeder type, the 13.8 kV network, is arranged in a closed loop type configuration. The various electrical configurations considered in this study are:

- Underground dual radial and underground residential distribution (URD) feeders;
- Underground closed loop network feeders;
- Overhead open loop and radial feeders.

In the open loop system, the feeder line runs out of the station through two separate feeder arms that eventually reconnect outside the station to form a loop. A load interrupting switch (tie switch) is located at the reconnection point and is normally kept open between the two feeder arms. If one feeder arm goes out, the load can be fed by the other feeder arm by closing the tie switch. In open loop systems under single contingency condition[10], the customer typically experiences an interruption when the feeder is switched from one feeder arm to the other.

In radial systems, the customer is supplied by only one feeder. It is the least expensive design but also offers the least flexibility in electrical service restoration in the event of a fault, as there is no other feeder that can supply electricity until the line is repaired. Radial feeder segments may be nested within open loop systems.

Dual radial systems are similar in design to radial feeders except that each customer is connected to two parallel radial feeders. The load is supplied by one of the radial feeders, as the other radial feeder remains on standby. In the case of a fault, the load is transferred from one feeder to the other by manipulating interrupter switches tying the two radial feeders together. Large commercial and industrial customers, as well as Toronto Hydro municipal stations and several older Toronto Transit Commission (TTC) stations are typically served by dual radial systems. A compact loop system is similar in configuration to a dual radial system, but is employed where space is more limited (e.g. in existing vaults).

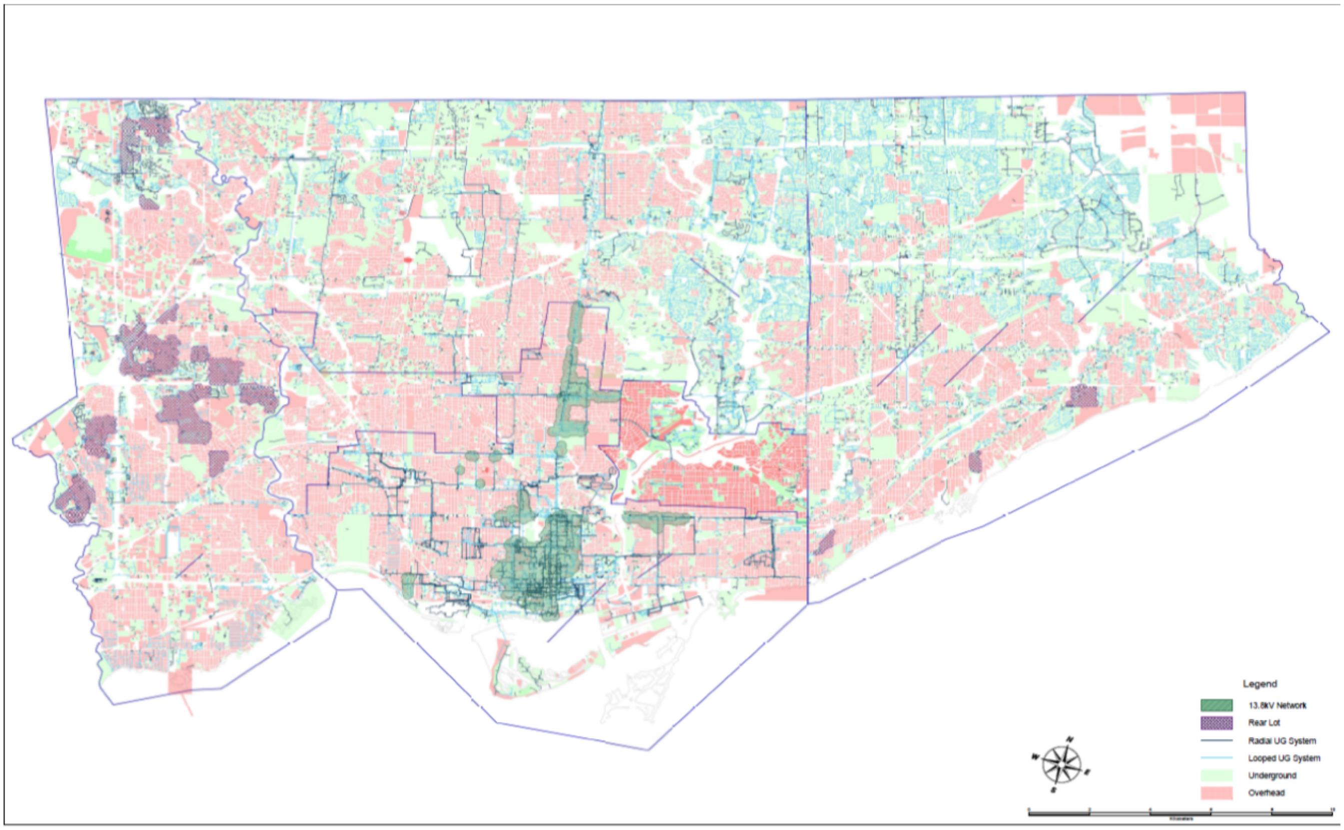
In closed loop systems, customers are supplied by multiple feeders, and are fed via several redundant transformers and network protectors. If one feeder goes out, the customer can be supplied by another feeder. Closed loop systems are advantageous because under single contingency conditions, customers experience no power interruptions (Toronto Hydro, 2007). Only Toronto Hydro's 13.8 kV network system is a closed loop system.

[9] This total may vary depending on how feeder branches and sub-branches are counted.

[10] Single contingency condition or N-1 represents the condition where all electrical equipment is in service except one element. For example, if a substation has two power transformers, but one of them is out of service, the condition is called "N-1". The condition "N-1" generally occurs after a major disturbance causes equipment to trip and go-offline.

Figure 2-7**Error! Reference source not found.** shows the distribution of feeder types across the city. The 13.8 kV network, represented in dark green, is mostly concentrated in downtown Toronto (downtown core and the Yonge Street and Bloor Street corridors), while the other feeder types can be found across the city.

Figure 2-7 Location of Feeders, by Type



Source: Toronto Hydro

<u>Typical equipment</u>

For all underground feeders

The distribution transformer station of underground feeder systems can be classified according to one of three types:

- Vault type: The vault transformer can be small and located just below ground for single phase clients, or large and deeper underground for clients requiring larger, three-phase power supplies. Some vault type transformers can be located above ground inside a building. The equipment located in vault type enclosures cannot operate if the vault is flooded.
- Submersible type: They are designed similarly to the vault type transformer stations but the equipment is designed to operate when submersed. For example, submersible transformers are capable of continuous unattended operation while completely submerged under a head of 3 m of water over the top of the tank (IEEE Std C57.12.24, 2009, p. 3). They are currently the preferred design due to their submersibility.
- Padmount type: The padmount transformer is located on ground level in a metal-clad enclosure.

Underground feeder equipment typically consists of the following:

- Cables: The cables used in underground systems are generally insulated with cross-linked polyethylene (XLPE) or a paper insulated lead cover (PILC). The PILC cables also contain oil
- Pilot wire: For large and sensitive customers

- Fault circuit indicators
- Power transformers modules:
  - Load-break switch modules: Metal enclosed, air insulated, Vacuum or SF6 arc extinction, motorized or manual;
  - Fuse modules: Metal enclosed, air insulated, electronic fuses or SF6 power fuses or current limiting fused;
  - Power transformer : Oil type (most), dry type (in above grade vaults) or some used FR3 fluid (environmental friendly);
  - Elbows: cable connections to power transformers.
- Specifically for the network system, typical equipment consists of the following:Primary feeders;
- Network Units;
  - Primary Switch – Embedded in power transformer;
  - N/W Transformer: dry type;
  - N/W Protector: Breaker, back-up fuse, relays, current transformers, cable limiter.
- LV secondary network grid or spot networks;
- Except for the old network protectors, all network unit equipment are submersible.

For overhead, open loop and radial feeders:

- Poles: See civil categories below;
- Distribution transformers : ONAN (Oil Natural Air Natural) system;
- Gang-operated switches, single-phase switches or SCADA switches;
- Load interrupting switches;
- Fuse disconnecting switches;
- Conductors: “tree proof” protected aluminium (AL) conductors, steel reinforced aluminium conductors (ACSR), aluminium conductors (no tree proof protection), and copper (CU, legacy);
- Voltage Regulators;
- Circuit-breakers with reclosers;
- Capacitors;
- Insulators: made from porcelain (approximately half of all installed insulators) and polymer material (porcelain insulators are being progressively replaced by polymer insulators).

2.5 Communications Systems

The communications systems support the control and protection of electrical equipment. They are divided between protection and control systems, and the SCADA system.

For power lines, the distribution switch automation is generally limited to the 27.6 kV systems (Toronto Hydro, 2007).

Protection and control systems

The protection and control systems are located inside control buildings. Except for batteries, they are located in a temperature controlled room. Batteries at some stations in the Former Toronto area are currently located in the basement of buildings. However, Toronto Hydro expects to relocate these battery assets above grade by the 2030’s in order to help reduce flooding threats.

Typical electrical equipment

- Relays:
- Fuse, Load-break Switch, Circuit Breaker;
- Batteries;
- Auxiliary systems: cranes, fire alarm systems, air compressors, etc.

SCADA system

The supervisory control and data acquisition (SCADA) system is an automated system to remotely control equipment and gather operating information about electrical equipment.

Typical electrical equipment

- SCADA Switch;
- Battery;
- The remote terminal unit (RTU);
- Fault Detector;
- Fiber optic conductor;
- Motorized cell interrupter.

2.6 Civil Structures

The civil structures house or provide structural support for all electrical equipment. They are found in transmission and municipal stations, and all underground and overhead feeder systems.

As a general rule of thumb, civil structures are generally older in the Former Toronto than in the horseshoe area. Older structures (before 1970) may be more susceptible to climate impacts due to their degradation (wood rotting, corrosion of steel) and lack of reinforcement in concrete and design loads.

Typical equipment

For transmission and municipal stations:

- Gantry Towers;
- Exit lines;
- Equipment supports;
- Building: for indoor stations.

For underground feeders and transformer stations:

- Reinforced concrete cable chambers;
- Concrete vaults;
- Underground cable ducts.

For overhead feeders:

- In 2014, there were approximately 176,000 poles in Toronto Hydro's electrical distribution system. The types of poles by construction material are approximately distributed as follows :
    - Concrete : 36%;
    - Aluminum: 2%;
    - Steel: 4%;
    - Cedar Poles : 58%;
    - Fiber glass: Negligible.
    - Iron: Negligible.
- Conductors and hardware (e.g. supports, bolts, etc.);
- Concrete footings (for steel, aluminium, concrete and some wood poles).

2.7 Auxiliary mechanical

Ventilation

All vaults have passive ventilation i.e. natural ventilation through slot openings in cover grates.

Drainage system

Toronto Hydro drainage systems can generally be divided according to the two types of vaults in which they are found:

- Small, shallow single phase sub vaults: do not contain pumps. These vaults' drains are connected to the city's sewer or storm sewer system and drain naturally. These vaults are also being fitted with automatic Petro plugs which stop drainage when oil is detected in the flow (equipment or other pollutant source) in order to prevent oil leaks into the sewer.
- Big deep vaults for Network, URD feeders: most of these kinds of vaults are equipped with mechanical pumps as they are located at a significant depth below grade and often below city sewers. Drains are installed in the walls of the vault and pumps are used to force water into the city's sewer systems. Approximately 10 % of network, URD vaults have drains without pumps (i.e. gravity driven natural drainage).

Sump pump

In 2014, approximately 1600 vaults out of 14,937 vaults had sump pumps (11%) (Toronto Hydro, 2014e). Toronto Hydro estimates that by the 2030's, these sumps will have oil sensing traps that will close if oil (equipment or other pollutant source) is detected.

2.8 Human Resources

Toronto Hydro has approximately 1,500 employees comprised of certified tradespeople, engineers and management professionals (Toronto Hydro, 2012). Employees who are involved in the operation of the electrical distribution system include supervisors and field crews for overhead, underground and network systems, control room staff, call centre workers and dispatchers. Toronto Hydro staff also includes the management team, engineers, asset management specialists and electrical system designers.

Weather can generally affect human resources in two ways. Adverse weather events can affect travel conditions on the journey to and from work for all employees. Furthermore, adverse weather events can affect the working conditions for field crews and field supervisors who need to access, operate or work on equipment across the city. Toronto Hydro strives to ensure a safe working environment for its employees, and has occupational health and safety policies and procedures in place that conform with the international occupational health and safety management system specification OHSAS 18001. These policies and procedures are complemented by the professional judgement of its workers as to whether conditions are safe enough to access outdoor equipment.

2.9 Time Horizon

The evaluation was carried out for the study period (2015 to 2050), but with specific focus on the possible state of the electrical system at the 2030's and 2050's time horizons. For example, this study considered changes to infrastructure systems based on current practices, trends and policy directions (e.g. transition from rear lot to front lot power lines, the partial phase out of 4.16 kV system, some demand and supply projections[11], replacement of

[11] It should be noted that city-wide land use changes (high rises, condo development and population growth) were not included in the analysis, due to the scope of such an undertaking and the complexity of information required. However, system vulnerability was judged based on climate change stresses, as it was assumed that gradual population growth would be accommodated by corresponding growth of Toronto Hydro systems under business as usual practices without the added stress of climate change.

non-submersible equipment). Toronto Hydro documentation, electrical standards and consultations with Toronto Hydro staff were all used to help identify and describe the potential changes to assets at the 2030's and 2050's time horizon. The probability of a climate parameter occurring during the study period and on an annual basis for the 2030's and 2050's was also determined (see next chapter for further details).

2.10 Other Potential Changes that May Affect Infrastructure

2.10.1 Dependencies on Hydro One Infrastructure

Toronto Hydro is part of an interdependent electrical system that is reliant on infrastructure facilities that generate electricity, transmission systems that transport electricity over long distance, and transformer stations that convert voltages for transport and use. The electrical generation and transmission supply infrastructure on which Toronto Hydro relies upon can also be vulnerable to the impacts of a changing climate, and are owned by other electrical companies and organizations in Ontario. Therefore, it is important to note that the vulnerability of Toronto Hydro is therefore also tied to the vulnerability of these supply side infrastructure.

It should also be noted that in the event of a power outage, certain facilities and dependent infrastructure can be supplied by temporary, backup power generators (such as diesel or natural gas generators). In some cases, homeowners may be equipped with photo-voltaic cells that may be able to provide some power in the event of an outage. However, these forms of dispersed generation are specific to facilities and individuals, and not sufficient to meet the demands of larger portions of the population. Dispersed generation does not currently provide sufficient capacity to alleviate Toronto Hydro of its dependence on the large scale electrical generation and transmission supply infrastructure.

Most of the 230 kV, 115 kV and 27.6 kV station equipment that tie Hydro One transmission infrastructure to Toronto Hydro are owned by Hydro One, except for the 27.6 kV breakers at the transmission stations supplying the former North York area and the Cavanagh transmission station, which is totally owned by Toronto Hydro. In general, Toronto Hydro owns the 13.8 kV switchgear equipment. Toronto Hydro and Hydro One share a common Transmission Connection Agreement (Toronto Hydro, 2007).

2.10.2 Load Projections

Electrical load or demand is a significant factor in the operation of transmission stations. Demand is influenced by a variety of factors, including population size, types of uses (e.g. residential, commercial, industrial, institutional, infrastructure), time of day (e.g. peak, off-peak, night time), as well as daily temperature (e.g. heating, cooling).

For the present study, the projections of electrical load on each of the main transmission stations serving the City of Toronto were completed, and are shown in the next table. The methodology used by Toronto Hydro to calculate the projected load for the 2030's and 2050's is described in **Appendix F**. Major future load demand, added transmission station added capacity (i.e. growth), and proposed load transfers[12] were considered by Toronto Hydro.

[12] Load transfer represents the capability to discharge some load from one station to another transmission station. In case of an outage or a very high demand, the loss of supply, or requirement for additional electricity can be provided by another location. Some transmission stations have higher transfer capabilities than others due to higher installed capacity and/or lower demand. However, this capability changes with time: the increasing demand can lessen this flexibility, while investments in new additional capacity can increase the station capability.

Table 2-2 Load Projections by Transmission Station

Service Area *(Voltage step down)*	Number of Stations	Projected load (2030's)[13]	Projected load (2050's)
Former Toronto			
Downtown core *(115 kV/13.8 kV)*	6	86-95%	>95%
Downtown outer *(115/13.8 kV, 230/115 kV,115/27.6 kV)*	2	70-85%	>95%
	6	86-95%	
	3	>95%	
Horseshoe			
North Stations *(230/27.6 kV)*	1	86-95%	>100%
	1		86-95%
East *(230 kV/27.6 kV, 230/115 kV)*	1	<70%	70-85%
	2	<70%	86-95%
	3	70-85%	86-95%
	2	86-95%	86-95%
	1	86-95%	>100%
	1	>100%	>100%
Northwest *(230 kV/27.6 kV)*	2	70-85%	>100%
	1	86-95%	86-95%
	1	<70%	86-95%
Southwest *(230/27.6 kV,230/115 kV)*	2	86-95%	>100%

2.11 Data Sufficiency

The general characteristics of the systems under review were adequate for the purpose of this exercise, although it should be noted that no site visit was conducted in the project. Chapter 7 contains recommendations about further work that can be used to enhance the analysis of electrical system performance and sensitivities to climate related stresses.

[13] Note that Toronto Hydro considers 95 % as the max station load capacity in former Toronto area. This is because there are no station ties between station service areas to allow for the transfer of some feeder loads from one station to another. When a former Toronto area station achieves 95% of its capacity, it signals to Toronto Hydro that a station load relief project is required. In the horseshoe area, station max capacity is considered to be 100% max load capacity, as there are existing station ties available to allow the transfer of feeder loads from one station to another.

3 Assessment of Climate Changes

This chapter describes how the climate data used in this study was developed. This work involved three activities, the identification of climate parameters, the estimation of the historical and future probability of occurrence of climate parameters, and the conversion of probabilities into PIEVC scoring to support the risk assessment. The results of this work are summarized in a table at the end of this chapter (Table 3-2). **Appendix B** and **C** support this chapter, providing additional background information on the methods, information sources and assumptions. The climate work was principally conducted by Risk Sciences International in collaboration with AECOM.

3.1 Climate Data Development Methodology

The development of climate data to support this study involved three main activities.

- First, climate parameters (e.g. temperature, precipitation, wind) and threshold values at which infrastructure performance would be affected were identified (i.e. climate parameters);
- Next, the probability of occurrence of each climate parameter was estimated for future climates; and,
- Finally, the probability information of climate parameters was converted into the PIEVC seven point scoring scale to support the risk assessment.

3.1.1 Identification of Climate Parameters

The identification of relevant climate parameters and infrastructure impact thresholds was an iterative process involving a combination of three methods:

- Literature review of design loads in codes, standards and published literature;
- Practitioner consultation, including targeted interviews, email communications, and workshops; and,
- Forensic analyses of either system specific case studies or relevant cases in the published and grey literature.

While these methods were employed during Phase I, they were expanded significantly and updated for Phase 2. The list of climate parameters from Phase 1 of this study was revisited through practitioner consultations (i.e. workshops), and a more thorough forensic analysis process was conducted using newly available impacts data provided by Toronto Hydro. Literature, including the Institute of Electrical and Electronics Engineers (IEEE) and CSA standards, was reviewed by both RSI and AECOM research team members, yielding more specific design thresholds and criteria. Further information about these techniques can be found in **Appendix B.**

3.1.2 Estimating the Probability of Occurrence of Climate Parameters

To estimate the probability of occurrence of climate parameters over the study period, their probability of occurrence was first established for historical climates. Future conditions cannot be well understood until current and historical climate conditions are quantified, particularly with regards to already existing vulnerabilities and thresholds present within the distribution system. This historical information was combined with climate projections from an ensemble of global climate models through the application of the “Delta-method” (see description on next page) to obtain estimates of the probability of occurrence for climate parameters. Additional complementary estimation techniques (i.e. regional climate models, statistical downscaling, climate analogues) were also employed to evaluate several complex climate events (e.g. freezing rain, ice storms, high intensity rainfall, lightning, tornadoes), as well as to validate or refine the results obtained from the “Delta-method” approach. These tasks are summarized in the following section while more details can be found in **Appendix B**.

Establishing Historical Climate Baseline

The probability of occurrence of climate parameters under historical climate conditions was established in Phase I of this study. Phase 2 reviewed and further refined them in order to serve as a baseline for climate change projections.

Historical climate conditions were established based on Environment Canada's climate station network, the most reliable and highest quality long-term climate record in Canada. While there are numerous climate stations in and around the City of Toronto, detailed hourly weather data are usually only available from airport locations. Thus, the majority of historical climate information used in this analysis is based on records from Pearson International Airport, with further contributions from Buttonville and Toronto Island Airports. Toronto is also the location of the climate station with the longest period of record in Canada, located at its City Centre location, a separate site which provided further perspective on longer term historical climate.

In the case of extreme, very localized, or complex climate events (e.g. tornadoes, freezing rain, ice storms, lightning storms), authors employed alternative methods (e.g. using averaging periods greater than 30 years) or consulted alternative data sets (e.g. the historical tornado database) to establish a historical baseline because this information was not directly available from weather station data.

Future Projections

The climate projection data which serves as a basis for this study was sourced principally from global climate models (GCMs). The latest International Panel on Climate Change (IPCC) 5th Assessment Report (AR5) provided results from 40 GCMs, produced and operated by modeling centres from around the globe. These models provide many of the basic parameters used in developing projections, as well as providing the "boundary conditions" for more detailed assessments, such as downscaling studies. The availability of multiple models also allows for the use of climate model "ensembles," which use multiple models for the development of projections, rather than employing the results of a single model which may contain biases affecting the accuracy of results. The use of ensembles is considered by the IPCC as a best practice for climate analyses, and therefore has been the dominant method used for climate projections in Phase 2.

GCMs require "emissions scenarios" as inputs for the calculation of climate projections. The latest IPCC AR5 has introduced a new method of describing future changes in emissions. Representative Concentration Pathways, or RCPs, describe explicitly the expected increase in energy generated by increases in greenhouse gases. The most pessimistic emissions scenario, RCP 8.5, indicates an increase of 8.5 watts per square meter of additional energy under future climate conditions. It is referred to as the "business as usual" emissions scenario, provides the best fit based on historical trends in global emissions, and was the scenario used for Phase 2. Further details on IPCC findings, GCMs, RCPs, and other aspects of climate change projections, can be found in **Appendix B.**

Applying the "Delta-Method"

Individual GCMs contain inherent biases when attempting to recreate historical climate, for example being either too cool or warm compared to historical averages. To compensate for this effect, the "Delta-method" was employed. First, GCMs were evaluated to determine changes from their own respective baselines. This difference between model baseline and projected conditions is then applied to the observed historical climate baseline. For example, if the GCM ensemble indicated an average increase of 2 degrees between the baseline period and the 2050's, and a given station shows an average annual temperature of 3°C, then the projected annual average temperature for that location for the 2050's becomes 5°C. This represents the "delta", or the change in climate parameter based on the difference projected by the GCM ensemble applied to historical baseline data.

Treatment of Complex Climate Events

To validate the results obtained from the GCM – "Delta-Method" for some of the climate parameters, three other complementary estimation techniques were also used, regional climate modeling, statistical downscaling techniques and climate analogues. Furthermore, some complex climate events tend to occur on much smaller spatial and temporal scales than are covered by GCMs (e.g. tornadoes, freezing rain, ice storms, lightning). Use of these three complementary estimation techniques was necessary to develop projections for these kinds of climate parameters.

It should be noted, however, that even with the availability of specialized methods, there remain highly localized atmospheric events which cannot be projected with confidence, and the effects of climate change on these types of events are still being researched by the climate research community. See **Appendix B** for further discussion of developing projections for complex climate events.

Estimating the Probability of Occurrence of Climate parameters

The methodology used for determining climate parameter probabilities for Phase 2 was somewhat modified from standard PIEVC Protocol based studies. The Protocol (Engineers Canada, 2012) indicates that the probability of a climate parameter occurring should be based on the probability of occurrence during the *full* time period of the study, which is typically the life cycle and long-term planning considerations of the infrastructure under study. For Phase 2, a period of 35 years between 2015 and 2050 was chosen. However, in recognition that response to these hazards can include both asset hardening/replacement cycles (long-term measures) as well as maintenance and management considerations (short term measures), a second set of probabilities based on annual occurrence was also determined. Examining both annual and study period probabilities was useful for understanding vulnerabilities based on climate parameters that would occur on an annual basis (e.g. high temperature) against those which would occur less than annually, but with the potential to cause significant impacts sometime during the 35 year study period (e.g. ice storms, high winds, tornadoes).

Annual probabilities are expressed as the number of occurrences per year for historical and (where available) projected estimates for the 2030's and 2050's, or more specifically for 30 year periods centred on those future decades. The so-called "study period" or "lifecycle" probability of occurrence is then expressed as a percentage (i.e. given those annual frequencies, what is the overall probability that an event will occur during the *entire 35 year time horizon*?).

The probability of occurrence of a climate parameter considered in this project is, in most cases, representative of a "point" probability (i.e. historical probability values based on measurements at a single location). However, the lightning and tornado climate parameters were also evaluated using different "target" sizes to illustrate the effects of changing this perspective, as well as to better correspond with field conditions and associated response. More detailed information about how the probabilities of individual climate parameters were determined can be found in **Appendix B**. The results of this work are listed in Table 3-2 at the end of this chapter.

3.1.3 Assigning a PIEVC Score to Climate parameter Probabilities

The probability of occurrence for climate parameters both annual and during the study period were converted into PIEVC probability scores (i.e. 0-7) for the risk assessment, following the quantitative "Method B" approach indicated in the Protocol (Engineers Canada, 2012) (see Table 3-1). For example, the annual probability of occurrence of high temperatures above 40°C was estimated to occur approximately 0.01 times per year in the historical period (last 100 years), or 1 % probability of occurring each year (PIEVC score 1). Similarly the annual probability for this parameter was 0.3 to 2 times per year for the 2030s, which signifies a 30 % to >100 % probability of occurring each year (PIEVC scores 4 to 7 respectively). This climate parameter is estimated to occur between 1 to 7 days per year by the 2050s, such the annual probability of occurrence is >100% (PIEVC score 7).

Table 3-1 PIEVC Version 10 Probability Scores based on Method B

Score	Probability	
0	< 0.1 %	< 1 in 1,000
1	1 %	1 in 100
2	5 %	1 in 20
3	10 %	1 in 10
4	20 %	1 in 5
5	40 %	1 in 2.5
6	70 %	1 in 1.4
7	> 99 %	> 1 in 1.01

3.2 Summary of Results

24 climate parameters covering temperature, precipitation, wind and lightning hazards were considered within the climate analysis. However, four of them were not carried forward in the vulnerability assessment due to data availability issues or relevance[14]. Table 3-2 provides a summary of the climate data results. Relevant climate parameters and infrastructure thresholds (climate parameters) to be used in this study are listed. For these climate parameters, historical and future probabilities of occurrence, as well as PIEVC probability scores for annual and study period probabilities are presented.

Table 3-2 Climate Parameters and Thresholds, Occurrence Probabilities and PIEVC Scoring

Climate Parameter	Threshold	Annual Probability (Historical; **Projected 2030 and *2050***)	Probability of Occurrence Study Period (2015-2050)	PIEVC Scoring		
				Historical	2030's & 2050's	Study Period
Daily Maximum Temperatures	25°C	66 per year; **84 per year**, ***106 per year***	100%	7	7	7
	30°C	16 per year; **26 per year**, ***47 per year***	100%	7	7	7
	35°C	0.75 per year; **3 per year**, ***8 per year***	100%	6	7	7
	40°C	~0.01 per year[15]; **0.3 to 2 days per year**, ***1-7 days per year***	~100%	1	4 - 7	7
High Daily Avg Temperature	30°C	0.07 per year[16]; **N/A**, ***1.2 days per year***	~100%	3	7	7
	35°C	*Zero* occurrences historically; ***zero occurrences projected***	0%	0	0	0
Heat Wave	3 days max temp over 30°C	0.88 per year; **>1 for both**	100%	6	7	7
High Night time Temperatures	Nighttime low ≥23°C	0.70 per year; **7 per year**, ***16 per year***	~100%	6	7	7
Extreme Rainfall	100 mm in <1 day + antecedent	0.04 per year; ***extreme precipitation expected* ↑, *percentage unknown***	~75%-85%	2	3	6

[14] The climate parameters not evaluated in the vulnerability assessment were high daily average temperature above 35°C (relevance), 6 hr+ freezing rain (relevance, as no ice accretion threshold was known), Minor ice accretion and deicing agents (complex interaction, no projection data available) and tree growth, pest and disease (complex interaction, no data available).
[15] Based on data from Toronto City Center station rather than Pearson Airport.
[16] Based on 4 occurrences since 1961 at Pearson Airport; see discussion in text for further details.

Climate Parameter	Threshold	Annual Probability (Historical; **Projected 2030 and *2050***)	Probability of Occurrence Study Period (2015-2050)	PIEVC Scoring		
				Historical	2030's & 2050's	Study Period
Ice Storm/Freezing Rain	15 mm (tree branches)	0.11 per year; **>0.13 per year, *>0.16 per year***	>99%	3	3	7
	25 mm ≈ 12.5 mm radial	0.06 days per year; **>0.07 per year, *>0.09 per year***	>95%	2	3	7
	60 mm ≈ 30 mm radial	High Risk: 0.007 events per year; **>0.008 per year; *>0.01 per year*** Low Risk: 0.002 events per year; **> 0.0023 per year; *0.003 per year***	High: ~25% Low: ~8%	0-1	0-1	2-4
	6 hours + freezing rain	0.65 days per year; **~0.75 per year, ~*0.94 per year***	100%	5	6	7
High Winds	70 km/h+ (tree branches)	21 days per year; **N/A, *24 to 26 per year***	100%	7	7	7
	90 km/h	2 days per year; **N/A, *>2.5 per year***	100%	7	7	7
	120 km/h	~0.05 days per year; ***likely ↑, but % unknown***	~85% or higher	2	2	7
Tornado	EF1+	1-in-6,000; ***Unknown, no consensus***	~0.6%	0	0	1
	EF2+	1-in-12,000; ***Unknown, no consensus***	~0.3%	0	0	0
Lightning[17]	Flash density per km km^2	1.12 to 2.24 per year per km^2; ***Expected increase, % change unknown***	~50-70%(Lg); ~10-20% (Sm)	Lg - 2 Sm - 0	n/a	Lg – 6 Sm - 3
Snowfall	Days w/ >10 cm	1.5 days per year; ***Trend decreasing but highly variable***	100%	7	7	7
	Days w/ > 5cm	5 days per year; ***Trend decreasing but highly variable***	100%	7	7	7
Frost		229 frost free days; **249 frost free days, *273 frost free days***	100%	7	7	7
Complex Interactions	Minor ice accretion + deicing agents	***Projections unavailable***	N/A		N/A	
Complex Interactions	Changes in tree growth, disease conditions	***Projections unavailable***	N/A		N/A	

3.3 Data Sufficiency and Recommendations

The primary sources of information used in this climate data work were:

- Environment Canada Weather Station Data;
- IPCC AR5 quality controlled GCM output;
- TRCA environmental data and observations (TRCA 2014).

The climate data available for this study was judged to be sufficient to cover the majority of climate related stresses to electrical distribution systems (stemming from temperature, precipitation and wind). The study area of the City of Toronto also benefited from having good quality, long-term climate data that covered most areas of the city for these types of climate parameters. While further studies, in-depth analyses, and data quality improvements can be made (see Chapter 7), the climate data that was available was sufficient to support the risk assessment.

[17] Note that "Lg" and "Sm" refer to large and small transformer stations, see Appendix B for more details.

4 Vulnerability Assessment Methodology

The vulnerability of the electrical system to climate parameters was initially completed by employing a screening level risk based methodology (risk assessment) to identify low, medium and high risk interactions. The level of risk was evaluated based on the probability of occurrence of a climate parameter coupled with the severity (consequence) of the impact on the system and on electrical service provision. Low risk level interactions were generally judged as not being a significant issue for Toronto Hydro. Medium level risks were evaluated through a further engineering analysis to determine whether the interaction resulted in vulnerabilities (or part of a general pattern of vulnerability). Finally high risk level interactions were deemed as vulnerabilities for Toronto Hydro.

The general procedure for the risk assessment is described in Step 3 of the Protocol. However, study specific considerations (e.g. the *systems level approach*), adaptations and guidance for completing the risk assessment are described in the following chapter. Completion of the risk assessment follows the "Consultant Option" of the Protocol[18]. Notably in this option, AECOM completed the risk matrix through internal meetings with its own electrical engineers. This information was then validated with Toronto Hydro staff in a workshop held on October 10, 2014, at Toronto Hydro's offices.

4.1 Risk Tolerance Thresholds

The risk tolerance thresholds employed within this analysis conform with the proposed thresholds of the Protocol as given in the table below. These thresholds were validated with Toronto Hydro at the workshop.

Table 4-1 Risk Tolerance Thresholds

Risk Range	Threshold	Response
< 12	Low Risk	Monitoring or no further action necessary
12 – 36	Medium Risk	Vulnerability may be present. Action may be required, TBD through engineering analysis
> 36	High Risk	Vulnerability present, action required

4.2 Yes/No Analysis

The first consideration of the risk assessment is to identify whether a climate parameter will interact with the infrastructure system under consideration. A Yes/No analysis column for each of the 20 climate parameters is included in the risk assessment matrix presented in **Appendix D**. A "No (N)" result means that there is no interaction between the climate parameter and infrastructure system, while a "Yes (Y)" result means that there may be an interaction. The severity assessment is conducted only for "Yes" interactions.

4.3 Infrastructure Performance Responses - Systems Level Approach

As mentioned in the introduction, this study adopts a *systems level approach* to the analysis of climate change impacts on Toronto Hydro electrical distribution infrastructure due to the extensive, complex and interdependent nature of the electrical system. The severity of impact is evaluated based on the consequences of the interaction of different weather events with the systems and subsystems under study.

The relevant infrastructure performance responses remain the same as presented in the pilot case study. Notably, they are:

- Structural design - *Structural integrity, cracking, deformation, foundation anchoring, etc.*

[18] This approach, rather than the facilitated option, was adopted in this study because it was more efficient; the learnings gained from the pilot case study provided AECOM with the necessary insight to complete the risk assessment on its own prior to validation with Toronto Hydro.

- Functionality - *Effective load capacity, efficiency, etc.*
- Serviceability - *Ability to conduct maintenance or refurbishment, etc.*
- Operations, maintenance and materials performance - *Occupational safety, worksite access, operations and maintenance practices (frequency and type), etc.*
- Emergency Response - *Planning, access, response time*
- Insurance Considerations (Toronto Hydro perspective) - *claimable for repair, cause 3rd party payment, affect insurance rates*
- Policy and Procedure Considerations - *Planning, public sector, operations, maintenance policies and procedures, etc.*
- Health and Safety - *Injury, death, health and safety of Toronto Hydro employees, the public, etc.*
- Social Effects - *Use and enjoyment, access, commerce, damage to community assets (buildings), public perception, etc.*
- Environmental Effects - *Release or harm to natural systems (air, water, ground, flora, fauna)*

It is clear that within a *systems level approach*, weather interactions with infrastructure systems can solicit a range of different performance responses, as well as responses of differing degrees (i.e. intensity) from different components. In other words, some components within a system are more sensitive to certain types of weather events than others (e.g. heat affects the operation of transformers more than it affects the wooden pole on which the transformer is attached).

In order to conduct a logical, structured analysis, the proposed *systems level approach* identifies the infrastructure performance response stemming from the component (e.g. pole, transformer, power line, switch, etc.) which constitutes the weakest link in the system category for a given weather parameter. The component whose functionality, capacity, structural integrity or operation is affected or compromised the most, which in turn may cause other interdependent components or the entire system to cease to operate, fail, or lose capacity, constitutes the weakest link in the system. For example, the failure of a station power transformer due to high temperature and load may cut off electricity service, irrespective of what the heat may do to other equipment and structures. The station power transformer is thus considered to be the most sensitive and weakest link under high heat conditions.

As the primary role of Toronto Hydro’s electrical distribution infrastructure is to provide electricity, one primary guiding criteria was used to determine which component(s) within the major systems categories constituted its weakest link: the component which, due to an interaction with a weather event, resulted in damage/failure of that component, which in turn compromised the ability of the system to deliver electricity to customers safely and securely. The risk assessment matrix presented in **Appendix D** contains a column named “consequence” which identifies the weakest link component and the anticipated infrastructure performance response.

4.3.1 Consideration of Redundancy and Station Capacity

While a component malfunction or failure may compromise the system’s ability to provide electricity safely and securely, a *systems level approach* allows system design characteristics to mitigate this impact. Two notable characteristics of electrical systems are considered by this study: redundancy and station capacity.

Redundancy is the duplication of equipment and systems that afford an alternative way to deliver electrical services in the event of equipment damage or failure. In electrical systems, redundancy is provided through the presence of similar or identical equipment operating in parallel or kept on standby, and is a key component of essential infrastructure services such as electricity provision. Station capacity indicates that a station possesses capacity in excess of normal demand (i.e. under normal circumstances).

Redundancy and station capacity are characteristic of the different types of electrical systems under study. As redundancy and station capacity can mitigate component failures (i.e. allow systems to continue to provide electricity despite equipment failure in one area), they are used as mitigating factors which can attenuate severity scores. The explanation of how redundancy and station capacity are evaluated for each of the major systems categories is in presented in the sections below.

Transmission Stations

A station's ability to mitigate the system's vulnerability to climate is most usefully considered with respect to high temperatures. During high temperatures, stations with greater excess capacity will be able to continue to supply electricity despite increased demand, while stations with less excess capacity may have to reduce demand (e.g. shed load through temporary forced outages) in order to operate station equipment acceptably (e.g. to avoid overheat and burnout).

Transmission station capacity is based on the load projection exercise completed by Toronto Hydro for this project. This study is briefly described in **Appendix F (**Also see Chapter 2, *Load projections*, for more information)*.* Station capacity is rated as low or good based on the load cut-offs shown in the table below. If the station capacity is rated as low by the end of the study period (2050's), its severity evaluation for high temperature parameters is increased by ''+1''.

It is possible that excess station capacity can also be considered as a mitigating factor in the event of freezing rain, flooding, high winds, etc. For example, if a high wind event causes flying debris to damage an outdoor station, an adjacent station can help by picking up some of the load. In this case, it is the capacity of adjacent stations which helps determine the vulnerability of a service area. In the horseshoe area, station and feeder ties between service areas allow some of the load to be transferred[19]. However, this factor is not considered in the present study because adjacent stations can only take on a small portion of a faulted station's load (i.e. no station is designed to take the full load of an adjacent station, otherwise it would be overdesigned), nor are there sufficient feeder or station ties to allow the complete transfer of the load. Thus, large portions of a service area may still be susceptible to an outage at its transmission station in spite of the fact that an adjacent station has excess capacity.

Table 4-2 Severity Rating Based on Station Capacity by the 2050's

Severity Rating	Station Projected Load by the 2050's
Low (+1)	≥ 95 % (Toronto) and ≥100% Horseshoe Area
Good (no change)	< 95 %

Municipal Stations

The redundancy of the municipal stations is based on geography, and only considered for high temperature parameters for the same reasons as listed above under transmission stations. According to Toronto Hydro, if a municipal station is located in the Former Toronto area, it is generally considered that the station has less transfer capability than a station located in the horseshoe area. Severity ratings for all municipal stations in the Former Toronto area are increased by ''+1'' to reflect the low station transfer capacity in the event of a problem. This severity increase for former Toronto area municipal stations does not apply to other climate events such as freezing rain or wind because these stations are generally located indoors in the Former Toronto area.

The Toronto Hydro to Private ownership stations are dedicated to the owner. There are no transfer capacities to another station. A ''+1'' is added to the severity rating for high temperature parameters.

[19] Recall that at present, there are no station ties between station service areas in the Former Toronto area. The addition of station ties in this area is constrained by the fact that infrastructure is older, located in a dense built urban environment, and generally underground. At present, Toronto Hydro is considering the addition of station ties in the Former Toronto area, but this is not considered in this risk assessment due to its preliminary nature of this idea. In the horseshoe area, station ties allow stations to provide some load relief to adjacent service areas when required.

Underground Feeders

The redundancy of the underground feeders is based on the configuration of the feeder and its location in the city. Dual radial and residential feeders in the Former Toronto area are considered to have the lowest redundancy and capacity because structures are older, more stressed by higher loads, and are installed with less space between the conductors. The arrangement of the conductors is important because the ampacity of conductors are sensitive to the heat generated by nearby conductors. Severity ratings for these feeders are increased by ‘’+1’’ as a result (Table 4-3).

Table 4-3 Severity Rating Based on Feeder Configuration

Severity Rating	Increasing Levels of Feeder Redundancy
Low (+1)	Dual Radial & URD : Former Toronto
Moderate (no change)	Dual Radial & URD : Horseshoe
Good (no change)	Compact Loop Design
Best (no change)	Network

Overhead Feeders

The redundancy of the overhead feeders is considered between two configurations: radial or loop. Radial lines cannot be backed-up in the event of a fault, while loop configurations could allow electricity to be brought in through the “other side” of the loop. For this purpose, the severity ratings for radial feeder configurations are increased by ‘’+1’’.

Communications Systems

The redundancy evaluation is not considered for the communications systems, as they do not mitigate circumstances of loss of electrical service provision.

Civil Structures

Historically, infrastructure built for the distribution of electricity in the City of Toronto were concentrated in the downtown core and inner city and later extended to the horseshoe area. Part of the electrical equipment was replaced over time but much of the civil structures (e.g. underground vaults) remain in place due to their expected lifespan (35 - 60 years). It is thus assumed that the civil structures in the Former Toronto area are older and more degraded than the structures in the Horseshoe Area. A ‘’+1’’ severity scoring is added to the Former Toronto civil structures.

4.4 Scoring Severity

The severity scoring exercise is conducted using the scoring scale defined by the Protocol, method D. Examples of impacts on different equipment were developed in the course of this analysis. In addition to the guidance provided by the Protocol on severity scoring, this study provides a further, electrical system specific consideration in severity scoring. Two complementary, severity scoring scales were developed for this study to reflect the severity scoring differences between stations and feeder systems. As stations represent major nodes in the distribution of electricity, an affected or disabled station could result in a loss of service on all downstream feeder systems and customers. However, if a feeder branch or sub-branch is affected, only the customers on the branch or sub-branch may be affected. Thus, the impacts on station equipment are judged to be more severe than impacts on feeder systems. The severity scoring scale employed in this study, as presented below, reflects this general consideration.

Table 4-4 Severity Scoring Scale for Electrical Distribution Systems

Score	Stations			Feeders	
	Method D	**Descriptive**	**Examples**	**Descriptive**	**Example**
0	No Effect	Negligible or N/A		Negligible or N/A	
1	Measurable	Very Low - Some measurable change		Some loss of serviceability & capacity, no loss of function	*Arrestor failure, overheating cables, salt deterioration of civil/electrical equipment*
2	Minor	Low - Slight loss of serviceability	*Station battery – lifespan shortened*	Some loss of capacity & function	*Overheating transformer from high load*
3	Moderate	Moderate loss of serviceability, some loss of capacity, but no loss of function	*Station transformer heating up, but possibility of meeting demand from another station*	Moderate loss of function	*Broken spring in underground switchgear, distribution transformer out (must replace), cable*
4	Major	Major loss of serviceability, some loss of capacity & function	*Station transformer heating up, need to do load shedding*	Major loss of function of multiple equipment – localized	*Transformer and switchgear out (replace multiple equipment)*
5	Serious	More loss of capacity & function	*Station transformer heating up, need to do load shedding for longer duration*	Major loss of function of multiple equipment – wide area	*Transformer and Switchgear out Flooded vault that cannot be pumped*
6	Hazardous	Major - Loss of Function	*Loss of CT/VT transformer, battery assets*	Major loss of function of multiple equipment – wide area	*Leaning pole/downed line*
7	Catastrophic	Extreme – Loss of Asset	*Station trans. failure*	Major loss of function of multiple equipment – wide area	*Downed pole, line and transformer*

4.5 Mapping Risks

Due to the sheer number of similar assets and their distribution across the city, study authors and Toronto Hydro have elected to map climate change risks to the electrical distribution system in the City of Toronto. It was decided that two main asset classes would be included in the risk map: stations and feeders. The risks to supporting infrastructure, such as communication systems and civil structures, were difficult to represent on such a large scale. Furthermore, the risks to these systems are generally associated with, and can be adequately illustrated by, the risks to the stations and feeder systems.

The risk mapping exercise was completed using the geographic information systems (GIS) resources provided by Toronto Hydro. AECOM provided the final risk assessment matrix results to Toronto Hydro's GIS team. Each of the station and feeder assets in the risk assessment matrix were identified on GIS maps. Stations were illustrated as polygons representing the stations' service areas rather than as points where stations are located. This was done in order to illustrate the fact that faults at a station can affect an entire service area. Feeder systems were illustrated as line vectors on the map. Next, the low, medium or high classification of station or feeder risks were represented by colouring the assets class representations (polygons or lines) in yellow, orange or red to denote low, medium and high risks respectively. Where there were no interactions between climate and infrastructure, asset representations were coloured in grey. Finally, white spaces within the City of Toronto generally indicate where no electrical service is provided. Results of the risk mapping exercise are presented in Chapter 5 and in **Appendix E**.

5 Assessment Results

This chapter presents a summary of anticipated impacts from the interaction of climate events with electrical distribution system infrastructure resulting in low, medium and high risk interactions. In addition, special case risks are also presented.

5.1 Low Risk Interactions

High Temperature

SCADA systems may be affected by ambient air temperatures above 40°C. According to equipment design specifications (S&C manufacturer, 2011), such temperatures constitute unusual conditions for the interrupters within the SCADA system. At high temperatures over 40°C, the accuracy of power line current and voltage sensors, as well as the ability to provide DC voltages for the control of the switch, are not assured. SCADA system equipment are tested to operate between -40°C to +40°C. However, other components of the SCADA system like the communication and control unit can operate at temperatures up to +70°C. A low risk score was given considering that the SCADA switch is able to operate in temperatures above 40°C, but its performance (accuracy of sensors) may decrease.

Extreme Rainfall

Extreme rainfall poses a low risk to certain underground feeder systems in the horseshoe area. Underground feeder systems with some equipment located in above ground vaults or on padmounts may be affected by localized flooding due to extremely rainfall. This creates an issue in terms of accessing equipment.

Some transmission stations in the Former Toronto area currently have batteries and switchgear located below grade. This equipment could be damaged if flooding occurred. Toronto Hydro is currently moving its battery assets above grade when they reach the end of their lifecycle (typically 10 – 12 years). By the 2030's, it is expected that all station batteries will be moved above grade. Some of the switchgear equipment will also be moved above grade, although stations in the Former Toronto area may face space constraints to moving all equipment above grade. As such, it is likely that some switchgear will still be located below grade by the 2030s. However, stations are equipped with multiple sump pumps which can evacuate water that flows into the basements. According to a Toronto Hydro representative, there have been no flooding incidents to Toronto Hydro stations owing to heavy precipitation over the last several decades due to the pump and drainage systems found in stations. Based on expected work to relocate batteries and certain switchgear, and continued adequacy of sump pumps, the risk of flooding from extreme rainfall for transmission stations in the Former Toronto area was rated as a low risk.

Freezing Rain

For stations, 15 mm or less of freezing rain are not expected to create sufficient ice loads to cause structural problems. Freezing rain could cause some delays in accessing equipment (e.g. ground or equipment encrusted with a layer of ice), although this was judged to be of low risk by workshop participants

Snow

Snow accumulation and snow fall, especially for days with >10 cm of snow, can also cause visibility and access issues. Access to padmounted transformers and switches, as well as underground vaults may be hampered by snow pushed aside from road and sidewalk snow clearing equipment, thereby lengthening the time needed to access equipment. However, access issues from snow were judged to be of low risk by workshop participants.

Frost

Frost may cause the displacement of the ground (frost heave) and compromise the stability of the foundations of poles, vaults and cable chambers. Frost heave events are generally localized, and do not tend to disrupt electrical service. Furthermore, the number of frost free days are expected to increase by 2050 due to increases in annual temperatures. For these reasons, frost was judged to be of low risk. Civil structures located in the former Toronto area were given a slightly higher (+1) severity rating (and therefore risk rating) because the infrastructure is generally older than those found in the horseshoe area.

5.2 Medium Risk Interactions

High Temperature

High ambient air temperatures starting at 25°C and above are responsible for the majority of medium risks evaluated within this study. Unless stated, the temperatures presented below exclude consideration of humidity on felt temperature (i.e. humidex). From an electrical equipment point of view, it is the ambient air temperature, not humidity, which impacts the structural integrity or lifespan of equipment. Humidity, coupled with high ambient air temperatures may result in higher felt temperatures by people, which in turn can increase the demand for air-conditioning. However, risks posed by high temperatures to infrastructure are evaluated in terms of their design and performance characteristics (ability to shed heat or cool down), which are not affected by humidity levels. High humidity was considered when evaluating the risks to Toronto Hydro personnel.

High temperatures affect the lifespan of station batteries. Where the air temperature of rooms that house station batteries exceeds 25°C, the lifespan of the batteries will begin to degrade. This will result in the long-term in the replacement of batteries sooner than expected. The buildings containing the rooms where batteries are stored afford some protection from changes to external air temperatures. This means that an external air temperature of 25°C may not immediately trigger the premature degradation of batteries. However, rooms where batteries are stored are not temperature regulated, and the impacts to battery lifespan will increase as external air temperatures increase above 25°C. Heat impacts on station battery lifespan were judged to be of medium risk.

As maximum daily air temperatures exceed 35°C, station power transformers will be the most critical pieces of equipment to be affected. First, the use of air-conditioning will increase, thereby increasing the electrical load on transformers. Transformers will heat up, but warm ambient air temperatures also reduce the effectiveness of natural or mechanical cooling. Stations with low projected excess capacities by the 2030's and 2050's will be less able to meet additional demand during periods of high temperature because of higher existing base load. These include transmission stations located in downtown areas, as well as Bathurst station, Sheppard, Leaside, Rexdale, Woodbridge, Manby and Horner. These were judged to be slightly more at risk (+1 severity) as compared to other stations in the East and Northwest sub-service areas.

Heat waves, when the daily maximum temperature during three consecutive days exceeds 30°C, as well as warm nights (minimum temperatures ≥ 23°C) both constitute medium risks for station power transformers. High night time temperatures will result in continued electrical use for air-conditioning, and also decrease the potential for transformers to cool down overnight. However, overall electrical demand is lower at night than during the daytime, and Toronto Hydro staff did not consider high night time temperatures to be as significant a concern as high daytime temperatures or heat waves from an electrical system point of view (Workshop 2).

High temperatures above 40°C, average temperatures over 30°C on a 24h basis, heat waves and high night time temperatures were also judged to be a medium risk for underground and overhead feeder systems due to high electrical demand for cooling and high ambient temperatures. Cables and power transformers were the two most vulnerable parts of these feeder systems in terms of heat. Under high demand, underground conducting wires and their housing undergo thermal expansion. This affects the structural integrity of the housing by causing wear and potentially leading to microfractures that are susceptible to water infiltration. Underground cables laid in close proximity or side by side, as is the case for underground feeders in the denser Former Toronto area, are also more susceptible to these expansion effects than underground feeders in the horseshoe area. Adjacent cables tend to heat one another up, and the increased heat reduces the cables' electrical transmission capacity. In overhead systems, cables under high demand will also lead to cable expansion and conductor sag. While this sag is generally accounted for in tree trimming and object clearance around power lines, excessive sag may be more prone to contacting objects and causing an electrical fault.

Feeder system power transformers are affected in a similar manner as their station counterparts. High ambient temperatures place additional demand from air-conditioning on transformers, while also affecting their ability to effectively cool. Overheating overhead transformers may fail or catch fire and will have to be replaced. In terms of relative risk, it should be noted that an overheating feeder line power transformer is less critical than an overheating station transformer, as the former serves fewer clients than the latter.

Underground dual radial, URD, compact loop and network systems afford increasing levels of redundancy for clients, due to their ability to supply electricity in the event of an outage through a different branch, loop or conduit of the feeder system. In this study, dual radial and URD feeders in the Former Toronto area were considered to be less able to cope with high electrical demand and mitigate outages than similar electrical feeder types in the horseshoe area. This is due to the fact that feeders in the Former Toronto area are already under high base load (denser environment), their equipment is generally older and cables running side by side increase the heat load and reduce their maximum capacity. Therefore, underground feeders in the Former Toronto area are considered to be slightly more at risk (+1 severity) to heat impacts as compared with similar feeder types in the horseshoe area.

Overhead feeder systems were judged to be slightly more at risk (+1 to +2 severity) than underground systems to temperatures above 40°C and to average temperatures above 30°C on a 24h basis. While electrical load demands may be similar for underground and overhead transformers, direct solar radiation and exposure to high ambient air temperatures can reduce the ability of overhead transformers to disperse heat. On the other hand, overhead transformers were judged to be less vulnerable to high night time temperatures than underground systems, due to increased circulation of cooler nighttime air around overhead transformers as compared to those located in underground vaults.

High ambient air temperatures were also judged to be medium-low risks for protection and control systems. Like station batteries, high temperatures will degrade the expected lifespan of batteries used to power the feeder protection and control systems in the event of a power failure.

Extreme Rainfall

The most significant medium risks from extreme rainfall events are related to the flooding of non-submersible vault-type electrical components kept below grade. Vaults below grade are usually equipped with either passive drainage systems or active pumping drainage systems to keep them from flooding. However, under extreme rainfall conditions, it is possible that the sewers to which these drainage systems are connected may themselves be at capacity, and without the ability to evacuate the water, some vaults may flood. In flooded vaults, non-submersible electrical equipment could be damaged, and an outage may occur. This is also a concern in some network type feeders in downtown Toronto, where old network protection equipment are not housed in submersible enclosures. Toronto Hydro is gradually installing submersible equipment in all below-grade vaults, but non-submersible equipment is still expected to be in present by the end of the study period. Furthermore, the equipment in flooded vaults cannot be accessed until the water is evacuated, creating a delay in responding to electrical incidents.

While not exclusively a problem related to heavy rainfall events, water infiltration into the ground and moisture around underground cables can lead to water treeing[20] and cracking of cable insulation. Deterioration of cable housing could lead to electrical faults if cracks become sufficiently large to allow ground moisture to serve as a pathway for electricity to ground.

[20] Tears in the cable's insulating layer caused by the presence of moisture and an alternating current's (AC) electric field.

It was noted in the workshop that extreme rainfall can be beneficial to overhead feeder systems. Salt residues from the wintertime and dust throughout the year can accumulate on electrical insulators. Moist conditions such as fog, mist or light rainfall can cause these accumulations to serve as conduits to ground, causing flashovers and potential pole fires and outages. Heavy rainfall events, especially in the early spring, are in fact beneficial for washing off the salt and dirt residues from insulators. Note that 27.6 kV and 13.8 kV lines are more prone to flashovers due to their higher voltages. It was noted in the workshop that 27.6 kV systems in particular may require more frequent cleaning than is currently the case in order to prevent flashovers, while flashovers do not tend to occur with 4.16 kV equipment.

High Winds

High winds over 70 km/h (but less than 90 km/h) were considered a medium risk to overhead power lines. While lines and poles are designed to withstand such wind speeds, it has been found that tree branches may begin to break at these thresholds and fall onto lines. Overhead conductors may also flail in the wind and contact branches. At the least, these tree contacts may cause momentary interruptions to electrical service. At the worst, tree branches and limbs may fall on and damage or sever power lines, potentially causing outages, fires and public safety hazards.

Lightning

Lightning strikes on overhead feeder systems was rated as a medium risk. Lightning arrestors installed on overhead power lines are designed to direct lightning surge currents to ground and protect pole mounted equipment such as transformers, switches and SCADA equipment. However, failure of the lightning arrestors can result in damaged equipment from lightning strikes and potentially lead to a localized outage.

Human Resources

Most of the human resource interactions with climate parameters (high heat, heavy precipitation, 15 mm of freezing rain, high wind, tornadoes, lightning and snowfall) were judged to be of medium risk. High heat conditions can make it dangerous to work on outdoor and overhead equipment for extended periods of time. For underground systems, high ambient temperatures can exacerbate hot conditions in vaults (heated by transformer operation), thereby also making it unsafe to work on equipment for extended periods of time. Workers tend to defer work under high heat conditions until temperatures above ground or within vaults cool sufficiently to allow safe continuous access. This may however cause a delay in the response to incidents on the electrical system.

Heavy precipitation, freezing rain and snowfall may make it difficult for all employees to travel to and from work, while also making it dangerous for field workers to get to equipment. During severe events such as high winds, tornadoes and lightning, workers apply their judgement and generally delay accessing equipment until the severe weather event has passed. Interestingly, the severity scoring of high winds at 70 km/h were slightly higher than scores for higher wind speeds (90 km/h, 120 km/h or tornadoes). This is because unsafe work conditions are very clear under extreme high wind events. However, at lower wind speeds, work conditions may appear to be acceptable, and workers may decide that the threat is reasonable given the need to restore electrical service. However, sudden, abrupt wind gusts could momentarily jeopardize worker safety.

As Toronto Hydro has occupational health and safety policies and procedures in place, the consequence of severe weather on workers tends to be delaying access and work on equipment until weather conditions, road access improves, and worksites are declared to be safe.

5.3 High Risk Interactions

The highest risks found in this study are related to structural damage and failure of electrical systems and components. In general, station equipment and overhead feeder systems were the two main system infrastructure categories susceptible to climate interactions that yield high risk interactions.

High Temperature

Days with peak temperatures above 40°C and days where average ambient temperatures exceed 30°C on a 24h basis are the two significant climate parameters rated as high risk for transmission and municipal stations. Days with peak temperatures above 40°C are currently a very rare occurrence, but are expected to occur on an almost annual basis by the 2030's and on an annual basis by the 2050's. Similarly, high ambient temperatures exceeding 30°C on a 24h basis are currently a rare occurrence, but may occur on an annual basis by the 2050's. In both cases, high electrical demand, coupled with loss of cooling efficiency, will cause station power transformers to overheat. In the most severe of cases, demand cannot be maintained without damaging station power transformers, which have an average replacement cost of around $500 K[21]. A coping mechanism employed by electrical utilities is to shed electrical load (load shedding), which entails instituting temporary outages in various sectors of the city in order to reduce load demand. For buildings and residents dependent on air-conditioning for cooling purposes, this represents a significant public health risk at a time of extreme heat events.

This high risk is especially relevant for transmission and municipal stations with low excess capacity by the 2030's and 2050's. As such, during periods of high demand, these stations have less excess capacity with which to meet electrical demand.

Freezing Rain and Ice Storms

There are three significant thresholds to consider for freezing rain and ice storm effects on the electrical distribution system. First, preliminary forensic analyses of outages from freezing rain indicate that 15+ mm of freezing rain is a trigger for the breaking of tree branches and limbs. These pose a threat to overhead feeder systems, and these freezing rain amounts have resulted in widespread outages in Toronto in the past due to tree contacts. The next threshold is 25 mm of freezing rain, which is the CSA design requirement for overhead electrical systems. Theoretically, overhead feeder systems, as well as the overhead exit lines at stations are supposed to withstand 25 mm of freezing rain (12.5 mm of radial ice accretion). However, such quantities of freezing rain and ice accretion on overhead infrastructure bring them to their structural design limits, which are further exacerbated by breaking tree branches and wind. Finally at 60 mm of freezing rain, the weight of ice accretion on overhead lines and station exit lines exceeds their design limit, and will likely cause them to collapse.

It should be noted that the high risk ratings for 15 mm and 25 mm of freezing rain on overhead feeder systems and station exit lines is based on probability of occurrence for the study period (probability scores of 7, event will occur during the study period)[22]. From an annual probability perspective, freezing rain events at 15mm and 25mm of freezing rain would actually result in medium risk ratings. As can be seen from Table 3-2 in Chapter 3, the current annual probability of occurrence of 15 mm of freezing rain is 0.11 days / year (1 in 9 year return period), and is projected to increase to 0.16 days / year (1 in 6 year return period) by the 2050's. The current annual probability of 25 mm of freezing rain is 0.06 days / year (1 in 17 year return period), and is projected to increase to 0.09 days per / year (1 in 11 year return period) by the 2050's.As the projected trend for 15 mm and 25 mm freezing rain events is increasing in the future, the interaction of these two climate parameters with overhead feeder systems and station exit lines are maintained as a high risk.

Similarly, it was found that 60 mm freezing rain events would actually fall into a medium risk category (study period probability of 4, annual probability of 1, severity score of 7). However, major ice storms are part of a pattern of risk that is similar to 25 mm freezing rain events. For this reason, it is maintained in the high risk category

High Winds

High winds and wind gusts at 90 km/h and 120 km/h were judged to be a high risk to overhead feeder systems. These wind speeds reach and exceed the design limits of conductor connections to support poles, and the poles

[21] Estimate provided through correspondence with Toronto Hydro staff.

[22] A comparison for freezing rain/ice storm lasting at least 6hr+ based on annual probability versus study period probability does not change the high risk rating.

themselves. Further compounding impacts is the potential for flying debris, such as broken tree branches and limbs, to further bring down overhead feeder systems.

The threats from high winds and gusts above 120 km/h were judged to be high risk due to wind forces on station overhead exit lines (exceeding design standard for poles). Furthermore, there is the potential for flying debris to damage station equipment at outdoor stations.

As is the case for freezing rain, it should be noted that the high risk ratings wind over 120 km/h were on overhead feeder systems and station exit lines is based on probability of occurrence for the study period (probability scores of 7, event will occur during the study period)[23]. However, from an annual probability perspective, events producing 120 km/h high winds would actual result in low and medium-low risk ratings for station and overhead feeder systems respectively. This is because the current annual probability of 120 km/h wind events is 0.05 days per year (1 in 20 year return period). This frequency is expected to increase during the study horizon, although the projected value is not known. These significant wind events are similar to the case of tornadoes, in that they are infrequent but can lead to significant damage to large areas of the distribution system if they occur (low probability, high severity events). As they are however expected to be more frequent than tornadoes, the 120 km/h wind – overhead systems interaction is maintained as high risk in this study.

Lightning

Lightning strikes on station equipment, notably power transformers, were rated as a high risk. Lightning arrestors at stations are designed to direct lightning surge currents to ground and protect electrical equipment. However, failure of the lightning arrestors can result in damaged equipment from lightning strikes and potentially causing an outage to an entire service area.

Human Resources

Heavy freezing rain events constitute a high risk for Toronto Hydro personnel. First, slippery surfaces make travel to and from work, and out to worksites dangerous for field crews. Second, field crews also have to contend with a layer of ice over electrical equipment, trees, and other overhead structures such as buildings. As such, the risk of injury to workers from freezing rain events remain even after the storm has passed due to the continuous ice loads on overhead power lines and trees, which may cause them to break without warning.

5.4 Special Cases – High Severity, Low Probability Events

Tornadoes

Tornadoes represent a high severity, low probability event. As mentioned in Chapter 3, while the likelihood of a tornado event touching down at a specific point or location is extremely small, the likelihood of a tornado occurring somewhere in the City of Toronto over study period (2015 – 2050) is in fact considerable. Furthermore, due to the lake breeze effect, northern portions of the city tend to have a high probability of seeing a tornado event, although it does not preclude an occurrence closer to the lakeshore. Tornadoes were judged to have catastrophic consequences on all above ground infrastructure, while underground infrastructure may become inaccessible due to windblown debris.

[23] A comparison for freezing rain/ice storm lasting at least 6hr+ based on annual probability versus study period probability does not change the high risk rating.

5.6 Special Cases – Low Severity, High Probability Events

Snowfall and freezing rain

The degradation of concrete and corrosion of steel materials (at grade and underground feeder systems) is a case of high probability, low severity events. These processes are accelerated by the application of de-icing salts during snowfall and freezing rain events. The application of salts can accelerate the corrosion of metal housing and enclosures of electrical equipment, resulting in shorter lifespans. It also affects the steel and concrete of vaults and cable chambers (civil equipment). Future warming associated with climate change is expected to decrease the number of days without snowfall, but the trend for freezing rain is expected to increase. Nonetheless, snowfall is expected to continue to be an annual event throughout the time horizon of this study. As such, degradation of civil structures will continue to be an issue for Toronto Hydro over the study period.

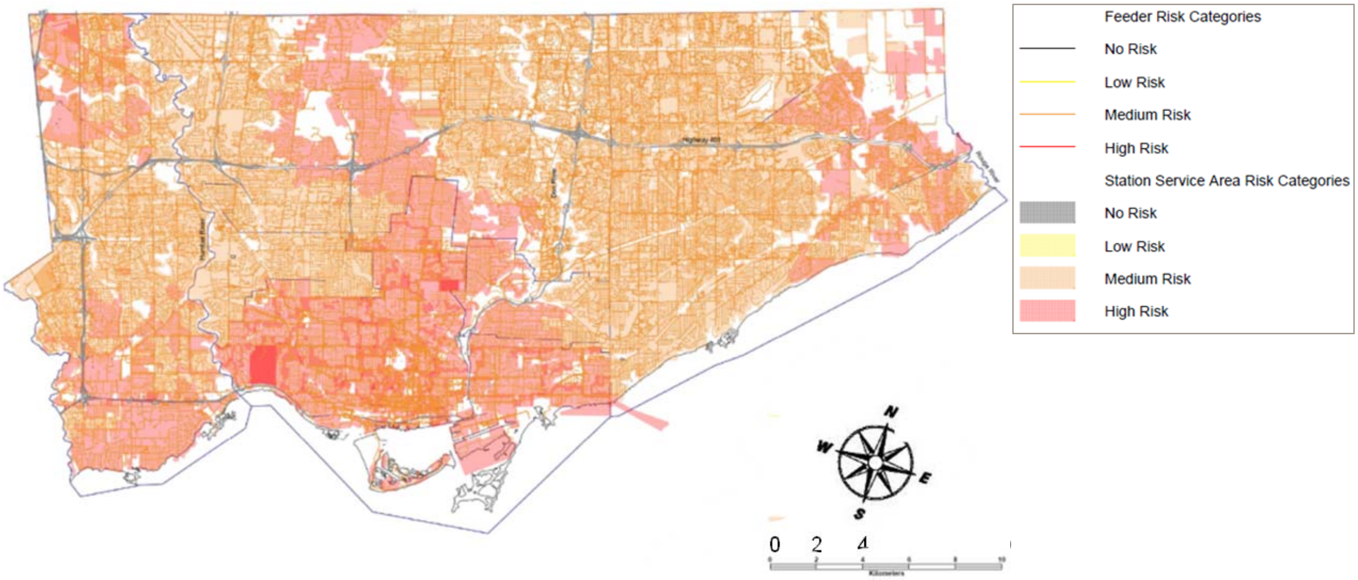
Underground electrical feeder equipment and civil structures located in the Former Toronto area received a slightly (+1) higher severity rating (and a medium-low risk rating) because the infrastructure is generally older than those found in the horseshoe area. It was found that older equipment and structures are more susceptible to degradation if corrosion had already begun (e.g. protective layers of paint may be worn off). Furthermore, older equipment may not be as resistant to corrosion as newer equipment due to the advancement of enclosure design and testing over time (Nema standard).

Some of this salt is dispersed by the moisture in the air, and can accumulate through the winter season on insulators on poles. These salt accumulations can cause electrical short circuits that could result in pole fires. Loop feeder systems are judged to be of lower risk than radial systems in the event of a short circuit or fire due to the potential to provide power temporarily through another loop of the feeder.

5.7 Mapping Risk Results

The mapping of risks provides complementary information to the risk assessment matrix, and facilitates a spatial understanding of low, medium and high risk interactions, and vulnerabilities (i.e. the medium and high risk interactions). For example, maps can provide an indication of the areas of vulnerability of overhead and underground infrastructure with respect to different kinds of weather events. Furthermore, the mapping exercise actually provides a new set of information on how vulnerabilities stemming from stations can combine with vulnerabilities to feeder systems. In some cases, vulnerabilities stem primarily from station assets (e.g. 120km/h wind and underground feeder assets), while in other cases, both station and feeder vulnerabilities to weather events contribute to an area of greater vulnerability within the city (i.e. freezing rain affecting both station and overhead feeder assets). The following section provides some spatial observations about the four climate parameters affecting electrical distribution infrastructure. All mapping results are provided in **Appendix E**.

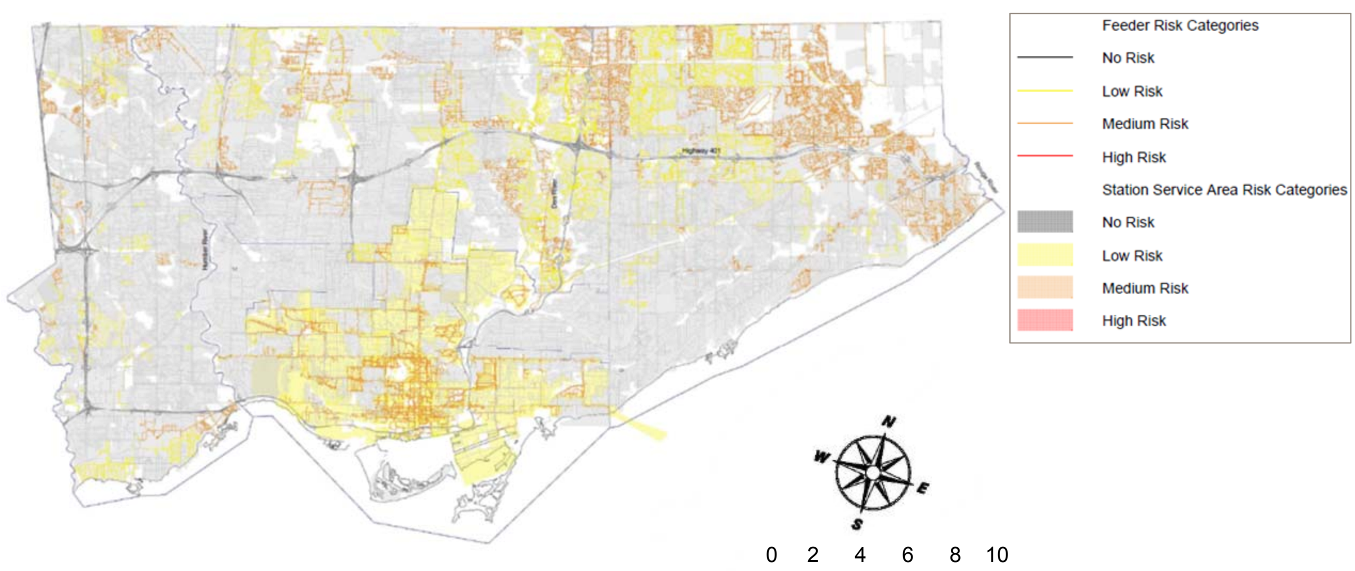
Figure 5-1 Risk Map, High Temperature Above 40°C, 2050's



Vulnerabilities from high heat events stem primarily from projected available station capacity by the 2050s, as this study did not find that vulnerabilities varied significantly (all rated medium risk) for feeder assets. Vulnerabilities to high heat events are more heavily concentrated in the Former Toronto area, although several horseshoe area stations would also be vulnerable during high heat events (Figure 5-1).

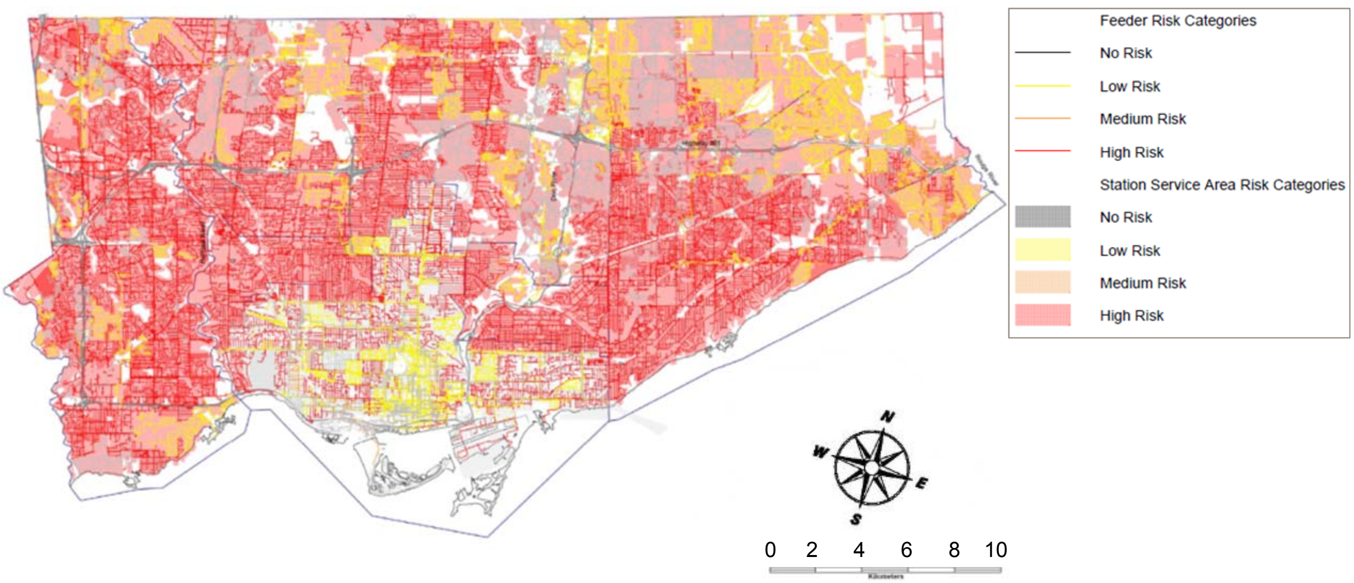
In terms of potential heavy rainfall risks to Toronto Hydro infrastructure, underground feeder systems that may be subject to flooding are located largely in the Former Toronto area and northeastern sections of the horseshoe (Figure 5-2). Some transmission station service areas in the Former Toronto area are marked as low risk due to the presence of some switchgear equipment that will likely remain in basements through the study period. Note however that sump pumps in stations make the probability of flood damage in stations from heavy precipitation less likely.

Figure 5-2 Risk Map, Extreme Rainfall, 100 mm in less than 24h, 2050's



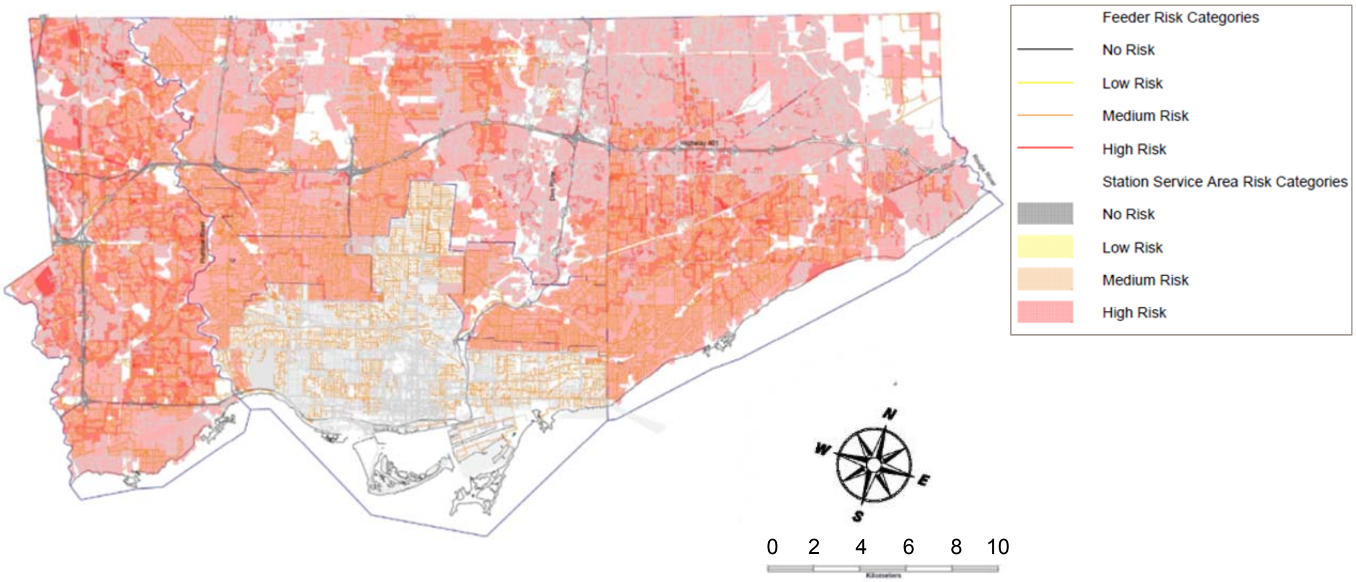
Toronto Hydro has a significant quantity of overhead distribution systems which are at vulnerable to extreme freezing rain, ice storms, high wind and tornado events. These feeder vulnerabilities combine with the fact that stations in the horseshoe area have station exit lines that are outdoors. This combination makes certain portions of the horseshoe particularly vulnerable to heavy freezing rain events and ice storm. Figure 5-3 shows the areas of vulnerability stemming from 25 mm of freezing rain, and is indicative of extreme precipitation/wind related vulnerabilities to overhead systems across Toronto.

Figure 5-3 Risk Map, 25 mm Freezing Rain, 2050's



Lightning strike vulnerabilities are largely concentrated in the horseshoe area, where both outdoor station equipment and overhead feeder systems are predominant. However, overhead feeder systems in the the Former Toronto area are also vulnerable (Figure 5-4).

Figure 5-4 Risk Map, Electrical Distribution Systems Potentially Affected by Lightning Strikes



There are several caveats that should be mentioned with respect to interpreting mapping results, due in large part to the fact that risk ratings were evaluated based on general system characteristics. Localized site characteristics that may mitigate or worsen risk ratings were not adequately captured in the mapping exercise. They include:

- Local geographic characteristics, assets and features. There may be local site characteristics such the tree canopy cover, types of trees, presence of buildings or other overhead structures, which may exacerbate weather events (e.g. wind) or shelter infrastructure from impacts. The presence of low lying areas (e.g. bowls, flood plains) was also not considered. This level of detail, provided by a full site inspection and digital terrain mapping, were not available for this project. Such information would be useful in refining the risk ratings and mapping for extreme rainfall, freezing rain and wind;

- Areas with lower drainage capacity due to configuration of city storm drainage infrastructure. This type of information requires a very detailed understanding of city infrastructure, which was not available for this study. Furthermore, this level of data is most useful when combined with digital terrain mapping in order to identify low lying areas with problematic drainage. Finally, future projections as to how city infrastructure might evolve over time were also not available for this project;

- The moderating effect of Lake Ontario. As noted in Chapter 3, the lake can play a significant role in influencing temperature and humidity along the lakeshore. For example, the lake effect can moderate temperatures during heat waves and can reduce the possibilities of freezing rain or snow falling on areas closer to the lakeshore. The extent and intensity of the lake effect can vary depending on the event and weather conditions. It was not possible to estimate the geographic extent of the lake effect, or by how much the probability scoring for certain climate parameters may be affected. As such, the lake effect's moderating influence was not taken into account sufficiently in the risk assessment and mapping exercise;

- Local electrical configurations and characteristics. There are likely cases where location specific electrical equipment may make certain feeder or station systems inherently more robust or redundant than would be the case of the general class of equipment. For example, additional feeder ties, loops or circuits could make certain feeders more redundant in the event of a downed power line. The age of equipment, their future replacement schedule will also have an effect on their risk rating. This level of detail is not captured at level of analysis undertaken in this study;

- For the extreme rainfall risk map, it should be noted that the mapping of transmission stations includes all stations. Information identifying the location of the stations whose batteries and switchgear are located below grade was not available. Further analysis is required to identify the precise locations of transmission with below grade assets in order to get a better mapping of flood related risks.

In spite of these shortcomings, the mapping exercise represents a useful first approximation of spatial nature of electrical system vulnerabilities to climate change. Furthermore, this mapping information can be more easily combined with other layers of information such as technical hazard information (e.g. flood mapping), physical locations (e.g. emergency resource centres, hospitals, transportation networks) and social vulnerability indices (e.g. age, income, population density, etc.) from other sources (e.g. TRCA, City of Toronto) to produce further mapping studies and in depth analyses to suit the needs of other policy makers.

6 Engineering Analysis

This chapter presents the results of the Step 4 of the Protocol, the Engineering Analysis. The purpose of Engineering Analysis is to conduct a further assessment of the system-climate interactions that were rated as a medium risk (interactions scoring between 14 and 35). For these interactions, the engineering analysis attempts to evaluate whether the infrastructure is vulnerable to a changing climate. To do so, the various factors that affect the load and the capacity of the infrastructure for the study time horizon are calculated. However, quantitative calculations of load and capacity were not always possible to make due to a lack of data to support such an analysis. For this reason, professional judgment is also applied in the engineering analysis. Infrastructure which is found to be vulnerable is passed to Step 5, while those which were not were discarded from further consideration.

In total, nineteen medium risk interactions were analyzed. Fifteen of them were deemed vulnerable and passed to Step 5, while 4 were discarded from further analysis. The following table summarizes the results of the engineering analysis. A brief description of the reasoning behind the results for each of the medium risk interactions is presented in this chapter, while the full engineering analysis can be found in **Appendix G.**

Table 6-1 Engineering Analysis Results

	Affected infrastructure	Climate Parameter	Further Action Recommended
	Municipal and Transmission Stations and Communications Systems		
1.	Transmission and municipal stations	High temperature above 25°C and above 30°C	Yes
	Protection and control systems	All temperatures	
2.	Transmission stations	High temperature above 35°C	Yes
3.	Transmission stations	High temperature above 40°C and average temperature > 30°C	Yes
4.	Transmission stations	Heat wave and high nighttime temperatures	Yes
5.	Transmission and municipal stations	Freezing rain, ice Storm 60 mm	Yes
6.	Municipal stations	High temperature	Yes
		Underground and Overhead Feeders	
7.	Underground feeders	High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime	Yes
8.	Underground feeders	Extreme rainfall	a. Feeders/water treeing: Yes b. Nun submersible vault: Yes c. Above ground stations: No d. N/W feeders: Yes
9.	Padmount stations	High winds 120 km/h	No
10.	Overhead feeders (radial and loop)	High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave	Yes
11.	Overhead feeders (radial)	High nighttime temperatures	No
12.	Overhead feeders (loop)	Freezing rain, ice Storm 15 mm	Yes
13.	Overhead feeders (radial and loop)	Freezing rain, ice Storm 60 mm	Yes
14.	Overhead feeders (radial and open loop) and SCADA system	Lightning	Yes
15.	Overhead feeders (radial)	Snow > 5 cm and snow > 10 cm	No
		Civil Structures	
16.	Civil structures: underground feeders (Former Toronto)	Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 6hrs+ (combination of events)	Yes
17.	Civil Structures: underground feeders (Former Toronto)	Snow > 5 cm and snow > 10 cm	No, but combinations of climates need additional study.
18.	Civil structures	Frost	Yes
19.	Human resources	All climate parameters	Yes

6.1 Municipal and Transmission Stations and Communications Systems

1. High temperature above 25°C and above 30°C / transmission and municipal stations and all Temperatures / protection and control systems

Further action recommended. Under higher temperatures, battery life expectancy (e.g. around 10 years) may decrease. Toronto Hydro has already encountered problems with some batteries failing prior to their expected lifespan..

2. High temperature above 35°C / transmission stations

Further action recommended, conclusions for high temperature and power transformers also apply (see Chapter 7). Transmission station designers will need to take into account the significant increase in days with maximum temperatures above 35°C, which reduces station capacity while, on the other hand, experiences an increased load demand. At the moment, no load growth rate for the period of this study was estimated. The recommendations given in Chapter 7 for transmission stations and maximum temperature above 40°C / average temp above 30°C also apply to this interaction.

3. High temperature above 40°C and average temperature > 30°C / transmission stations

Further action recommended. Most of the transmission stations considered in this study were judged to be vulnerable (high risk rating) to high temperatures. The stations in the Horseshoe received a medium-high risk score (35) due to the application of the concept of excess capacity, which is qualitative and notional (refer to the **Appendix F**). As such, it is recommended that transmission stations receiving a medium-high risk score be considered vulnerable to extreme high temperatures as part of a consistent pattern of risk. This will also help Toronto Hydro to adopt a consistent approach in the design, operations and maintenance of stations.

4. Heat wave (+30°C) and high nighttime temperatures (+23°C) / transmission stations

Further action recommended. Power transformers are vital equipment in the distribution of electricity and high temperatures have a significant impact on the capacity of the transformers. For these reasons, the conclusion of this report for temperature above 40°C and for high daily average temperature > 30°C are also relevant to the heat wave and high nighttime temperature parameters.

5. Freezing rain/ice storm 60 mm ≈ 30 mm radial (major outages) / transmission stations and municipal stations

Further action recommended. This interaction is part of a similar pattern of vulnerability as 25 mm freezing rain events. Therefore, solutions for 25 mm events are also relevant to mitigating heavy freezing rain events of ~ 60 mm.

6. High temperature (+35°C,+ 40°C, average temperature > 30°C, heat wave, high nighttime temperatures) / municipal stations

Further action recommended. High temperature and combinations of high temperature, high average temperature, high nighttime temperature and high load demand will have consequences on the capacity of the power transformers and cables.

6.2 Underground and Overhead Feeders

7. High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime / underground feeders

Further action recommended. Toronto Hydro replaces cables based on asset life replacement cycles or premature failures. However, it is projected that climate change related high temperatures could create higher demand for cooling, and may place greater stress on cables and lead to increasing occurrences of cable failures. Therefore, high heat impacts on cable was deemed to be a vulnerability.

8. Extreme rainfall / underground feeders

a. Feeders: Water treeing of the cables, flooding

Further action recommended. Climate change related stresses (i.e. higher temperature, higher loading, flooding from extreme rainfall) will continue to stress underground cables and constitute a vulnerability for Toronto Hydro.

b. Non-submersible equipment failure in vault type stations below ground in the Horseshoe Area (Former Toronto has a high risk result)

Further action recommended. While Toronto Hydro is gradually replacing vault type non-submersible equipment with submersible versions, non-submersible vault type equipment is likely to remain in the system over the study period.

c. Above ground vault stations, access to the vault station and to the station equipment could be limited due to localized flooding of streets around the vault station, or at the station itself

No further action required. This impact does not relate to station load or capacity. The consequence is that the access to the vault stations or the stations equipment could be temporarily impeded. Impact is localized and temporary, and was not judged to warrant further action beyond current practices.

d. Network feeders: old N/W protectors are not submersible

Further action recommended. The old N/W protector may not operate properly if flooded. However, failure of the N/W protector will not automatically result in an interruption to the customer, since network systems are highly redundant. Toronto Hydro is installing new N/W protectors that are submersible, but there may still be older non-submersible N/W protectors in the systems, particularly in downtown over the study period. Further study could be undertaken to evaluate the cost of replacing old network protectors prior to the end of their expected lifecycle against the frequency and consequence of old N/W protectors being flooded.

9. High winds (120 km/h) / padmount stations on distribution network (Former Toronto)

No further action required. The damaged equipment will result in an overall or some loss of service capacity and function. However, it is judged that flying debris is too much of a random occurrence to warrant further action.

10. High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave / Overhead power lines (radial and loop)

Further action recommended. Higher temperatures will have impacts on the overall capacity of the power lines. In the downtown area, there are critical, constrained areas (i.e. built up zones) where added conductor/transformer capacity may be difficult to implement.

11. High nighttime temperatures / Overhead power lines (radial)

No further action required. Night time temperatures with minimum ≥ 23°C in and of itself is not a significant concern for Toronto Hydro in terms of electrical service provision as peak demand has subsided. However, it is important to note that high daily temperatures in combination with high night time temperatures are a concern. This has been considered under different climate-infrastructure interaction, average temperature over 30°C on a 24 h basis, so this particular interaction does not warrant further action.

12. Freezing rain - ice Storm 15 mm and high winds 70 km/h / Overhead feeders in loop configuration

Further action recommended. The risk assessment of radial systems resulted in a high risk rating for this interaction. In overhead loop systems, it was hypothesized that their more redundant configuration would reduce customer interruptions, affect fewer clients or cause outages of shorter durations, thus yielding a high-medium risk rating of 35. However, the frequency of freezing rain events are projected to increase slightly by the end of the study horizon compared to present day (see table 3-2). The tree canopy may also be weakened by increased disease threats. Finally, freezing rain events tend to be widespread, and there is no reason to believe that both branches of an overhead loop circuit might not be equally susceptible to damage. For all of these reasons, all overhead power lines, irrespective of electrical configuration, were deemed as vulnerable.

13. Freezing rain/ice storm 60 mm ≈ 30 mm radial (major outages) / overhead lines (radial and loop)

Further action recommended. See explanation for freezing rain and stations (item 5 above).

14. Lightning / overhead power lines (radial and open loop) and SCADA system

Further action recommended. It is difficult to predict the increase of lightning strikes for the study period; however it is interesting to note that the probability of a lightning strike in an area of 0,015 km^2 anywhere within the City of Toronto is very high for the study period. At the moment, lightning strike intensity, the number of lightning arrestors/km and arrestor performance are not monitored by Toronto Hydro. Given this uncertainty, and since lightning strikes are currently a frequent source of outages, lightning strikes were judged to be a continued vulnerability.

15. Snow > 5 cm and snow > 10 cm / overhead power lines (radial)

No further action required. The number of snow days is highly variable. The trend seems to be decreasing, but snow days will still occur annually. During the workshop, Toronto Hydro mentioned having problems regarding insulator tracking leading to pole fires especially at higher voltages (13.8 kV and 27.6 kV) and switch failures. However, Toronto Hydro is already monitoring and dealing with this issue.

6.3 Civil Structures

16. Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 6hrs+ (combination of events) / civil structures: underground feeders (Former Toronto)

Further action recommended. Vaults and chambers already suffering from degradation issues will deteriorate more rapidly over time. From THESL (Toronto Hydro, 2014a): *As below-grade structures age, the greatest concern becomes structural strength. Structural deficiencies affecting vaults include degradation of concrete and corrosion of supports such as beams and rebar. Once degradation and corrosion sets in, conditions can deteriorate rapidly and in many cases from one season to the next. Of particular concern is the winter season when moisture and water enter in below*-grade *structures, freezes and thaws, and carries with it salt that has been used at grade to melt ice and snow.*

While maintenance can reduce the rate of deterioration, incidence of extreme rainfall, snowfall, freezing rain and the application of road salt will persist throughout the study period and continue to contribute to the premature aging of civil structures. While, it could not be determined in the study whether premature aging of civil structures will be exacerbated by a changing climate, this issue will persist over the study period and is therefore judged as an on-going vulnerability

17. Snow > 5 cm and snow > 10 cm / civil structures: underground feeders (Former Toronto)

No further action required, but combinations of climates events require additional study. As days with snow will probably decrease, the snow days alone were not judge to be a significant vulnerability. However, snow days will still occur over the study period, and in combination with extreme rainfall, freezes and thaw, freezing rain, and the continued application of road salt, premature degradation of civil structures was judged to be an ongoing vulnerability for Toronto Hydro.

18. Frost / civil structures (overhead and underground feeders)

Further action recommended. While the threat of frost is decreasing over the study period, it is noted that frost penetration will still occur with occasional extreme cold weather. Since Toronto Hydro already experiences problems with frost and its civil infrastructure, frost impacts are judged to be a vulnerability.

6.4 Human Resources

19. All climate parameters / human Resources

Further action recommended. While occupational health and safety procedures will continue to be in place in the future, human resources will continue to be vulnerable to climate change related weather events due to the need to travel, access, and work on equipment in spite of the weather.

7 Conclusions

The Phase 2 study presents a climate change based vulnerability assessment of electrical distribution infrastructure. It seeks to inform future investigations, planning and investment decisions on system and component vulnerabilities, and to support efforts to enhance the resilience of the electrical system. This chapter presents Step 5 of the Protocol and covers electrical distribution system vulnerabilities within the City of Toronto, adaptation options and areas of further study.

7.1 Vulnerabilities to a Changing Climate

The Phase 2 employed a high level risk based screening methodology to determine where infrastructure vulnerabilities to climate change may be present. All high risk infrastructure-climate parameter interactions, as well as medium risk interactions assessed as vulnerable through the engineering analysis comprise the vulnerabilities identified for Toronto Hydro's electrical distribution system to a changing climate. These vulnerabilities can be divided into five groups based on how climate parameters affect the system. The following paragraphs summarize these vulnerabilities, while table 7-1 provides more detailed information by infrastructure-climate parameter interactions.

High Ambient Temperatures – Station and Feeder Assets

High ambient temperatures create problems for the distribution system because of the compounding effect of high demand (e.g. for cooling) and high ambient temperature affecting equipment cooling and electrical transmission efficiency. Two specific climate parameters were of most significant concern, daily peak temperatures exceeding 40°C (excluding humidity) and daily average temperatures exceeding 30°C. In these cases, the climate analysis found that such extreme temperatures have occurred only rarely in the past, but are projected to occur on an almost semi-annual to annual basis by the 2030's and 2050's respectively. Through preliminary demand and supply growth projections completed for this study, these vulnerabilities were identified based on the notion that extreme heat will generate electrical demand for cooling in areas where station excess capacity is projected to be marginal. Furthermore, such temperature extremes may cause equipment, notably power transformers, to operate beyond their design specifications and increases the likelihood of failure. It is anticipated that vulnerability to high heat events will be concentrated in the Former Toronto area, although there are several horseshoe station service areas which would also be vulnerable.

Freezing Rain, Ice Storms, High Wind and Tornadoes – Overhead Station and Feeder Assets

Freezing rain, ice storms, high wind and tornado events cause immediate structural issues for overhead distribution assets, as they have the capacity to exceed the design limits of equipment and their supports. Outages may result from damage to equipment arising from direct forces applied by climate parameters (e.g. wind, weight of ice) or by other objects (e.g. tree branches, flying debris). These kinds of events affect outdoor station and feeder assets, which are largely concentrated in the horseshoe service area. It is important to emphasize that Toronto Hydro has experienced problems related to freezing rain, ice storms (up to 25 mm) and high winds (up to 90 km/h) in the past. These events are projected to continue in the future, but continue to occur on a less than annual or even decadal frequency. More severe ice storms (60 mm), high winds (over 120 km/h) and tornadoes (EF1+) have been extremely rare in the past, and while there is a lack of scientific consensus on projected future frequencies for these extreme events, they are likely to remain rare in the future. Nevertheless, the damages caused by these kinds of events can be severe. Therefore, they were judged as ongoing and future vulnerabilities for Toronto Hydro.

Extreme Rainfall – Underground Feeder Assets

Extreme rainfall events may potentially flood underground feeder assets, which are largely concentrated in the Former Toronto and northeastern horseshoe areas. Toronto Hydro is aware of these issues in relation to its assets and has programs to replace non-submersible equipment with submersible type equipment, to relocate equipment where possible. However, due to the large quantity of underground feeder assets across the city, replacement and reinforcement of underground assets will be a gradual and ongoing activity for Toronto Hydro over the study period. As such, some underground feeder assets may remain an area of vulnerability for Toronto Hydro.

Snowfall, Freezing Rain - Corrosion of Civil Structures

The degradation of civil structures (i.e. concrete and steel), which is accelerated by humidity and the presence of de-icing salts, was identified as a potential area of vulnerability to climate change. Corrosion is already an ongoing issue for Toronto Hydro and current assets have a design lifespan which accounts to a great extent for corrosion issues. However, it is not clear from this study whether the climate change stresses will exacerbate the problem. While snowfall days are generally expected to decrease with a warming climate, they will continue to occur annually through to the 2050's. As a result, and in combination with freezing rain events, the application of de-icing salts will also be applied annually through the study horizon. Nonetheless, it should be emphasized that corrosion represents a long-term and on-going vulnerability for Toronto Hydro.

Lightning – Overhead Feeder Assets

Based on workshop feedback and an examination of Toronto Hydro's ITIS outage data, Toronto Hydro recognizes that lightning impacts are a significant source of outages on the distribution system today. While there have been advances in predicting lightning activity, there was insufficient data available on lightning strike intensity and arrester performance to suggest how future lighting activity may affect the electrical system. For these reasons, this study suggests that lightning activity will continue to be an area of vulnerability.

7.2 Adaptation Options

Adaptation options are suggested for all the infrastructure-climate parameter interactions identified as vulnerabilities. The Protocol classifies adaptation options in four possible categories:

- remedial engineering actions which aim to strengthen or upgrade the infrastructure;
- management actions to account for changes in the infrastructure capacity;
- continued monitoring of performance of the infrastructure and impacts; and
- further study required to address gaps in data availability and data quality.

Adaptation options by infrastructure-climate parameter interaction are presented in Table 7-1.

Table 7-1 Vulnerabilities and Adaptation Options by Infrastructure Asset, Climate Parameter

Affected infrastructure	Climate Parameter	Adaptation Option	Details
Stations, Communications and Protection Systems			
1. Transmission stations, municipal stations, protection and control systems Critical component: batteries	High temperature above 25°C	Further study required	Toronto Hydro has experienced problems with station batteries failing short of expected lifespans (i.e. approximately 10 years). Operating batteries in rooms where the ambient temperatures increases above 25°C is a contributing factor to premature battery failure (Toronto Hydro, 2014c). As battery rooms are not temperature controlled, Toronto Hydro could monitor how ambient temperatures of rooms within stations housing batteries fluctuate during the warmer summer months and evaluate whether additional measures are needed (e.g. review of battery technical specifications, including aging factor) to reduce battery degradation.

Affected infrastructure	Climate Parameter	Adaptation Option	Details
2. Transmission stations, municipal stations Critical component: power transformers	High temperature above 35°C, 40°C Average daily temperature > 30°C Heat wave High nighttime temperatures	Further study required	Given the increased frequency of high heat conditions in the future, coupled with continued demand growth, infrastructure owners (Toronto Hydro and Hydro One), could conduct a could conduct a further study evaluating the technical and financial feasibility of installing transformers with a higher capacity, or installing more transformers at stations (shared load) where space permits. Another possibility is to evaluate the technical and financial feasibility of increasing the design standard for current power transformer equipment, for example, by designing to a daily average ambient temperature higher than 30 °C (35 °C) and maximum temperature with a higher temperature than 40°C (45 °C). Finally, these measures should be complemented by continued demand side management /energy conservation programs.
3. Transmission stations: only outdoor stations 4. Municipal stations: Horseshoe area outdoor stations Critical component: Overhead exit lines (for freezing rain and high winds parameters)	Freezing rain/ice storm : 25 mm, 60 mm High winds : 120 km/h and tornadoes	Management actions and further study required .	Major freezing rain, ice storm, high wind and tornado events are not expected to be an annual occurrence in the future, but will still likely occur over the study period. Station exit lines, either overhead ones or where underground cables surface, are a particular point of vulnerability, as downed exit lines can sever power supply to the entire service area. Toronto Hydro could monitor the frequency of damage to station exit lines and poles across a range of potential weather threats (freezing rain, high winds) to evaluate whether this critical portion of the distribution network requires strengthening. Toronto Hydro could also consider a station by station study of surroundings to identify areas around stations susceptible to generating flying debris (e.g. trees, buildings). Emphasis should also be placed on optimizing the emergency response and restoration procedures to reduce system down time. Note that Toronto Hydro is already undertaking a review and enhancement where necessary of response planning, dispatching operations, prioritization of restoration activities, coordination with other utilities, response team training and preparation.
Arresters (for lightning parameter)	Lightning	Monitoring activities	Lightning events and strikes are difficult to predict, but are likely to increase in frequency and intensity. However, lightning strike intensity and arrester performance is not currently monitored. Given the importance of lightning strikes as a cause of outages, it is recommended that the lightning activities (e.g. frequency, intensity), soil resistivity (i.e. decreased soil moisture from longer and hotter summers) and impacts on the system could be more closely monitored to provide more information regarding the risks of lightning strikes. For example, where high voltage arresters are installed, counters (if not already present) could also be installed to check if a particular phase or transmission line suffers from an exceptionally high number of overvoltages leading to arrester operation. Lightning strikes on the building housing stations could be investigated to determine whether they resulted in any overvoltage impacts. If further studies on lightning activity result in a better definition of lightning characteristics and impacts, or if monitoring indicates a higher rate of failure, a review of actual design practices could be undertaken.

Affected infrastructure	Climate Parameter	Adaptation Option	Details
Feeders, Communication and Protection Systems			
5. Underground feeders Critical component: cables and power transformers	High temperature above 35°C, 40°C Average daily temperature > 30°C Heat wave High nighttime temperatures	Monitoring activities	For power transformers, see discussion above on station power transformers (see row 2). For cables, increased temperature operation tends to reduce the dielectric strength of the cables. Toronto Hydro is currently trialing cable diagnostic testing techniques as a method of detecting vulnerabilities in cables. If cable testing techniques prove reliable in detecting potential failures, Toronto Hydro could consider extending diagnostic techniques to all cables to monitor heat stress impacts on cables to evaluate whether high design standards or more frequent replacement is required.
6. Underground feeders : Submersible type Critical component: cables	Extreme rainfall: 100 mm <1 day + antecedent	Monitoring activities	The presence of water can lead to an electrical failure of the cables (water treeing) and/or reduce the dielectric strength of cables. Cable diagnostic testing can be employed to monitor the degradation of underground cables. This study also supports Toronto Hydro's program to replace and renew older cable assets with moisture and tree resistant underground conductors such as TRXLPE cables. The development of flood risk mapping, coupled with historical registry of flood related equipment failures could enhance the identification of areas for priority intervention.
7. Underground feeders: Vault type – Below ground Critical component: non-submersible equipment	Extreme rainfall: 100 mm <1 day + antecedent	Remedial engineering actions	Toronto Hydro is currently upgrading non-submersible equipment located in below grade vaults with submersible equipment, or relocating them above grade. The development of flood risk mapping, coupled with historical registry of flood related equipment failures could enhance the identification of areas for priority intervention.
8. Underground feeders: 13.8 kV Network systems	Extreme rainfall: 100 mm <1 day + antecedent	Remedial engineering actions	Many old network protectors are not submersible, particularly in the downtown area. The current Toronto Hydro standard is to use submersible network protectors when replacing old equipment. Further study could be undertaken to evaluate the benefit and cost of replacing old network protectors prior to their end of life versus replacement at their end of life (i.e. potential for flood damage and outages prior to replacement).
9. Overhead feeders (Radial and loop) Critical component: power transformers and conductors	High temperature above 35°C High temperature maximum above 40°C Average daily temperature > 30°C Heat wave	Monitoring activities	Climate change is projected to increase the frequency of high heat conditions in the future. Coupled with continued demand growth, this is projected to increase heat stresses on overhead distribution feeder assets. However, unlike the case with station transformers, where projected heat and capacity reveal a clear vulnerability in terms of supply capacity, it is not clear whether high temperatures will have the same impact across the distribution feeder system (i.e. are there bottlenecks to supplying electricity during periods of high heat at certain stations or across the grid?). Toronto Hydro should continue to monitor key grid operational indicators for distribution transformers, such as load currents, billing data, transformer oil and ambient temperatures. This information can be used to help evaluate whether distribution line capacities are sufficient to handle increased electrical loads.
10. Overhead feeders (Radial and loop) Critical component: conductors	Freezing Rain/Ice storm: 15 mm and high winds 70 km/h	Management actions and remedial engineering actions	Toronto Hydro is already experiencing outages caused by tree contacts and is planning to increase its vegetation management activities. This study supports the need for increased tree trimming practices around overhead power lines and use of tree proof conductors in areas where outages due to tree contacts have been frequent.
11. Overhead : Radial and Loop Critical component: poles	Freezing rain/ice storm: 25 mm High winds: 90 km/h and 120 km/h, tornadoes	Management actions and further study required	See recommendations for stations above on freezing rain and tornadoes (see row 3).

Affected infrastructure	Climate Parameter	Adaptation Option	Details
12. Overhead power lines (radial and open loop) and SCADA system	Lightning	Monitoring activities	See recommendations for stations above on lighting (see row 3).
Civil structures			
13. Civil structures: Underground feeders (Former Toronto)	Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 60 mm (combination of events)	Further study required	While maintenance can mitigate the risks of civil structures deterioration, changing climate conditions (e.g. freezing rain, rainfall, freeze-thaw) may exacerbate premature degradation issues. However, it could not be determined in this study whether current design standards are sufficient to withstand future climate - salt and moisture related degradation. Further study could be undertaken to estimate salt/moisture corrosion effects in relation to climate change.
14. Civil structures: transmission and municipal stations, underground feeders	Frost	Further study required	The nature of the frost heave impacts to civil structures was not sufficiently evaluated within this study. Further study can be undertaken to identify whether there are any specific location, ground condition and structure combinations which contribute to frost heave impacts.
Human Resources			
15. Human Resources	Heat, freezing rain, wind and tornadoes	Management actions	Toronto Hydro applies an occupational health and safety manual. Toronto Hydro is already conducting a review of its procedures in light of future extreme events to determine whether modifications in procedure or training are needed.

7.3 Other Areas of Study

Additional climate and infrastructure related areas of further study that can be used to enhance the understanding of electrical system vulnerabilities to climate change are listed below.

Climate

- Increase monitoring of important climate parameters across the city. For both the climate assessments and forensic analyses, a lack of observational data made understanding climate risk challenging and introduced uncertainties, particularly for specific climate parameters such as wind gusts, hourly rainfall measurements, and freezing precipitation accumulations. New monitoring would provide important benefits, including:
    - Addressing gaps in historical data;
    - Facilitating comparisons between sites across the city;
    - Improving the spatial resolution of the climate monitoring network, increasing the likelihood of capturing important meteorological events; and,
    - Providing additional data to assist in detecting new and emerging trends sooner than would be possible using the current network.
- Enhance details about weather impacts contained in the ITIS database. Although information contained within the database was extremely useful and yielded important insights, there were still gaps in the details of weather related outages which limited the evaluation of impacts;
- Refine and expand forensic investigations (see **Appendix C**) completed in this Phase 2 study. Several climate parameters, individual climate events and impacts were not investigated thoroughly due to the scope of the present study. In particular, further analyses could be done on:
    - Lake modified air and lake breeze influences on atmospheric hazards, especially extreme temperatures, ice accretion events, and severe thunderstorms (including extreme rainfall, downbursts/microbursts, and tornadoes);
    - December 2013 ice storm and other ice accretion events, particularly to help refine understanding of apparent variations in impacts between different sections of the city.

    - Temperature gradients across the city during periods of extreme heat. For example, why do some days show greater temperature gradients across the city than others, and what impact does this have on the system?
- Monitor and study the complex interaction between changes in tree growth, pest and disease conditions and resultant changes in risk to overhead systems. This could include investigating
    - The extent to which accelerated tree growth affects tree strength, and specifically resistance to wind and ice accretion loading;
    - Emerging and/or worsening tree pest and disease conditions which could reasonably be expected within the City of Toronto in the coming decades, and what potential changes in risk these will pose to overhead systems.

Infrastructure

- Site specific electrical configuration and area characteristics were not collected due to the scope of this study and scale of infrastructure system being analyzed (e.g. land use changes, high rise and condo development, population growth, terrain elevation, sewers, storm sewers, roads, tree canopy and tree type, buildings). Specific site characteristics, equipment age, or unique or uncommon equipment can alter sensitivity and vulnerabilities. Further study approaches could adopt a smaller spatial scale (e.g. station service areas, neighbourhoods) to reduce these scope and level of effort challenges and identify more site specific vulnerabilities;
- The scope of study and level of effort did not permit a detailed analysis of system performance and outage management (i.e. simulations of power rerouting or contingencies under different outage scenarios to various parts of the system). Further study approaches could adopt a smaller spatial scale (e.g. station service areas, neighbourhoods) to reduce these scope and level of effort challenges and permit a more detailed study and understanding of system performance and outage management;
- Smart Grid Data: Toronto Hydro has recently begun collecting information about outages from its grid based on smart grid feedback. Data history was short and not reviewed in this analysis. Further study examining smart grid data can be used to identify problem areas due to high load demand.

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Appendix A
Workshop Presentations

Appendix B
Background Information on Developing Climate Data

Appendix C
Forensic Analysis of Weather Related Power Outage Events

Appendix D
Risk Assessment Matrix

Appendix E
Risk Maps

Appendix F
Load Projection Methodology – Toronto Hydro

Appendix G
Engineering Analysis

Appendix H
PIEVC Worksheets

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Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

Application of the Public Infrastructure Engineering Vulnerability Assessment Protocol to Electrical Distribution Infrastructure

Final Report Appendices - Public

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Appendix A
Workshop Presentations

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Appendix B
Background Information on Developing Climate Data

Appendix B: Background Information for Developing Climate Data

B.1 Introduction

The following Appendix provides additional details about the methods used to develop the climate data used in the Toronto Hydro PIEVC Climate Change Risk Assessment. The development of climate data to support this study involved three main activities.

- Identify climate parameters (e.g. temperature, precipitation, wind) and threshold values at which infrastructure performance would be affected (i.e. climate hazards);
- Project the probability of occurrence of climate hazards for future climate; and,
- Convert projected probability of occurrence of future climate parameters into the seven point scoring scale employed by PIEVC studies to support the risk assessment.

This appendix provides more detailed information about the first two activities, namely the identification of relevant climate hazards and the estimation of their probability of occurrence in the future. The conversion of this probability information into PIEVC scores is not covered here, as it is already explained in the PIEVC Protocol V. 10.

B.2 Identification of Climate Parameters and Infrastructure Thresholds

In this study, the identification of relevant climate parameters and infrastructure impact thresholds (i.e. climate hazards) involved a combination of the three methods:

- Literature review;
- Practitioner consultation; and,
- Forensic analyses.

B.2.1 Literature Review

Design values in codes and standards generally provide an excellent "first guess" to determine infrastructure impact thresholds, providing information on not only baseline climatic design values, but on safety factors, load combinations, and so on. Codes and standards can also provide an understanding of changing thresholds depending on the age of infrastructure and therefore applicable code or standard. These values can also be used as a basis for discussion with practitioners, to determine if there are local modifications for in-field infrastructure. The occasional review and updating of codes and standards also tends to generate discussion and papers in the published literature, which can further provide background on why changes were made, how climatic data was processed, and when these changes became effective.

B.2.2 Practitioner Consultation

Discussion and consultation with practitioners is invaluable. Practitioners can describe important historical events and their impacts, relevant logistical and operational elements of the system, and new and emerging problems which may not be documented elsewhere. More generally, practitioners can provide guidance on where problematic interactions tend to arise and what can be done to reduce those impacts (i.e. adaptation measures).

This project included two workshops in which assumptions regarding climate elements and infrastructure breakdown were evaluated, discussed and modified. The first workshop played a significant role in re-evaluating climate elements which had been identified under Phase I. For example, in light of recent severe weather events **(see Appendix C)**, extreme rainfall and freezing rain were given somewhat higher priority under Phase II. Following a preliminary climate analysis, several thresholds were removed, modified, or refined at the second workshop, and the discussion of complex interactions confirmed findings from the forensic.

B.2.3 Forensic Analyses

Forensic analysis is the evaluation of past events through the application of scientific techniques and understanding to establish facts. It is meant to diagnose the causes of, and contributing factors to, a given infrastructure failure incident. These analyses can be used to refine our understanding of not only what caused a given failure, but also how to prevent or reduce the risks of similar failures in the future. In the context of extreme weather, we can evaluate the meteorological conditions associated with an incident and compare those to impacts produced (i.e. what was damaged, how was it damaged, etc.) and the supposed design capacity of that system (i.e. what was it designed for, do field conditions match design requirements).

Forensic analysis first requires the identification of important historical climatic events. In this case this was provided by Toronto Hydro's ITIS database, and further augmented by newspaper and press release searches. These events were then compared to all available observational data, including both Environment Canada's climate network and as well as data provided by TRCA (TRCA 2014) for several specific events. A full report containing analyses of several different events in the GTA is provided in **Appendix C**. These results were then compared to the literature and were also presented to practitioners for further scrutiny. Findings included the apparent impact of tree canopies on wind resistance of trees (resulting in subsequent secondary impacts on overhead systems), as well as regional differences in impacts from freezing rain, likely the result of a combination of local meteorological conditions (temperature regimes) and regional differences in canopy cover and tree health.

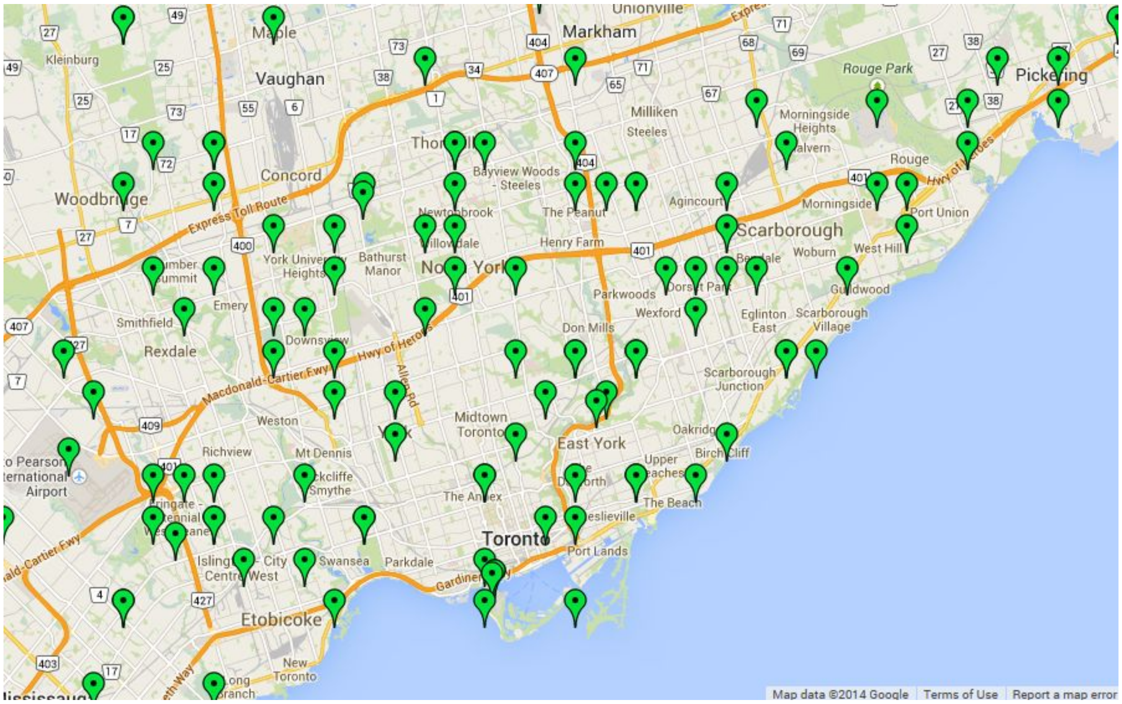
B.3 Establishing the Probability of Occurrence of Climate Hazards

The following section provides information necessary to project the future probability of occurrence of climate hazards. Information about the development of a historical climate baseline, the sourcing and use of future climate projection data, and the treatment of complex variables is presented.

B.3.1 Historical Climate Observations

Environment Canada is the authoritative source of climate information in Canada. In the Toronto region many observations stations have been in place and subsequently closed (see **Figure B.1**). In most cases stations only have observations for a few years – too short to establish a 'climatology'. The most recent normals period established by the World Meteorological Organization (WMO) was 1981-2010. Although 30 years is the accepted minimum, Environment Canada has calculated normals for stations which have at least 10 years of data within this period.

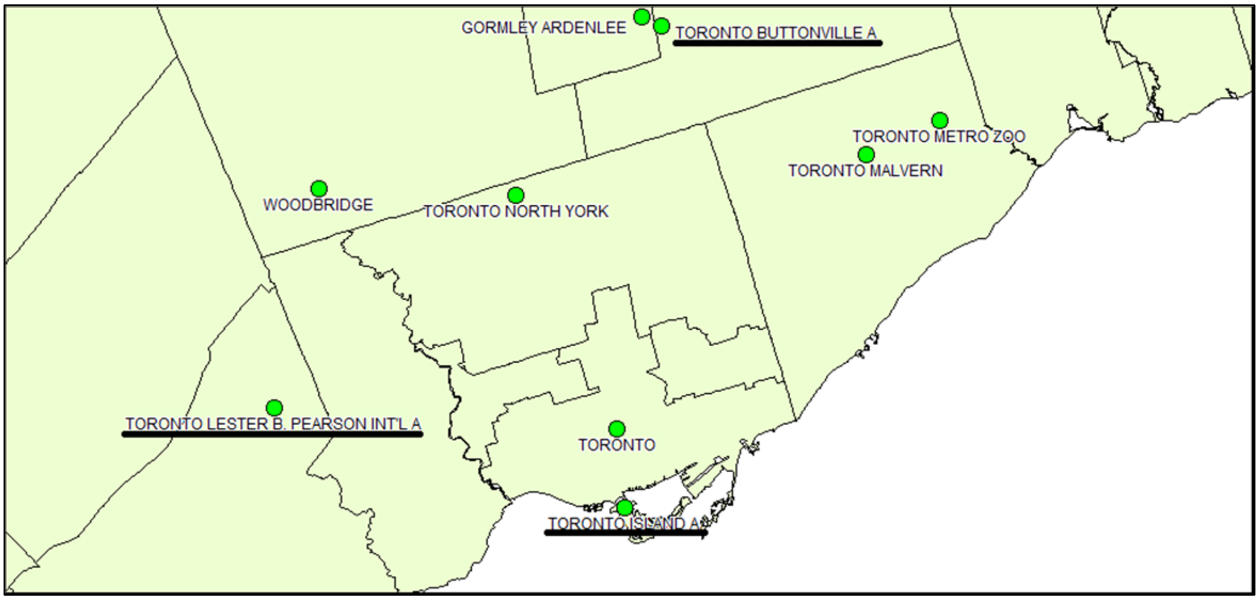
Figure B.1 All Historical Environment Canada Stations



Note: includes those not currently open

To establish reliable statistics on the frequency of events, long term records are preferred and with this area, there are some stations available. It is generally accepted that to establish a 'normal' climate, a minimum of 30 years of data as required. This supposedly ensures that short term natural variability is averaged out. Detailed hourly observations are usually only available at airport locations such as Toronto Pearson, Buttonville and Toronto Island. These airport locations are also typically the only source of variables other than temperature and precipitation (such as wind or weather observations). Of these, Toronto Pearson has the lengthiest reliable data record. Those regional stations for which normals data was calculated for 1981-2010 are shown in **Figure B.2**.

Figure B.2 Environment Canada 1981-2010 Normals Locations



Note: Stations with additional weather and wind data are underlined.

B.3.2 Future Projections

B.3.2.1 Global Climate Models

These variables will consider both the historical period frequencies observed in the region and the corresponding projections used in the most recent Intergovernmental Panel on Climate Change (IPCC)'s Fifth Assessment Report (AR5). The suite of models used in AR5 is from the Fifth Coupled Model Intercomparison Project (CMIP5), coordinated by the World Climate Research Program, and was retrieved from the following data portal:

http://cmip-pcmdi.llnl.gov/cmip5/guide_to_cmip5.html.

Since the second IPCC Assessment released in 1995, the number of contributing international climate modelling centres, models, and their complexity, have increased significantly – from 11 models to the current 40. With increased computing power, better refinement of atmospheric phenomena have been incorporated, and model spatial and temporal resolution has improved (Kharin et al. 2013). An important outcome of this increase in model availability is the ability to produce projections of future climate based upon an 'ensemble' of many models versus the use of single or only a few models. In this report, all available AR5 model runs (many models have more than a single projection available) were used. The use of multiple models to generate a 'best estimate' of climate change is preferred over a single model outcome. Research has indicated that the use of multi-model ensembles is preferable to the selection of a single or few individual models since each model can contain inherent biases and weaknesses (IPCC-TGICA, 2007, Tebaldi and Knutti, 2007). The use of the ensemble projection from the family of global modelling centers is likely the most reliable estimate of climate change projections on a large scale (Gleckler et al, 2008).

A full list of the climate models and their country of origin is presented in **Table B.1**.

Table B.1 List of CMIP5 Global Climate Models (GCMs) Used for this Study

Model Name	Organization	Country	Organization Details
ACCESS1-0	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
ACCESS1-3	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
BCC-CSM1-1	BCC	China	Beijing Climate Center, China Meteorological Administration
BCC-CSM1-1-M	BCC	China	Beijing Climate Center, China Meteorological Administration
BNU-ESM	GCESS	China	College of Global Change and Earth System Science, Beijing Normal University
CanESM2	CCCma	Canada	Canadian Centre for Climate Modelling and Analysis
CCSM4	NCAR	US	National Center for Atmospheric Research
CESM1-BGC	NSF-DOE-NCAR	US	National Science Foundation, Department of Energy, National Center for Atmospheric Research
CESM1-CAM5	NSF-DOE-NCAR	US	National Science Foundation, Department of Energy, National Center for Atmospheric Research
CMCC-CESM	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CMCC-CM	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CMCC-CMS	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CNRM-CM5	CNRM-CERFACS	France	Centre National de Recherches Meteorologiques / Centre Europeen de Recherche et Formation Avancees en Calcul Scientifique
CSIRO-Mk3-6-0	CSIRO-QCCCE	Australia	Commonwealth Scientific and Industrial Research Organisation in collaboration with the Queensland Climate Change Centre of Excellence
FGOALS-g2	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences
FGOALS-s2	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences
FIO-ESM	FIO	China	The First Institute of Oceanography, SOA, China
GFDL-CM3	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GFDL-ESM2G	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GFDL-ESM2M	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GISS-E2-H	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-H-CC	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-R	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-R-CC	NASA GISS	US	NASA Goddard Institute for Space Studies
HadCM3	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-AO	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-CC	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-ES	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
INMCM4	INM	Russia	Institute for Numerical Mathematics
IPSL-CM5A-LR	IPSL	France	Institut Pierre-Simon Laplace
IPSL-CM5A-MR	IPSL	France	Institut Pierre-Simon Laplace
IPSL-CM5B-LR	IPSL	France	Institut Pierre-Simon Laplace
MIROC-ESM	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere

Model Name	Organization	Country	Organization Details
			and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies
MIROC-ESM-CHEM	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies
MIROC4h	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MIROC5	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MPI-ESM-LR	MPI-M	Germany	Max Planck Institute for Meteorology (MPI-M)
MPI-ESM-MR	MPI-M	Germany	Max Planck Institute for Meteorology (MPI-M)
MRI-CGCM3	MRI	Japan	Meteorological Research Institute
NorESM1-M	NCC	Norway	Norwegian Climate Centre
NorESM1-ME	NCC	Norway	Norwegian Climate Centre

B.3.2.2 Representative Concentration Pathways

A new initiative in the IPCC AR5 is the introduction of RCPs (Representative Concentration Pathways; see **Figures B.3** and **B.4**). They represent a range of possible projection outcomes which depend upon different degrees of atmospheric warming. The lowest RCP 2.6, represents an increase of 2.6 W/m^2 to the system, while the highest RCP 8.5 represents an increase of 8.5 W/m^2 of energy. This range encompasses the best estimate of what is possible under a small perturbation situation (2.6) and under a large increase in warming (8.5). It is unknown which of the RCPs will apply in the future.   However, it is important to note that historically, the GHG emissions have followed the highest (8.5) pathway. In the absence of a global agreement on GHG reduction, this trend is expected to continue which would support this pathway going forward. Nevertheless, in this report, 4.5 (moderate) and 8.5 (high) projected change are presented. The number of models used for the ensemble varies with the RCP selected since not all international modelling centres generated model runs for all RCPs.

Figure B.3 Representative Concentration Pathways used for AR5

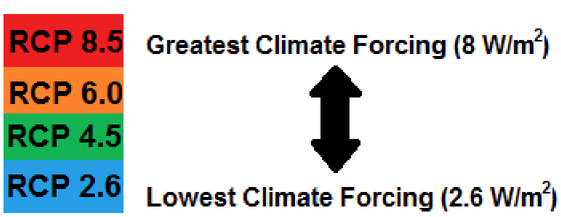
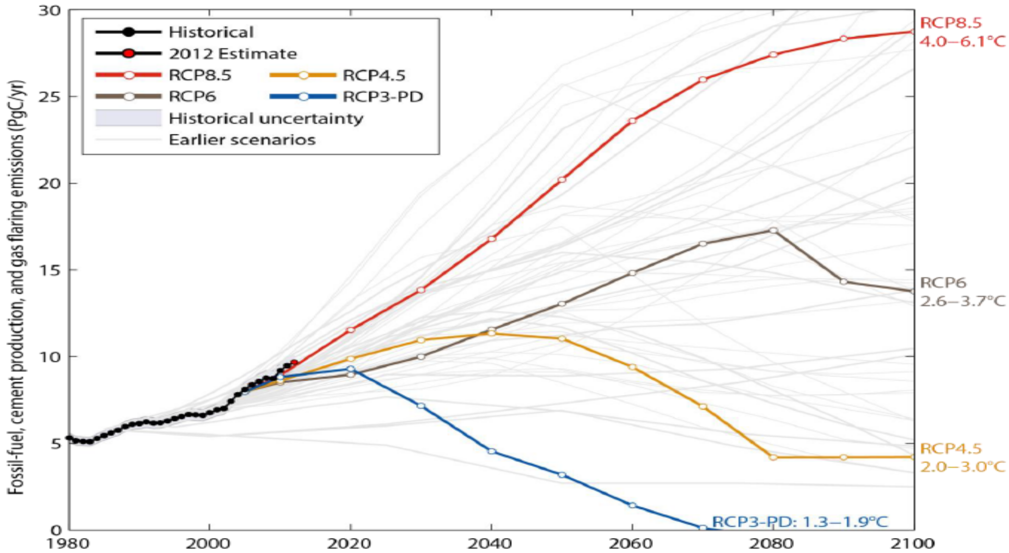


Figure B.4 Global GHG Emissions and their Relationship with Representative Concentration Pathway Assumptions



Source: Peters et al. 2012a

Factors influencing the RCP include population growth, economic growth, degree of urbanization, land use change, use of green versus carbon-based energy sources and any future international agreements on greenhouse gas (GHG) emissions, among others.

B.3.2.3 Important IPCC Findings

The full IPCC AR5 Working Group 1 Report was released in September 2013 and provides general details of the IPCC position on climate change. It can be found here: http://www.ipcc.ch/report/ar5/wg1/

Some of the main findings of this report are summarized in the Summary for Policymakers and are reproduced below:

- Warming of the climate system is **unequivocal**, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, sea level has risen, and the concentrations of greenhouse gases have increased.

- Each of the last three decades has been successively warmer at the Earth's surface than any preceding decade since 1850.

- Over the last two decades, the Greenland and Antarctic ice sheets have been losing mass, glaciers have continued to shrink almost worldwide, and Arctic sea ice and Northern Hemisphere spring snow cover have continued to decrease in extent.

- The atmospheric concentrations of carbon dioxide (CO2), methane, and nitrous oxide have increased to levels unprecedented in at least the last 800,000 years.

- Human influence on the climate system is clear. This is evident from the increasing greenhouse gas concentrations in the atmosphere, positive radiative forcing, observed warming, and understanding of the climate system.

- Human influence has been detected in warming of the atmosphere and the ocean, in changes in the global water cycle, in reductions in snow and ice, in global mean sea level rise, and in changes in some climate extremes. This evidence for human influence has grown since AR4. It is *extremely likely* that human influence has been the dominant cause of the observed warming since the mid-20th century.

- Observational and model studies of temperature change, climate feedbacks and changes in the Earth's energy budget together provide confidence in the magnitude of global warming in response to past and future forcing.

- Climate models have improved since the AR4. Models reproduce observed continental-scale surface temperature patterns and trends over many decades, including more rapid warming since the mid-20th century and cooling immediately following large volcanic eruptions.

- Global surface temperature change for the end of the 21st century is *likely* to exceed 1.5°C relative to 1850 to 1900 for all RCP scenarios except RCP2.6. It is *likely* to exceed 2°C for RCP6.0 and RCP8.5, and *more likely than not* to exceed 2°C for RCP4.5. Warming will continue beyond 2100 under all RCP scenarios except RCP2.6. Warming will continue to exhibit interannual-to-decadal variability and will not be regionally uniform.

- Changes in the global water cycle in response to the warming over the 21st century will not be uniform. The contrast in precipitation between wet and dry regions and between wet and dry seasons will increase, although there may be regional exceptions.

- Continued emissions of greenhouse gases will cause further warming and changes in all components of the climate system. Limiting climate change will require substantial and sustained reductions of greenhouse gas emissions.

With each subsequent report, the evidence of climate change builds and increasingly points towards greater confidence that human-kind is having and will continue to influence our future climate, from warming, to extreme events, to sea-level rise to melting sea-ice. Among the most recent IPCC reports was the addition of a separate document on climate extremes, the IPCC SREX document (SREX-IPCC, 2012). So in addition to changes in the mean climate, extreme climate events will also be impacted, and in many cases the changes in the extremes are expected to be greater than mean changes.

Of particular interest are some conclusions from the extremes report (SREX-IPCC, 2012):

- It is *virtually certain* that increases in the frequency and magnitude of warm daily temperature extremes and decreases in cold extremes will occur in the 21st century at the global scale.

- It is *very likely* that the length, frequency, and/or intensity of warm spells or heat waves will increase over most land areas

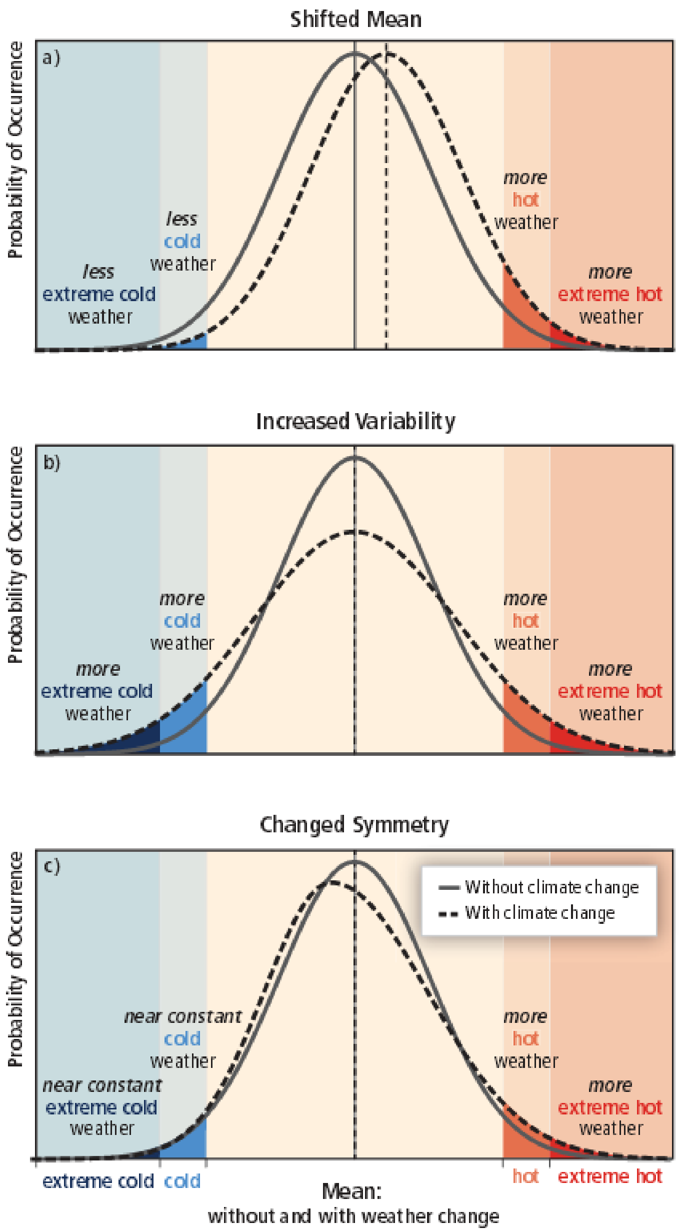
- It is likely that the frequency of heavy precipitation or the proportion of total rainfall from heavy falls will increase in the 21st century over many areas of the globe

- Extreme events will have greater impacts on sectors with closer links to climate, such as water, agriculture and food security, forestry, health, and tourism

- Attribution of single extreme events to anthropogenic climate change is challenging

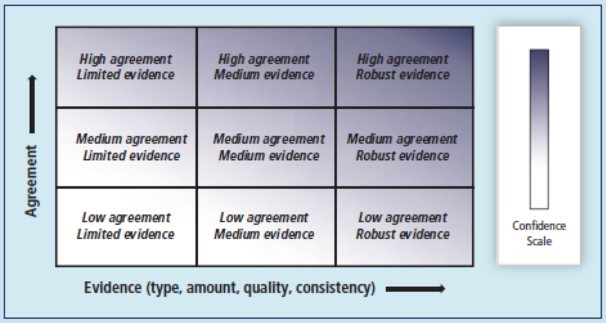
An example from the report is shown below for changes in temperature, which demonstrate how greater likelihood of extremes is possible through changes in mean, variability and symmetry.

Figure B.5 How Changes in Temperature Distributions can affect Extremes (IPCC, 2012)



Confidence wording in the IPCC documents are characterized by the use of specific terms such as 'very likely' or 'virtually certain', where in previous reports changes may have been referred to as 'likely'. There has been a gradual increase in confidence of the projections from climate models over time. A summary of the confidence terminology used in the official reports is shown below (SREX-IPCC, 2012):

Figure B.6 IPCC Confidence Terminology



A depiction of evidence and agreement statements and their relationship to confidence. Confidence increases toward the top-right corner as suggested by the increasing strength of shading. Generally, evidence is most robust when there are multiple, consistent independent lines of high-quality evidence.

The following terms indicate the assessed likelihood:

Term*	Likelihood of the Outcome
Virtually certain	99–100% probability
Very likely	90–100% probability
Likely	66–100% probability
About as likely as not	33–66% probability
Unlikely	0–33% probability
Very unlikely	0–10% probability
Exceptionally unlikely	0–1% probability

* Additional terms that were used in limited circumstances in the Fourth Assessment Report (*extremely likely:* 95–100% probability, *more likely than not:* >50–100% probability, and *extremely unlikely:* 0–5% probability) may also be used when appropriate.

With each report there are more and higher quality observations of the changing climate and improvements in the models equations/parameterizations, and their spatial and temporal detail. The IPCC reports continue to provide the best science-based information on projected climate change assembled from the best climate researchers worldwide. Climate change projections for this report are based upon the same new models used for guidance in the IPCC AR5 report recently released.

B.3.3 Climate Projection Methodology

B.3.3.1 The Delta-Method Applied to the Ensemble

The use of the CMIP5 ensemble not only allows for the calculation of an average projection of future climate which represents the consensus of all independent models, but it also allows for the estimation of projection uncertainty and statistical distributions which could not be determined from a single model. The projections for the variables in this report represent the 'best estimate' available – and are more indicative of the general expectations of climate change over any single model.

The ability of the CMIP5 ensemble to reproduce the historical temperature gives us confidence that the newest models used in this report are reliable and when grouped can provide accurate estimates. This would imply that reliable historical climatology should lead to reliable future projections.

This study uses a so-called 'delta' approach (sometimes also called 'climate change factor approach'), to obtain future estimates of climate variables. It is generally comprised of the following tasks.

1. Obtain a baseline climate condition (or 'average' climate).

2. Using an ensemble of all available CMIP5 models ('CMIP5 ensemble'), we obtain the model average climate for this same period – the average of all models for the grid covering Peel region. However, each modeling center does not use the same grid alignment and resolution, so a first step before obtaining the average of all the models is to regrid them all to a common resolution. This regridding typically uses a scale representative of the resolution of the models, in this case approximately 200 by 200 km.

3. The CMIP5 ensemble future climate is obtained for this same cell for each of the required future periods. In this case, every 10 years starting in the year 2011 and ending in the year 2100. From this we will have average future conditions of all the models for ten 10 year periods.

4. The difference (or 'delta') between the CMIP5 baseline and CMIP5 future periods are obtained – this represents the change in climate condition. Ten climate deltas are produced, for example, the delta between the baseline (1981-2010) and the 2051-2060 period is one of the deltas.

5. The final step is to then apply this delta value to the baseline period.

B.3.3.2 Complex Climate Events: Regional Climate Models and other projection techniques

The delta method applied to an ensemble of GCMs is not the only method available for climate change studies. Instead of using a delta ensemble approach, the delta approach could also be applied to single model, but the projection estimates would therefore only rely on ones assumption that the single model employed was the ideal choice. In climate science there are tradeoffs between model complexity and expediency.

It should be noted that many high impact atmospheric events tend to occur on much smaller spatial and temporal scales than are covered by GCMs (e.g. lightning, freezing rain, ice storms, tornadoes). Two main strategies have been developed to help address this, the use of regional climate models (RCM's) [1] and statistical downscaling studies. Both strategies were used in Phase 2 for several of the more localized and shorter duration climate elements analyzed. For one set of climate hazards (e.g extreme temperatures), the technique of employing a climate analogue was also used to validate the "delta-method" for determining these climate hazard probabilities.

Regional Climate Models

Another approach for obtaining specific climate projection information is to run a very high resolution model once over the area of interest (so called 'dynamical downscaling'). In the simplest of terms one can either have 'many model runs at a coarse resolution' or 'few model runs at high resolution'. These high resolution models are called 'Regional Climate Models' (RCMs). There are RCMs available, but this data can be difficult to obtain and they still require a coarser resolution CMIP5 or earlier model to act as a precursor. Over North America, the North American Regional Climate Change Assessment Program (NARCCAP) has assembled less than a dozen RCMs for various time periods (http://www.narccap.ucar.edu/). As these models have a high temporal and spatial resolution (i.e. hours and tens of kilometers), there are fewer RCMs available than the CMIP5 Global Climate Model collection. In addition there are far fewer model runs from which to obtain an average climate change value. For this study, the decision was to use many coarser models from which to obtain the climate change signal rather than fewer higher resolution models. However, some of the probability results for one set of climate hazards in Phase 2 (extreme temperatures) were generated using the CANRCM4 model, and a discussion of associated uncertainties can be found under the specific descriptions for those climate hazards found below.

Statistical Downscaling

Statistical downscaling studies attempt to solve the spatial challenges by developing statistical links between GCM scale climate conditions and localized, short duration events (e.g. freezing rain/ice accretion and wind gusts). Historical, point location climate data is compared with conditions on the scale of GCM grids. Statistical links, so called "transfer functions", are then developed based on these relationships. After GCM projections are developed for a given future period, these transfer functions are then used to "downscale" GCM projection back down to local scales. Although much less computationally intensive than RCMs, individual statistical downscaling studies still require significant expertise and time for proper execution.

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[1] These are sometimes referred to as "dynamical downscaling" methods, to provide an analogous term to alternative "statistical downscaling" methods.

The main drawback of this technique is that climate projections can then only be obtained from specific observation station locations which have sufficiently long data records. This method calibrates historical climate observed at an observation station (for example Toronto Pearson Airport), with historical model data at a coarse scale (called 'predictors'), to obtain a statistical relationship. For example, perhaps the daily temperature observed is related to the modeled upper atmosphere wind direction. If one provides the future upper atmosphere wind direction from a climate change model, it could then be used as one of the variables to predict the future temperature. The difficulty with this process even with pre-constructed software is that spurious associations based on pure statistics and not climatology can be applied which would produce unrealistic future conditions. Certainly some expertise in the statistical software is required. Additionally, this method requires specially formatted input statistical climate model data which is only available for a few models – and for few model runs and RCPs. This procedure would have to be repeated for all station locations for which there was long term reliable station observation data to produce estimates of climate change for only those specific locations.

An IPCC document entitled "Guidelines for Use of Climate Scenarios Developed from Statistical Downscaling Methods" (Wilby et al, 2004) further discusses these procedures.

Phase 2 made use of previously published statistical downscaling studies to support future climate change projections (Cheng, Li and Auld 2011, Cheng 2014).

Climate Analogues

In the case of extreme temperatures (i.e. average temperature over 30 and 35 C, extreme over 40C) climate change projections were also compared to a "climate analogue." Climate analogues refer to locations in other geographical areas which possess historical climates which resemble in many respects the future climate of the study area. The future temperature regime for the 2050's for the City of Toronto is very similar to the current and historical climate of northern Kentucky. While not an exact comparison – there are significant differences in regional geographical characteristics, for example – rough, "order of magnitude" comparisons can be made to help further determine if climate change projections are in fact realistic and represent potentially "real" climates.

B.4 Determining the Probability of Occurrence of Specific Climate Hazards

Based on the general methodology presented above, the probability of individual climate hazards were determined. The following sections describe in detail how they were estimated.

Extreme Temperatures

Temperatures and temperatures related indices are the most basic and reliable of climate elements, and therefore associated trends and projected changes to temperatures have the greatest confidence. Thresholds are based on previous consultation work from Phase I, IEEE standards for switching and transformer equipment, with some additional consideration from impact studies found in the literature - for example, see (McEvoy, Ahmed et Mullett 2012). The lowest thresholds generally address load forecasting and related factors, while higher temperatures begin to consider direct impacts to equipment.

Historical values were assessed using observations for Pearson Airport for the 1981-2010 normals period. Climate projections were then developed using the AR5 ensemble and RCP 8.5 emissions scenario. For temperature related thresholds which require information of *daily* temperature information, such as heat waves, 40°C maximum daily temperature, or the 35°C average daily threshold, required special treatment and were developed using projections from the CanRCM4 regional climate model (RCM), again using the RCP 8.5 scenario. The "Delta method" was then used to apply the modeled changes in frequency of those days applied to historical averages. It should also be noted that the range indicated for the 40°C threshold is the result of applying two methods, RCM and GCM based estimates, since RCMs are again potentially prone to overestimates due to numerical instability[2], while the GCM method may under-estimate the frequency of extremes due to averaging from large spatial scales. These results were further checked against climate analogues in northern Kentucky, again to serve as a consistency check against model projections to determine if these projected increases were realistic.

Extreme Daily Averaged and Maximum Temperatures

Manufacturers of electrical distribution equipment specify both maximum *one day average* and *peak ambient* temperatures for the operation of transformers and other components. With global warming, it is unsurprising that all thresholds show an increase in event frequency. High temperatures which already occur several times per year increase further in frequency, and a few extreme temperatures which are currently less than annual occurrences (e.g. daily average temperature of 30°C) are projected to become annual events.

The most striking results were noted with some of the highest temperature thresholds. For example, days with peak temperatures of 40°C or greater are extremely rare, with only one incident on record for Toronto's Downtown station[3], and *no* events reported at Pearson Airport during its entire period of record. However, indications are that these extreme heat days may become an annual or near-annual occurrence by the 2050's. Similarly, days with 24 hour *average* temperatures of 30°C or higher are also extremely rare but may become, on average, annual occurrences. However, as with the historical behaviour of lower threshold values, there will likely be some years with several days over the "new" threshold, while other years will have none.

Multi-Day Heat Events and "Warm" Nights

Other measures of extreme heat have been proposed as having a potential impact on electrical infrastructure.

While heat waves, defined as three or more days with maximum temperatures above 30°C, are currently slightly less than annual events, these are expected to increase in frequency to just over 1 per year, on average, into the 2030's and 2050's. The length of a given heat wave may also increase into the future. Regional climate model results suggest that for the 2030's, an average of approximately four (4) consecutive days over 30°C will occur every year, and by the 2050's the estimate is as high as *six* (6) consecutive days over 30°C per year.

So-called "warm nights" have also been implicated in excessive stress on electrical infrastructure (McEvoy, Ahmed et Mullett 2012) through increases in nighttime electrical customer use (i.e. need for continuous use of air conditioning systems), combined with an inability for equipment to sufficiently cool under warm nighttime ambient temperatures. These have increased substantially in recent years, with average of greater than one event per year in the most recent 15 year period of record at Pearson Airport. This includes a record of five (5) warm nights in 2005, as well as the warmest overnight temperature ever recorded in 2006 at 26.3°C. However, while the literature has indicated that the latter element may be important for combined impacts and stress to the electrical system, most workshop participants were indeed quite skeptical that warm nights were an important measure for electrical system impacts, indicating they considered extreme *daytime* temperatures and electrical use as the dominant cause for impacts to distribution systems, rather than warm nights.

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[2] Estimated increases in frequency from CanRCM4 were indeed so striking that they were checked against GCM based estimates for consistency. However, even when considering spatial and temporal averaging which will occur with the larger grid spacing and time steps inherent in GCMs, the ensemble still indicated significant increases in extreme heat days well beyond anything within historical experience.

[3] Three (3) consecutive days in July 1936 showed maximum temperatures reaching 40.6°C.

Spatial Geographical Variability

Mapping of extreme temperature days (**Appendix C**) indicate important temperature differences across the city, with temperature differences of 3-5 degrees between the shores of Lake Ontario and northern portions of the city. This is a direct result of the presence of Lake Ontario and its lake breeze, with cooler air from the lake keeping the shoreline and nearby areas cooler than parts of the city further north.

Extreme Short Duration Rainfall

The July 8, 2013 flash flood event in the GTA provided an example of the vulnerability of underground infrastructure to atmospheric events. While this particular case impacted Hydro One infrastructure, it is indicative of possible impacts to similar infrastructure owned and operated by Toronto Hydro. It was also an example of the importance and potential impacts generated by the loss of 3rd party infrastructure on which Toronto Hydro relies, emphasizing the interconnectedness of the electrical grid.

The threshold of "100 mm + antecedent" is based on rainfall accumulations estimated near the failure sites from the July 8th, 2013 event as well as other cases **(see Appendix C)**, although workshop participants felt this threshold might indeed be as low as 60 mm of rainfall. This threshold is in specific reference to high-intensity, localized rainfall events, characteristic of severe thunderstorms during the warm season. These generally last only a few hours in total, with the majority of that rain (over 50%) falling within a 1 hour time period. However, in every case, there was also antecedent rainfall in the preceding week which likely contributed to the overland flooding.

While these events are very difficult to predict even in short term forecasts, historical analyses on global precipitation extremes indicate that, in general, they will increase in intensity with climate change. However, the magnitude of this change, particularly for specific geographical regions, is not well understood (Kunkel, et al. 2013). Extreme, localized rainfall events represent an event type which cannot be modeled directly by GCM or even RCM output, and unfortunately no statistical downscaling studies for extreme thunderstorm rainfall exists for the GTA or nearby regions. However, global trends of historical increases in extreme rainfall are so significant that the climate team chose to increase annual probability score by one to account for this clear increase in thunderstorm extreme rainfall risk

Ice Storms and Freezing Rain Ice Accretions

Damage thresholds were also based on previous forensic work on freezing rain impacts, most notably Klaassen et al. (2003), as well as design requirements in codes and standards (CSA 2010a). These include thresholds for tree damage (15 mm) and for minimum CSA design (25 mm totals ≈ 0.5 inch radial). Freezing rain events represent an example of meteorologically complex events which require special treatment, and hence future projections presented here are based on tailored statistically downscaled results from published studies. Customized data specifically developed for Pearson International Airport were provided courtesy of C. Cheng (2011), using the same methodology employed in Cheng et al. (2011, 2014). Downscaled projections are expressed in *duration* rather than *accumulation amounts* due to the nature of the analysis methods used for downscaling. Climate projections of the parent large scale weather patterns (so-called "synoptic map typing") are based on the patterns and conditions which produce ice storms. For the downscaling work, these weather patterns were linked to the *duration* of freezing precipitation and not *amounts*, since total precipitation accumulation can vary significantly depending on available moisture. The duration threshold is also quite low (6 hours+) due to sample size, since storms of this magnitude or greater are infrequent.

However, these projections can be applied to other measures of ice storm severity given the following considerations:

1. Storms producing amounts on the order of 15 and 25 mm are of part of this "6 hour+" population, and we can therefore use results for the 6 hour+ storms as guidance for what will happen with 15 and 25 mm events; and,

2. Cheng et al. (2011, 2014) consistently showed greater increases in frequency for higher thresholds, hence storms with higher thresholds are expected to increase in frequency as much as or more than storms at lower thresholds;

Hence, changes in 6 hour+ event frequency are expressed as particular values, whereas the greater accumulation events are expressed as “greater than” some value.

Regional Differences in Severity

The severity of freezing rain events, specifically in terms of total ice accretion, tend to be lower for areas closest to Lake Ontario. In contrast to the summer, the lake acts to keep temperatures warmer during the early winter, an effect that appears to have been a factor during the December 2013 ice storm (see **Appendix C**). However, there are also indications from the forensic analyses that older portions of the city, particularly areas with a combination of significant, mature tree canopy cover and older overhead electrical distribution equipment, may be more sensitive to ice storms and are therefore more susceptible to smaller ice accretions.

It is very difficult to determine the return period or annual frequency of the extreme cases, since no events producing greater than 40 mm of total ice accretion have been reported in the GTA. The CSA standard for transmission line design (CSA 2010b) contains return period estimates for radial ice accretion for various locations[4]. Depending ones location within the City of Toronto, estimates for 30 mm ice accretion event (roughly 60 mm of total ice) indicate anywhere from a 1-in-150 to a 1-in-500 year return period event, termed “high” and “low” risk values, respectively, in table 3-2 in the main report. When increases in frequency of large ice storms is taken into account, these produce 35 year study period/”lifecycle” probability estimates of ~25% and ~8%, respectively[5]. However, these values are based on estimated return periods for extremely rare events, and the period of record on which they are based is far shorter than the return periods assigned to these ice accretion values.

Complexity of Freezing Rain Accretion versus Impacts

A myriad of measurements are given for freezing rain ice accretion due its complexity. Accumulations from airports, for example, represent *total* freezing rain amounts and not the thickness of accretions on overhead lines and structures, and hence certain freezing rain amounts can result in very different levels of ice accretion on infrastructure depending on numerous other factors (e.g. time, wind speeds, ambient temperatures). We also note that a significant majority of damage from the December 2013 ice storm was due to tree contacts at accretion thresholds lower than design requirements **(Appendix C)**, hence the inclusion of the 15 mm threshold.

High Winds

High winds can be produced by a variety of storm types and vary greatly in scale, intensity and duration. Design wind speeds found in codes and standards are based on large scale (synoptic) storms, while cases of extreme localized damage tend to occur with thunderstorm winds, including microbursts and tornadoes. This complexity introduces significant challenges when attempting to determine wind speed return periods for engineering design using historical data (Lombardo, Main et Simiu 2009), let alone the challenge of understanding how these might change under future climate conditions. Much like ice storms, wind gusts tend to also be affected by highly localized meteorological and geographical factors, and so meaningful projections cannot be directly extracted from GCMs or even RCMs.

[4] The values provided in the CSA standard (CSA 2010b) are themselves based on the Chaîné ice accretion model. These were felt to be accurate enough to provide estimates of extreme ice storms in the GTA for this study.
[5] Based on climate design table, highest risk locations are Etobicoke and North York, with the lowest risk is in Scarborough (CSA 2010a), the former not surprisingly representing areas which are slightly further away from the lake.

The 70 and 90 km/h thresholds are based on practitioner consultation from Phase I as well as forensic analyses conducted for Phase II (**Appendix C**). The highest threshold, 120 km/h, is based on IEEE design standards for switch gear and transformers, as well as other impact thresholds work, for example the EF-scale and McDonald and Mehta (2006). Climate change projections for the 70 and 90 km/h thresholds were obtained from statistically downscaled results in the published literature (Cheng, Li et Li, et al. 2012, Cheng 2014) using statistical downscaling methods similar to those used for freezing rain, while projections for 120 km/h threshold were not available.

The statistically downscaled results indicate increases for both thresholds analyzed here. Cheng et al. (2012, 2014) also indicated that increases in frequency of wind gusts were consistently greater as thresholds also increased (e.g. 80 km/h gusts increased more than 70 km/h gusts), but did not conduct analyses for thresholds greater than the 90 km/h due to small sample size.

Tornadoes

Tornadoes are small scale, isolated events, and hence the only available historical data are records of observations of their occurrence and/or resulting damage. Probability scores for EF1 and EF2 tornadoes were calculated based on historical records of occurrence within the City of Toronto from the most recently available 70 years of observational data. Historical data prior to this was deemed too unreliable to contribute to statistics in a meaningful fashion. This inconsistency also renders historical trend detection nearly impossible[6]. Their localized and complex nature also prevents the development of meaningful climate projections through any of the methods described here, including GCM or RCM output as well as statistical downscaling.

As with extreme temperatures, lightning and ice accretion, the northern portions of the city such as the North York and Rexdale (northern Etobicoke) areas exhibit a higher risk of tornadoes historically, again mainly due to the effects of the Lake Ontario lake breeze, but this does not exclude the occurrence of tornadoes in and around the downtown core.

Two different intensity levels were chosen due to important differences in their impacts. Research on historical events indicated that concrete utility poles and other more resilient infrastructure only fail in EF2 or stronger tornadoes, and hence these were investigated separately to determine relative risk.

High Impact/Low Probability Events: Probability Estimates and Their Interpretation

Tornado probabilities were subject to further analyses beyond those used for most other climate elements. Probability scores in Table 3-2 of the main report reflect the probability of occurrence for a *single point*; however, since these values are extremely small, a different statistical perspective was needed to better represent the type of risk posed by tornadoes. The City of Toronto has recorded five (5) F-2[7] tornadoes on two separate days since 1900, with a possible sixth case in 1976 in North York. Hence, over the 35 year life cycle study period, there is a 46% to 61% chance that a weather event producing one or more EF-2 tornadoes will strike somewhere within the City of Toronto. While the probability of a direct impact to a specific point or location is extremely small, the likelihood of a significant event *somewhere* in the city between 2015 and 2050 is in fact considerable, and could entail catastrophic impacts to a portion of the city's infrastructure.

Lightning

As with all other climate elements, lightning can vary significantly in intensity, with the same storm producing different lightning strikes with amperage values varying by several orders of magnitude. Even

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[6] However, some very recent work in the United States may finally be revealing changes in tornado climatology potentially associated with climate change in the form of increased *variability* in occurrence[6] (Brooks, Carbin et Marsh 2014).

[7] The so-called "Enhanced" Fujita, or EF-Scale, has only been used in Canada as the official replacement to the F-scale since 2013; however, the EF-scale is intended to be compatible with F-scale ratings in the historical record, and so references to tornadoes using the F-scale can, for the purposes of this report, simply be considered as storms of equivalent intensity.

for a single thunderstorm event, there now exists a great deal of data currently available for use in analyses and even forecasting of lightning occurrence, particularly following the establishment of the North American lightning detection network in the late 1990's, and more recent "total lightning" detection networks being installed in the GTA for meteorological monitoring for the upcoming 2015 PanAm games. It is suggested that Toronto Hydro investigate this data to better understand how lightning interacts with the electrical distribution system, such as investigation of significant lightning events (e.g. July 21 & 22, 2002) to determine why and how they generated so many impacts.

Investigation of New Probability Scoring Methodology

Lightning probability scores differ from Phase I due the changes in the method used to calculate probability values. The annual average frequency of cloud-to-ground lightning strikes varies across the city from under 1.12 to over 2.24 lightning strikes per square kilometer. The highest frequencies are seen in the northwest portions of the city, while the lowest are seen in southern Etobicoke (see Figure B-7). However, each individual strike will only affect a very small area. Hence, the probability of impact was estimated using representative "target sizes" (i.e. areas which represent the usual footprint of a given piece of infrastructure). A further assumption was tested assuming that lightning strikes would need to be within 25 meters of a piece of overhead infrastructure to produce negative impacts. The resulting probability scores were felt to be more representative of field conditions, particularly when considering the frequency of lightning impacts reported by Toronto Hydro (**see Appendix C**). These were also weighed against mounting evidence that lightning occurrence will increase in frequency with climate change, for example (Romps, et al. 2014), but by an uncertain amount[8].

Using two different "target" sizes provided by AECOM representing large (0.015 km^2) and small municipal (0.0001 km^2) transformer stations, probability of impact were calculated and compared, with and without the assumption of a 25 meter radius of impact. The results are provided in Table B-2 below.

Figure B-7 Lighting Distribution in Greater Toronto Area for 1999 – 2008 period, Lightning Strikes / /km^2•yr)

[8] Romps et al. (2014) indicated a potential increase of ~50% in total lightning strikes in the continental United States by the end of the century. However, while their methodology proved to be quite robust when compared to observational data, there was no assessment of GCM error in recreating the indices which drove this increase. Their index and model also appear to have difficulty with lake breeze related convection, which is of great importance for Toronto's lightning climatology. Hence, the RSI climate team chose to not apply these percentages as there remains too much uncertainty in how global climate change will impact lightning frequency in the Toronto area specifically.

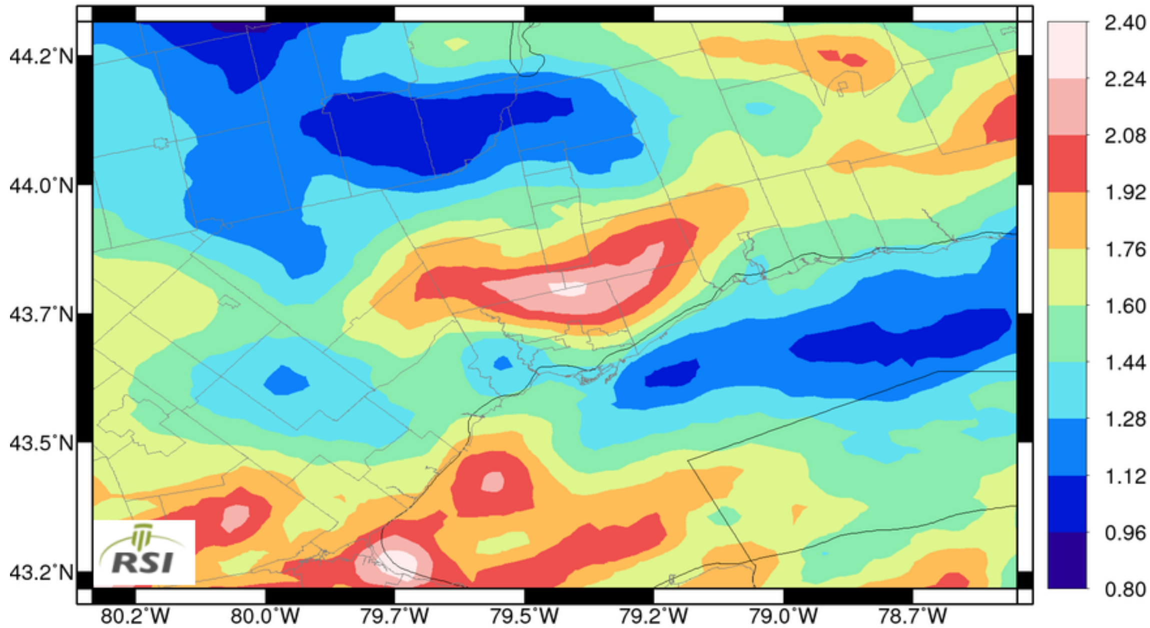
44.2°N
44.0°N
43.7°N
43.5°N
43.2°N
80.2°W
80.0°W
79.7°W
79.5°W
79.2°W
79.0°W
78.7°W
2.40
2.24
2.08
1.92
1.76
1.60
1.44
1.28
1.12
0.96
0.80

Table B.2 Lightning Strike Probabilities Transformer Stations

Target Type	Annual Lightning Frequency (km^{-2})	Annual Probability Score (2050's)	Study/"Lifecycle" Period Probability Score (2015-2050)
Large Transformer Station	1.12	1	5
Large Transformer Station	2.24	2	6
Municipal Transformer Station	1.12	0	2
Municipal Transformer Station	2.24	0	3

Snow

Snowfall thresholds were chosen following the second workshop and are intended to address "nuisance" events, such as those which require the application of deicing agents (5 cm+) and those leading to restricted to site access (10 cm+). The group chose to focus upon nuisance events at the "lower end" of the snowfall accumulation spectrum, rather than extreme snowfall events, since overhead systems were not considered by workshop participants as being sensitive to direct snow loading. Historical data indicate that the total number of days exceeding these thresholds are decreasing, as expected with global warming, but not at all rapidly enough to consider snow a "disappearing" hazard. In addition to this, and in contrast to days with small snowfall totals, days with extreme snowfall will continue to occur well into the future, and may in fact *increase* in intensity with further warming (Kunkel, et al. 2013). Hence, days in which snow will pose a hazard to infrastructure will continue well into the coming decades, even with continued warming.

Frost

Participants at the second workshop also indicated frost depth as being a concern for civil infrastructure, particularly following the extreme cold experienced during the 2013-14 winter season. As with other cool season hazards, the frost free period is expected to increase in length, which will result in less frost penetration on average, although occasional extremely cold winters will continue to occur well into the future. Frost depth calculations were not conducted for this project due to time and resource constraints, as well as significant variability associated with frost depth under the same atmospheric conditions. The latter is impacted by soil moisture, thermal conductivity, snow cover, and several other factors which vary greatly across the city. However, if frost heave is considered an important risk, further study could be conducted, using the 2013-2014 winter season as an example case study.

Complex Interactions

Complex interactions are generally defined as interactions which generate negative or unwanted impacts to infrastructure but which are the result of a *sequence* of events involving both climate and human factors. For the sake of simplicity, we have considered most climate elements in isolation. As the forensic analyses indicate, however, most real-world climate impacts are often attributed to one dominant element but with additional impacts from other simultaneously occurring hazards.

High Humidity Near-Zero Winter Environments

This complex interaction type was identified through both workshops and forensics work, and their occurrence appears to result from a *sequence* of events involving a combination of minor ice accretions followed by the application of de-icing agents. These are characterized by multi-day periods in which temperatures are near zero degrees, often "crossing" the zero degree line multiple times, and include multiple periods of freezing or frozen precipitation. Ice accretion may be from a combination of freezing rain, wet snow or rain-on-snow "re-freezing", with possible *additional* accretion from fog which is often present between periods of precipitation. These very moist conditions are then coupled with de-icing agents to cause short circuits, resulting in pole top fires and other incidents associated with short circuiting of insulators and switch gear.

Such a complex events entail the sequential occurrence of several meteorological factors coupled with human factors and are therefore impossible to project using the current set of climate change projection techniques. However, having identified these conditions, their occurrence could be monitored and even anticipated several days in advance using a combination of current conditions and short term weather forecasts, allowing for the mobilization of operational resources. The January 31st to February 3rd, 2003 event described in **Appendix C**, and a similar event which was identified for the transmission sector "sister" PIEVC study (January 2000) can be used to form the basis of pattern recognition for future events of a similar nature.

Tree Growth, Disease and Pests: Implications for Overhead Infrastructure

The second important complex interaction identified by our analysis entails the impacts of environmental changes affecting tree growth and health, affecting their resiliency to climatic loading. Higher average temperatures are expected to extend the growing season. This will likely result in faster tree growth and necessitate more spending on right-of-way maintenance, as well as possibly increasing tree vulnerability to wind and ice loading. The impacts of new and/or exacerbated disease and pest conditions can also increase tree vulnerability to damage, with the December 2013 ice storm and impacts on emerald ash borer infested trees being an example of this increased vulnerability. The complex interaction between accelerated growth rates, disease and pest regimes, and the resulting changes in vulnerability to adjacent infrastructure have only recently been identified and are not well understood, but should be subject to further study.

Appendix C
Forensic Analysis of Weather Related Power Outage Events

Brief Forensic Analyses of Weather Related Power Outage Events

C.1 Introduction

To better understand the nature and magnitude of climatic and meteorological events responsible for impacts to Toronto Hydro's electrical distribution system, as well as neighboring LDCs, RSI staff conducted forensic analyses of events generating significant impacts to the system. Information on the nature and extent of those impacts was compared to meteorological data to understand the nature and magnitude of atmospheric loads and conditions associated with these impacts. The analyses below consist of what can be termed either "single incident" or "cross-incident analyses," the former consisting of a "deep dive" into an individual events (listed in **Table C.1**), while the latter consists of the inter-comparison of numerous similar events to help determine commonalities.

In particular, events that were deemed meteorologically complex or multi-causal in nature, as well as meteorological events representing instances of impact thresholds, were selected for further assessment under "single incident" analysis to help refined our understanding of the thresholds at which impacts begin to occur, and what the causes and drivers of those impacts might be. Winter storms (including freezing rain events), summer thunderstorms, and a high heat case were evaluated for more detailed analyses. Other cases, such as fall season high winds, were evaluated under "cross-incident" analyses, for the purpose of evaluating and cross-checking thresholds determined from other sources (e.g. literature and practitioner interviews).

Several data sources were consulted for both meteorological and infrastructure impacts information. The former included data from Environment Canada's national climate data archive, Toronto Region Conservation Authority (2014) precipitation data, consultant reports (Cole Engineering 2013), as well as remote sensing data where appropriate. Impacts data were provided directly by Toronto Hydro, as well as outage incident press releases, newspaper accounts, and internal report (where available). Events which underwent detailed analyses are listed below in **Table C.1**.

C.1.1 Event Types and Relation to Impacts

Any number of climate and weather related events are capable of producing unwanted interactions with power distribution infrastructure. Direct impacts from severe winds, ice accretion, heavy/wet snow, extreme heat and lightning can directly overload support structures and conductors, as well as adjacent vegetation, which is also prone to failure, causing secondary impacts. Underground infrastructure is sensitive to flooding and longer term processes, such as enhanced corrosion through seepage and penetration of deicing agents. For each hazard, there are generally a small sub-set of mechanisms which can produce them. High winds during the warm season are associated with severe thunderstorms (including downbursts, microbursts and tornadoes), which tend to be intense but localized, whereas should season and winter severe winds are associated with large scale low pressure systems (so-called "synoptic lows"). Winds associated with these events are more widespread and can last for several hours to more than a day. Similarly, precipitation events are generally associated with thunderstorms during the warm season and low pressure systems in the cool season (snow storms, ice storms, etc.). It should become quickly apparent that several event types can occur simultaneously, resulting in multiple cause power outage events.

Identification of event type is critical in understanding what types of impacts to expect at different times of year, including duration of the event, potential challenges for response and maintenance, presence of simultaneously occurring hazards, and for some event types what antecedent conditions to monitor to help anticipate or forecast weather related impacts. During the late spring and summer, for example, a number of significant thunderstorm events tend to be proceeded by high temperature and humidity combinations which themselves may have generated impacts on the system. While individual events are indeed complex, infrastructure operators can begin to understand the antecedent conditions to help increase readiness for such events.

Event type identification is also critical to climatological analyses and the development of adaptation responses. More localized, short duration events present significant challenges for assessing future climate vulnerability and risk, but less complex climate elements, such as temperature, are far less difficult to analyze, and confidence in both the consistency of historical data as well as certainty in projected trends are much greater.

Adaptation responses, particularly those regarding maintenance and operations, must take into account the nature of the events generating impacts. How much lead time can one expect for storm warnings, if any? What hazards may be posed to repair crews, or restrict access to damage locations? For example, a number of recent press releases indicated that full repair efforts have been postponed based on the timing of high winds, with crews waiting for the “worst to pass” before executing major restoration efforts (see “Superstorm Sandy” analysis below). More sophisticated operations and management actions such as these are critical to optimizing response to severe weather events.

C.1.2 Brief Note on Impacts Data

Staff at Toronto Hydro kindly provided outage incident data for this analysis, which proved invaluable for determining the types and magnitude of events which were responsible for significant power outage events. However, this type of cross-disciplinary forensic analysis was not the original intent of the failure database, and as such there were a number of challenges which presented themselves when using the data.

Most notably, it became clear that data collection was inconsistent throughout the period of record. While the database contains events from the years 2000 to 2013 inclusive, earlier events have dozens of reports per date, while more recent major outage events do not. In 2013, the July 8th flood and December 21st-22nd ice storm, which Toronto Hydro staff indicated were among the worst in their history, have very few listings in the database. This is likely due to changes in reporting practices, which apparently began in 2007 judging from the frequency of weather events with 20+ reports each, but this requires confirmation Toronto Hydro staff.

This emphasizes the need for the standard forensic practice of consulting and comparing multiple sources of data. For example, impacts data can be used to indicate if event intensity, such as high winds, could have been significantly higher than meteorological measurements may indicate. Conversely, meteorological data can be used to either guide and/or refine the search for impacts data, or even correct coding or other errors in impacts data.

C.2 Toronto Hydro Outage Data

As indicated above, outage data from Toronto Hydro were interrogated to identify significant outage events which could be used for further study. Days with 20 or more reports were identified, and these were further refined by checking for potentially related reports on days before and after identified event dates. While it is fairly clear that data from 2007 to 2013 were collected under different reporting requirements, 2000-2006 appear to be consistent, and so data for this period will be evaluated here.

A total of 46 weather events were identified with this methodology. Just over half (54%) of these events occurred over fairly extended periods of 12 to 48 hours; this has implications for maintenance and repair response measures. For fall wind storms and winter precipitation events, this quite literally meant several consecutive hours of either high winds or precipitation generating impacts, while for summer events this likely represents two or more episodes of thunderstorm activity within a one to two day period.

C.2.1 "Worst" Years

In terms of the "worst" years, we have two measures; total number of events, total number of damage reports for these events, and number of damage reports per event. The years 2000 and 2005 are tied for the most events in a given year (9). In terms of total reports for all events combined, 2000 has the highest at 6—followed by 2003. In terms of average event severity, the total number of reports was divided by the number of events in a given year as a rough measure of "average" severity for a given year. The year 2003 had the highest average, with an average of just over 84 reports per event. Even though 2000 and 2005 contain single major events, their averages fall well below those seen in 2003, 69 and 56 reports per event respectively.

The year 2000 followed two main themes. A series of severe winter storms in February were responsible for multiple reports and were characterized by either freezing rain or heavy wet snow and rainfall combinations, both characteristic of "warm" winter storms producing heavy precipitation at temperatures near or at 0°C[1]. This was followed by late spring to summer severe thunderstorm events, including the May 12-13, 2000 event, as well as a thunderstorm event on July 14, 2000, which generated over 100 reports through mainly lightning related damage.

The year 2005 was characterized by high heat and humidity during the summer months, which either directly contributed to infrastructure underperformance as well as severe thunderstorm events, most

[1] At temperatures at or just below freezing, atmospheric water content is at its highest while still being able to support ice formation; hence temperatures near zero are associated with either freezing rain or high density, wet snow capable of physically coating and loading overhead lines and trees.

notably the August 19th, 2005 storm. This was followed in the fall by a series of wind storms which produced scattered outages throughout the GTA, which was among several areas across Ontario which were impacted by intense fall windstorms (e.g. over 100,000 Hydro One customers lost power during the November 6, 2005 synoptic storm; Hydro One 2005).

Finally, in 2003, Toronto Hydro was impacted by a similar combination of event types, with two winter storms in rapid succession in February, followed by severe thunderstorm activity during the late spring and summer, followed by large scale wind events from late September to mid-November.

All of the so-called "worst" years identified here have the following in common:

- Repeated events, often with only days between similar types of incidents
- Two or three "modes" of high impact weather events in the same year, specifically:
    - "warm" winter storms, meaning they were associated with temperatures at or just below 0°C with some combination of heavy snow, freezing rain or even rainfall mid-winter;
    - Severe thunderstorms and high heat and humidity during the summer;
    - Multiple fall season large scale (synoptic) wind storms;
- One major event which produced over 150 damage reports

These findings can help with better planning and anticipation of particularly high impact years. For example, periods of very high heat and humidity should be watched closely, as they are occasionally followed by severe thunderstorm events when the heat "breaks" with the passage of a cold front or other air mass change. Fall and spring large scale wind storms will occasionally occur in series, as occurred between September 29th and November 13th 2005[2], repeatedly impacting the same area. These findings appear to be consistent with recent experiences; in 2013, Toronto Hydro suffered two major weather related outage events, one in the summer from a severe thunderstorm event producing extreme rainfall, followed in the winter by a freezing rain event.

It may also be possible to anticipate a particularly severe damage year since the "major" events producing over 150 reports tend not to occur in isolation but usually occur in years with a number of less severe but still significant events, although the consistency of this pattern requires further research.

C.2.2 "Worst" Events for 2000 to 2006 Period

The two events with the greatest number of reports, May 12-13, 2000 and August 19, 2005, were both subject to detailed analyses. Another three events (Jan 31-February 4, 2003; July 14, 2000 and July 21-22, 2002) produced over 100 reports, with September 19, 2003 coming very close at 99 reports.

What is of particular interest is the number of severe thunderstorm related reports which were accompanied by mainly lightning related outages. Even for storms which included extreme rainfall and high winds related impacts, lightning appeared to be the dominant factor in producing outages. The July

[2] A fourth synoptic storm occurred on November 15 to 16, 2005 but did not cause significant impacts to Toronto Hydro's infrastructure, instead tracking to the north east and affecting Georgian Bay and the "Nickel Belt," causing over 50,000 Hydro One customers to lose power.

21-22, 2002 event is particularly noteworthy. Although we do not have detailed lightning information, such information is available from the national lightning detection network, and the frequency and amperage of lightning experienced during this thunderstorm series could be investigated to determine what made this particular lightning storm so damaging to the system in comparison to any number of other events. A summary of all events identified through this method is provided in **Table C.2**.

C.3 Fall and Winter Storms

C.3.1 December 20-22, 2013 Ice Storm

The December 2013 ice storm in south central Ontario has been deemed the worst ice storm in Toronto Hydro's history in terms of impacts to the city's distribution system. It is estimated that at the peak of event during the overnight hours between December 21st and 22nd, ~300,000 customers were without power. The most recent estimates of total damage incurred by Toronto Hydro's distribution system has been placed at nearly $15 million, specifically for restoration and repair (Toronto Star: March 31, 2014).

The storm also impacted several other adjacent LDC's, including:

- Enersource (Mississauga), 91,000 customers affected (Mississauga.ca 2014);
- Hydro One Brampton, 15,500 customers (Brampton Guardian, Dec 30, 2013);
- PowerStream (York Region[3]) 92,000 customers (Markham Economist and Sun, December 31, 2013);
- Veridian (Pickering/Ajax/Port Hope) 40,000 (Veridan Connections Press Release, Dec 22, 2013);
- Whitby 13,000 (Oshawa This Week, Dec 22, 2013)
- Oshawa Public Utilities Company ~30,000; and,
- Rural areas of Clarington (Hydro One) ~46,000 (Ajax News Adviser, Dec 23, 2013)

Meteorological data from both Environment Canada and Toronto Region Conservation Authority stations were analyzed to estimated ice accretion totals and rates in and around the GTA, which were then compared to impacts on electrical distribution infrastructure in the area.

C.3.1.1 Impacts and Meteorological Conditions: City of Toronto

Figure C.1 compares estimated ice accretion values at Pearson and Buttonville Airports with the total number of customers affected reported by Toronto Hydro. While ice accretion values were not directly reported by any of the stations evaluated, they can be estimated by combining hourly observations of precipitation type with daily rainfall totals. Freezing rainfall and drizzle totals were estimated by first determining the fraction of precipitation falling as freezing rain or drizzle (since liquid rainfall and snow were also reported on some days). Accretion rates were then weighted by precipitation type (1 for rain, 0.5 for moderate rain, and 0.1 for drizzle, based relative accretion rates from Klaassen et al. 2003), which were then further developed into estimated hourly average accretion rates. These were then summed for each day between December 20th and December 23rd for both Pearson Airport and

[3] PowerStream also suffered the complete outage of their website, which had not been designed to receive the traffic volumes which it encountered during the event (Markham Economist and Sun, December 31, 2013).

Buttonville Airports, the only locations near the City of Toronto for which hourly observations of precipitation type were available. Given that several locations experienced both above zero temperatures and liquid precipitation during the multi-day period under analysis, and that ice accretion on overhead structures, lines and trees is further affected by wire or branch diameter and surface characteristic, it is likely that estimated multi-day ice accretion estimates are *over*-estimates of true accretion values. This will be taken into account during the discussion of impacts.

Ice accretion totals for the 3 day period are over 30 mm for Pearson Airport and nearly 35 mm at Buttonville. A review of hourly temperatures at both airport for the same time period (not shown) also indicate that Pearson Airport was above zero for several hours longer than Buttonville, implying that less freezing precipitation accretions may have been retained there than at Buttonville. A comparison of photographs taken following the storm, both of ice accretions on different objects, as well as the apparent severity of tree damage to areas near the two airports provide evidence that ice accretions immediately north of the City of Toronto incurred ice accretion amounts several millimeters greater than those experiences in northern portions of the city (**Figure C.2**).

The relative impacts of temperature regimes become readily apparent, however, when ice accretion estimates are isolated to include only freezing rain totals beginning late morning on December 21st, excluding accretion contributions from the December 20th to 21st overnight precipitation episode. Ice accretion values become only 13 mm for Buttonville and *25* mm for Pearson. This implies to important elements for understanding how ice accretion values evolved in different portions of the GTA, particularly:

- Higher than 13mm ice accretion values for municipalities north of Toronto cannot be explained without including precipitation amounts from the earlier December 20th-21st episode;
- Lower than 25 mm ice accretion values near Pearson Airport likely cannot be explained without considering periods of >0°C temperatures, combined with the effects of liquid (non-freezing) rain and drizzle

Estimate ice accretion values on the order of ~20 mm were present when outages began, with amounts of 18 and 23 mm at Pearson and Buttonville respectively just prior to first report of 8,500 outages. Press releases indicate that this initial damage was indeed focused in northern and northeastern portions of the city (Toronto Hydro Press Release; December 21, 11:58 PM); accretion values estimated from these airports are likely representative of those experienced in the first areas suffering from widespread power outages. Rounding down to allow for some ice accretion losses due previously discussed factors, a range of 15-20 mm are likely responsible.

To better understand conditions in and near the downtown core versus surrounding portions of the city, hourly temperatures at the Downtown meteorological station (located at the University of Toronto campus on Bloor Street) and Toronto Island's Billy Bishop airport, were compared to those at Pearson Airport (**Figure C.3**). Radar imagery (**Figure C.4**) indicates that precipitation elements were moving very rapidly (over 100 km/h) during the freezing rain event, hence hourly precipitation reports at Pearson Airport are likely representative of the occurrence or non-occurrence of precipitation conditions at stations located less than 20 km to the ESE, where manned observations of precipitation type are not available. Precipitation reports from Pearson Airport were therefore superimposed on temperature plots to indicate when precipitation was occurring, and more importantly to imply whether or not precipitation was falling as liquid rain or freezing rain for downtown locations for a given hour.

Figure C.4 shows hourly temperatures at the three Toronto locations, implying that the city's downtown core likely received much less freezing rain than surrounding areas (the so-called "horseshoe" of former suburbs), and that accretions from December 20th and most of December 21st would have been unable to remain on exposed surfaces. However, a period of particularly heavy precipitation overnight between December 21st and 22nd correspond with temperatures below freezing, with both downtown stations falling below 0°C between 10 and 11 PM on the night of the 21st.

Toronto Island Airport reported 17.7 mm on December 21st and 13.9 mm on December 22 and the Downtown station reported 17.0 mm and 14.3 mm, respectively. Assuming the majority of precipitation on December 22nd fell as freezing rain, with some additional contributions from precipitation late in the evening on December 21st, ice accretion values in the downtown core were likely on the order of ~15 mm, compared to estimated values in excess of 25-30 mm or more estimated for northern portions of the city and adjacent municipalities. The implication, however, is that severely impacted portions of the city of Toronto near the downtown core may have seen significantly smaller ice accretion values than other parts of the city but still suffered from multi-day power outages.

Estimates of ice accretion rates at Pearson and Buttonville airports, along with the severity of impacts in the downtown core, which likely only saw ~15 mm, suggest that the final hours of the freezing rain event produced much more rapid ice accretion rates than earlier phases. Between 11 PM December 21st (when downtown stations were below 0°C) and 9AM the following morning, only 7 hours of freezing rain was observed at Pearson Airport. Even with significant averaging inherent in ice accretion rate estimates calculated in **Figure C.1** for Pearson and Buttonville airports, freezing rain ice accretion rates peaked during the early morning hours of December 22nd, estimated at 2.13 mm/h at Pearson and 1.25 mm/h at Buttonville, compared to estimated hourly rates on preceding days (0.79 and 0.95 mm/h for Pearson; 0.92 and 1.19 mm/h for Buttonville). A review of radar imagery for that time period (**Figure C.3**) indicates that a particularly heavy area of precipitation, associated with a small scale meteorological feature, tracked over the GTA and surrounding areas in the early morning hours of December 22nd. This corresponded with the rapid increase and peak in reported outages, and was likely responsible for a large portion, if not the majority, of ice accretions experienced in and around the downtown core.

Immediately following the ice storm, one spokesperson for Toronto Hydro indicated the worst damage appeared to be following highway 401, but this was prior to knowing full extent of damage in Scarborough (Toronto Star; December 23, 2013). Outage maps of the city the following day showed a clear delineation of much less severe impacts south of Bloor Street versus areas north and east of the downtown core, however a lack of both detailed impacts data and/or meteorological observations, particularly for Scarborough and East York, complicate better diagnoses of the reasons for these differences. At these scales, there could be a complex interplay between local topography, infrastructure characteristics, tree canopy extent and/or health, as well as small scale meteorological elements (e.g. there may have been marked small scale differences in temperature gradients or locally enhanced precipitation). Without higher resolution data, all potential causes for these boundaries remain speculative.

C.3.1.2 Impacts and Atmospheric Conditions: Durham Region LDCs

Analyses of impacts to LDC's east of the city of Toronto are complicated by a lack of both detailed impacts information as well as aforementioned meteorological observation data. Only daily precipitation totals and hourly temperature data are available for Oshawa Airport, and only a small number of TRCA stations were available to provide temperature data for the Ajax and Pickering areas, but did feature high sampling rates (5 and 15 minute intervals). However, given the characteristics of damage reported by the press, it can be easily surmised that a significant amount of ice accretion occurred in the region.

A review of hourly temperature data for Oshawa Airport indicate that for the 72 hour period beginning at 4 PM on December 20th, there were only ~4 hours in which temperatures were at or just slightly above 0°C, specifically between 11 PM December 22nd and 2 AM December 23rd. This suggests that the majority of the precipitation on December 21st and 22nd, with daily totals of 17.6 mm and 10.3 mm, respectively, was likely freezing rain. Accretions could have also included some of the 8.1 mm reported on December 20th, where temperatures remained below 0°C after 4 PM. Similarly, temperature data from a TRCA weather station at Bayly and Church in Ajax (**Figure C.6**) indicate ~3.5 hours mid-day on December 21st, for which temperatures were above 0°C for the same time period, as do temperature data for the Brock West Landfill site, north of Pickering, for ~3.3 hours (TRCA 2014). The overnight temperature spike indicated at Oshawa Airport on December 21st and 22nd also shows up clearly for these two stations, but remains *below* freezing. Temperatures remained below 0.5°C for all three sites, even with sampling rates of 15 and 5 minutes for the two TRCA sites. Hence, when considering temperature conditions associated with the event, freezing rainfall totals in the ~25-35 mm range are likely for portions of southern Durham region.

Restoration times were checked in local newspapers and available press releases from LDCs (mainly Veridian) to ascertain how quickly Durham region LDCs recovered from the event when compared to Toronto Hydro. A rough benchmark of 90% restoration was used to compare the LDCs and using the morning of December 22nd as a start time for full restoration efforts:

- Veridian (Ajax, Bowmanville, Newcastle, Port Hope), restored by 8 PM December 24th, 2.5 days;
- Oshawa PUC, restored mid-day December 23rd, ~1 day;
- Whitby Hydro, fully restored by December 24th, 1-2 days;

These are compared to Toronto Hydro, which required more than **5** days to restore power to 90% of customers affected by the event. The effects of scale on Toronto Hydro's distribution system, as well as increased vulnerability from aged infrastructure, aged trees adjacent to overhead lines, and difficulty servicing and accessing equipment cannot be underestimated. There are also likely differences in the ratio of response capacity (e.g. number of personnel versus number of customers) as well as shear geographical area to be covered. Significant differences in recovery time appear to be an excellent example of how logistical challenges for larger metropolitan LDCs can result in marked difference in vulnerability when compared to much smaller LDCs servicing small cities and rural areas, in spite of the fact that Durham Region appears to have, on average, been impacted by similar to possibly higher ice accretions than large portions of the City of Toronto. Overall, at least in the case of the December 2013 ice storm, larger LDCs appear to be more susceptible to ice storms than smaller ones, likely due to a combination of factors.

Veridian indicated that by noon on December 26th, only ~1,700 of the original 40,000 customers who had lost power remained without service (DurhamRegion.com, Dec 27, 2013), and that these mainly consisted of particularly difficult to repair elements, such as backyard supply lines. Similar comments were made by Toronto Hydro staff regarding back-lots which needed to be serviced and which were quite common in some parts of the city, although indications are that these will be eventually phased out.

Tree impacts were again named explicitly as the cause of much of the damage in Durham Region (Ajax News Adviser; December 23, 2013). On December 26th, Oshawa PUC continued to report problems with tree branches falling on lines generating new damage, and on the same day a statement by utilities officials in Whitby indicated that recent snowfalls had added more weight to ice covered tree limbs, and warned of an increasing the risk of breakage and the potential for new damage (Durham Region.com, December 26, 2013). These concerns are again similar to those expressed by Toronto Hydro and indicate an aspect of ice storm damage which should be considered in response and recovery methods.

C.3.1.3 Case Specific Findings December '13 Ice Storm:

While ice accretion values likely approached or even slightly exceeded minimum CSA design requirements (CSA 2010) for overhead systems for small portions of the city of Toronto, Durham Region, and other areas, it appears that the vast majority of damage inflicted on overhead distribution lines during the ice storm was due to the impacts from falling tree limbs. Immediately following the ice storm, tree damage was indicated as "worse than originally anticipated" (TH Press Release, Dec 23, 2014, 3 PM) in spite of what has since been termed aggressive tree trimming programs in place prior to this event. At least two municipalities, Brampton and Whitby, also indicated concerns that emerald ash borer (EAB) affected trees posed particular risks due to their weakened state. Tree impact damage continued for several hours to several days after significant ice accretion ceased. One line worker described how falling tree limbs continued to damage lines even during maintenance, and that repairs had to be redone at some locations (Toronto Star: December 23, 2013). This is also consistent with continued tree fall observed by one of the authors (S. Eng) during the mid and late-afternoon of December 22nd in central Etobicoke area, again several hours after significant ice accretions had ceased.

It is hypothesized that continued damage may have been due to both continued light freezing and frozen precipitation which continued periodically at various locations through December 22nd and 23rd, and gradual loss of fiber strength from prolonged loading.

During the recovery effort, there were notable. increases in estimated restoration times as efforts progressed. Estimates in earlier press releases indicated restoration times of 12-16 hours were expected, while *eventual* restoration times, particularly for the remaining 10% of customers to be restored, were in excess of 5 days.

Total ice accretion amounts for areas surrounding the City of Toronto were likely much higher than those experienced in the downtown core and surrounding areas. In areas within Durham and York Regions, temperatures generally remained cold enough to maintain freezing rain ice accretions which began as early as the afternoon of December 20th. As one approached the downtown core of the City of Toronto, the event transitioned to one better characterized as a relatively short duration but fairly intense period of freezing rain, the majority of ice accretions and impacts occurring during the overnight and early morning hours between December 21st and 22nd, rather than multi-day ice accretions apparent in areas surrounding the city. These characteristics of the freezing rain event need to be understood when considering differences in both impacts and vulnerability of Toronto Hydro's distribution network when compared to LDCs in adjacent municipalities.

Press releases in the days following the event placed a clear emphasis on electrical stand pipe damage to individual homes in Toronto Hydro press releases. It is hypothesized that, as ice accretion amounts increase, more and more elements of the electrical system are damaged, hence repairs become exponentially more difficult to execute, as impacts progress from isolated large branches on lines to entire trees, and as a higher percentage of individual residences suffer damage, as indicated by the widespread damage to individual residential standpipes suffered in the Toronto Area. Similar impacts were noted during the January 1998 ice storm in Quebec, where all not only transmission corridors were severely damaged, but also individual residential lines, making recovery especially challenging due to numerous repairs on the individual customer level.

A lack of manned observations of precipitation type south and east of Pearson Airport was found to be frustrating to the investigation, particularly for **Toronto City Center** and **Island Airport** stations as well as **Oshawa Airport**. While useful findings were developed based on precipitation estimates and proxy analyses (e.g. use of temperatures to imply precipitation type), manned observations confirming precipitation type and accumulation rates would greatly assist with diagnoses of conditions in downtown Toronto as well as for Durham Region LDCs. Impacts data in the form of outage timelines and descriptions of damage could then be combined with more representative meteorological data to compare relative sensitivities of adjacent LDCs to ice storm conditions. A lack of any meteorological observations for East York and Scarborough were particularly frustrating, given apparent (and as of yet unexplained) boundaries in impact severity for these portions of the city.

Similar problems were encountered with TRCA data. While some locations provide precipitation data during the winter, all were well north and west of both Toronto's downtown core, as well as populations centers in Durham Region impacted by the storm. This indicates the need for improved monitoring of winter precipitation in populated areas of the GTA, since differences in impact severity between different municipalities is difficult without detailed observational data on precipitation characteristics.

A significant meteorological component of the event, especially for areas in and around Toronto's downtown core, appears to have been a particularly heavy episode of precipitation during the early morning hours of December 22nd associated with a small scale meteorological feature. This implies that for high impact winter events, even those associated with large scale processes, difficult to forecast smaller scale[4] meteorological phenomenon, perhaps only a few dozen kilometers in physical extent and affecting a given location for only a few hours, may still play an important role in generating impacts. This emphasizes the need for continued monitoring of weather forecasts and meteorological remote sensing data such as radar, since the onset of impacts from these types of phenomenon can be quite rapid and are akin to severe thunderstorm events during the warm season.

In addition to Toronto Hydro, several other LDCs also indicated marked differences in the severity and extent of impacts within individual municipalities. Enersource outage maps, for example, showed particularly severe impacts in the northwestern portion of Mississauga. Veridian indicated that southeastern portions of Ajax suffered more damage and were more difficult to restore, mainly due to aged trees characteristic of the area (Ajax News Adviser; Dec 23, 2013), and similar reports of particularly heavily affected areas were also noted for Pickering (DurhamRegion.com; Dec 24, 2014), although a specific cause for these difficulties was not given. More detailed studies of these localized disparities in impacts would be extremely informative. These would likely consist of surveys and could include a review of individual incident reports and the collection of visual materials, as well as an assessment of contributing factors such as tree species and canopy cover maps, infrastructure age and characteristics, and so on.

C.3.2 Other Winter Storms

For comparison to the December 2013 event, other ice storms were reviewed to determine if thresholds from previous research (Klaassen et al. 2003) were directly applicable to the City of Toronto and to also determine the severity of impacts from less severe and widespread storms. Klaassen et al. (2003) indicated that ice storms with as little as 15 mm of total ice accumulation have resulted in widespread power outages, mainly due to tree limb impacts, and while this agrees well with analyses from the December 2013 storm, other events should also be interrogated.

C.3.2.1 January 31st to February 4th, 2003: Complex Winter Event

The period between January 31st and February 4th, 2003 saw multiple types of precipitation and a variety of conditions impacting the Toronto Hydro distribution system, and resulted in over 50,000 customers being affected at various time by power outages (ITIS data). Some 160 incidents were reported in the ITIS database beginning on the evening of January 31st through to February 4th, including blown transformers and current limiting fuses, tracking problems, and some instances of galloping and tree contacts. On the night of February 3, 2003, "hundreds" of car accidents and numerous power outages were blamed on a combination of freezing rain and high winds, mainly across Scarborough and North York (Toronto Star, February 4, 2003). These impacts were the result of a complex weather event which involved two large scale low-pressure systems, several different types of precipitation, and significant associated temperature variations over the course of 5 days.

[4] In meteorology, these are termed "meso-scale" weather phenomenon, which tend to occur on spatial scales smaller than distances between important surface observation stations, and on sub-daily (less than 24 hour) temporal scales.

A low pressure system which had originated in Alberta impacted southern Ontario on January 31st and February 1st, followed by a second low pressure system which had originally formed over Texas and Oklahoma, impacting Toronto on February 3rd and 4th. In addition to impacts to Toronto Hydro's system, power outages were also reported in Richmond Hill and Markham (Toronto Star Feb 4, 2003).

Impacts on February 1st were almost exclusively restricted to 27.6 kV equipment (except for one report), and, save for a few downed wired and tree contacts, were generally characterized generally consisted of tracking, electrical shorts and blown fuses associated with ice accretions. Beginning at around 10:30 am on February 1st through to the morning of February 3rd, several reports of electrical shorts and salt covering equipment were received, likely associated with attempts at deicing following the January 31st-February 1st storm. On February 3rd, freezing rain related reports began anew at ~5 PM and continued until 6 AM one February 4th. For this episode of severe weather, winds had been forecast to reach 70 km/h on February 3rd; maximum gusts would eventually be measured at 78 km/h (Pearson Airport) and 85 km/h at (Toronto Island Airport) the following day.

Conditions at Pearson Airport indicate that for the entire period between January 31st and February 4th the atmosphere was near or at saturation, with fog and haze being reported in conjunction with and between bouts of freezing rain, drizzle or light snow, however a total of only four hours of freezing rain were reported at Pearson Airport during that period. Temperatures crossed the 0°C boundary no less than *eight* times during this time period (**Figure C.7**).

The types of impacts, where descriptions were available, were quite different than those indicated for the December 2013 ice storm. Reports during the first portion of the event, mainly on February 1st, involved blown current limiting fuses and tracking problems. During the "break" in precipitation between February 1st and 3rd, 14 instances of *salt* related problems were addressed. Following this, a second round of precipitation, including the only reported freezing rain at Pearson Airport, combined with increasingly strong winds into February 4th, brought the first reports of galloping (mainly in Etobicoke) and only 4 reported instances of tree contacts, in addition to more blown fuses and pole top fires from icing related electrical shorts.

A *separate* storm over the Atlantic coast during the same time period, impacting the Maritimes on February 2nd and 3rd and producing 40-60 mm of ice accretion knocking out power to over 63,000 customers and causing other *very* significant damage, including roof collapses of barns and other storage buildings (EC 2003). By February 5th, 27,000 customers remained without power in New Brunswick (Toronto Star, Feb 5, 2003). The majority of repairs to the electrical system lasted for 5 days, and several locations had to be repaired twice or three times due to continued falling of ice laden trees, which was further exasperated by winds of ~75 km/h following the freezing rain (EC 2003). Massive ice accretions associated with this storm were at least partially due to the proximity of the storm to its source of moisture. Hence, while it produced similar wind speeds to the February 3rd and 4th low pressure system that affected southern Ontario, ice accretion amounts were *far* greater.

C.3.2.2 Case Study Specific Findings for January 31st-Febraury 4th

Galloping was indicated during the second storm, mainly in Toronto's west end, from what were likely a combination of ice accretions of on the order of 10 mm or less, but with winds gusting to the 70 to 80 km/h range. This is fairly close to the "15mm + 70 km/h" wind threshold indicated in previous work (CSA 2010), but may have been associated with lower ice accretion values but higher wind speeds. Additional cases would be needed to understand if galloping due to combined ice-wind loads occur in a range of wind speed and ice accretion combinations, but this case does indicate the potential for forecasting such problems when combined with monitoring of ice accretion.

Additional ice accretion, from either drizzle or light snow, coupled with several hours of reported fog or haze, is also highly likely for this event, but additional date related to this event is needed to diagnose actual accretion amounts and their causes. One should also consider that heavier precipitation may have occurred further east in North York and Scarborough, where the majority of ice accretion related impacts were reported. Indeed, several ITIS damage reports from those locations indicated ongoing snow and/or freezing rain for times when conditions at Pearson did not indicate *any* ongoing precipitation (e.g. two reports of snow in North York on the night of January 31st correspond with reports of "haze" at Toronto Pearson for the same time period). High wind and galloping conditions are likely better captured by records at Pearson Airport, since many of those incidents were reported much closer in Etobicoke.

When considering the types of impacts reported for this even, it is suggested that fog ice accretion may have slightly different characteristics than freezing rain ice accretion, which may result in slightly different impacts; i.e. when ice accretes due to fog and light drizzle in a humid environment, does it coat equipment differently than more rapidly accreting freezing rain? Did this lead to more localized problems associated with shorts and arching, in contrast to failures associated with direct physical impacts from ice loading and tree contacts? The role temperature fluctuations during and following periods of precipitation should also be investigated further. The degree of temperature variability for this event was much greater for this even when compared to the December 2013 ice storm, which again may have affected the type and degree of impacts (see **Table C.3**).

C.3.3 Large Scale Wind Storms

Large scale wind storms were identified through the Toronto Hydro Outage data for the 2000-2006 period. The maximum wind gusts reported during these storms were then compared to the number of outage events reported in the ITIS database and were also compared to the cause description, mainly identifying whether or not tree contacts were mentioned. The results of this comparison are described in **Table C.4** and illustrated in **Figure C.8**. Large scale, long duration wind events associated with low pressure systems were chosen instead of summer severe wind events associated with severe thunderstorms, since wind measurements at Pearson and Island airports were more likely to be representative of wind conditions at the damage sites for the large scale storms.

For the majority of events, a threshold wind speed of around 90 km/h emerges. A recent event on November 1, 2013, described in Toronto Hydro press releases but not well captured in ITIS, bears this out, in which 3,500 customers lost power during a wind storm which produce gusts up to 91 km/h at Pearson Airport.

It is notable that one of the most significant events, September 19, 2003 with 99 damage reports, also had the lowest reported gust at 72 km/h and is a pronounced outlier on the graph (bottom bar in **Figure C.8**), and the only other event which occurred in September shows the 2nd lowest wind speed value at 78 km/h.

To further investigate this wind speed relationship, the month of November 2005 was "back checked" to see how well a threshold of ~90 km/h was able to predict impacts to the Toronto Hydro system (**Table C.5** and **Figure C.9**). A total of 53 outage incidents were reported in ITIS for this month, with the largest number reported on November 6th and into the early morning hours of November 7th (35 reports). As indicated in **Table C.4**, these correspond with gusts of up to 89 km/h. Incidents were reported on 6 other days, with the second greatest number occurring on November 9th (9 reports). That day saw snow during the morning hours, followed by severe thunderstorm activity which resulted in one tornado in the City of Hamilton. Damage from thunderstorms is expected to be localized and therefore low wind speeds measured at Pearson airport are not surprising. The day with the third greatest number of reports also shows the second highest gust reported that month.

There are a number of potential reasons for this apparent seasonal difference between wind speed thresholds, most likely the effects of deciduous trees being still in full leaf, but, other considerations, such ground softness due temperatures remaining above freezing, must be considered given the very small sample size present here. However, data do appear indicate that threshold winds for damage increased from ~70 km/h during early fall up to ~90 km/h for late fall and winter windstorm events, and the causes listed for these impacts hint at a relationship to tree contacts.

We should mention that spring low pressure systems are also capable of producing high winds, but these do not seem to be as significant as fall season large scale wind storms. Spring severe wind storms also tend to have embedded thunderstorms, which act to further localize winds and complicate efforts to determine the representativeness of measurements. Examples of this event type include the April 20 to 21, 2000 and April 12, 2001 storms. March 9-10, 2002 is the only significant spring wind storm in the 2000-2006 period, but this event was also accompanied by severe thunderstorm activity which produced much more significant impacts in other parts of Ontario, including the loss of multiple Hydro One electrical transmission towers.

C.3.3.1 Superstorm Sandy: October 29-30, 2012

So-called "Superstorm" Sandy, responsible for major devastation in several major east coast cities in the United States, also produced impacts in Canada, including one fatality from windblown debris. Toronto Hydro estimated about 60,000 customers had lost power during the storm (T.H. Press Releases, Toronto Star 2012). Adjacent LDE Enersource reported approximately 6,000 customers lost power during the event, with 6 crews beginning restoration efforts at around 6PM on October 29th (Mississauga News 2012). Causes for these outages included the loss of three hydro poles. ORNGE air crews had also been grounded at 2 pm October 29th due to high winds (Toronto Star 2012).

Toronto Hydro had been initially criticized for not immediately declaring Level 3 status for this event and beginning repairs; however, the vice president of grid management indicated attempting repairs during the storm would have been futile and dangerous for repair crews (Toronto Star 2012). "There's nothing we could have done between 2 am and 6 am." Press releases issued as early as 6 PM on October 29th warned customers that repairs may be impossible during high winds.

A map depicting impacts and rainfall measurements for the event is provided in **Figure C.10**. Unfortunately, outage incident data appears to be incomplete for this time period (the event having occurred after 2006), and media reports for the city of Toronto lack specific damage and failure location descriptions. This is in sharp contrast to media reports from the City of Mississauga (Mississauga News 2012), the source of all media damage reports indicated in **Figure C.10**.

With the exception of one incident, wind damage reports from ITIS all appear in the southern half of the City of Toronto, and these also correspond very well with media reports of wind damage in Mississauga, as well as the difference in measured severity between Pearson (80 km/h max gust) and Toronto Island (91 km/h). There are simply too few available rain related damage reports to determine if important thresholds were reached for direct overland flooding related damage, and a comparison between Buttonville and Pearson to determine if antecedent rainfall played an important role appears to be negative. Both areas experienced similar amounts of antecedent rainfall on October 28th, followed by wind gusts of similar magnitudes on October 29th; however, only areas located southwest and southeast of Pearson reported any notable wind damage.

Toronto Hydro press releases, including those issued as early as 9:30 PM on October 29th, before the peak of the storm, in indicated trees and tree limb contact with overhead wires as the main cause of the outages (T.H. 2012). The October 30th 10:39 PM press release specifically indicated, "Toronto Hydro estimates that more than 85 per cent of outages were caused by tree contacts with power line[s]" Further indicating that repairs are expected to exceed $1 million and that other jurisdictions, which have far less tree cover, were not expected to be as heavily impacted. On the evening of October 30th, the worst affected area was roughly bounded by "Talwood Drive (north), Eglinton Ave E (south), Bayview Ave (west) and Don Mills Rd (east)"

The preponderance of tree and tree related damage in the southern portions of Toronto and Peel, coupled with the transition from wind gust regimes from 80 km/h to 90 km/h, further supports the findings from the analysis of large scale wind storms indicating wind speed thresholds of 90 km/h, again likely related to tree contacts. Budget and time limitations prevent further analysis of this event (e.g. search for impacts in Durham region) for the time being, but further research is strongly indicated.

C.4 Severe Summer Thunderstorm Events

C.4.1 July 8, 2013 Extreme Rainfall Event

"Little India resident Kurt Krausewipz, said the 'thick heavy sheets of rain,' reminded him of monsoon season in Southeast Asia." (Toronto Star, July 9, 2013)

The flash flood event on July 8th, 2013 was responsible for the largest 24 hour rainfall amount ever reported at Pearson Airport. The event was notable for a number of important impacts, including the stranding hundreds of GO transit commuters for 5 hours on a flooded train in the Don Valley (Toronto

Star, July 9, 2013), as well as an eventual tally of nearly $1 billion in insured damages (CBC.ca 2014), mainly resulting from basement flooding. It also resulted in a significant power outage event for Toronto Hydro, with approximately 300,000 customers losing power for several hours[5] (Toronto Hydro Press Release, July 9, 2013). The outage event was mainly triggered by the failure of critical infrastructure located below grade[6] at two transformer stations linking Toronto's distribution system with Ontario's electrical transmission system.

To understand the magnitude of the event, and to assist with developing a threshold for this type of failure, maps depicting rainfall amounts across the city (Cole Engineering Group, 2013) were compared with media reports of damage, as well as the locations of the two transmission stations which suffered failures during the event (Hydro One, 2014). See **Figure C.11** for station locations relative to rainfall accumulation amounts.

The extreme rainfall event began around 4 PM and produced eventual failures at Manby and Richview transformer stations, with Hydro One declaring a "Level 2 Transmission Emergency" (Hydro One 2014). Both are located within and near the area of greatest rainfall accumulations recorded for the event, located roughly along and on either side of the Etobicoke-Mississauga border (Cole Engineering Group, 2013). A rainfall total of 126 mm was reported at Pearson International Airport, with a maximum 1 hour total of 74 mm (EC 2014); however, this was roughly within the western edge of what municipal rain gauge networks indicate as a "bull's-eye" centered slightly E of Pearson International, which contained accumulations of over *130 mm* of rain (Cole Engineering Group, 2013). Richview TS is located in the *immediate center* of this area of extreme precipitation. Manby TS is located several kilometers to the south and was subject to far less rainfall in its immediate vicinity, located nearly on and just north of the 80 mm rainfall contour. It is not clear how much additional flooding at Manby TS was the result of runoff from areas further north, or if the design and characteristics of Manby TS may have made it more vulnerable to flooding than other stations. Hydro One's system officially returned to "normal" status at 2:44 PM July 15th (Hydro One 2014).

"Level 2 remained in effect until 5:34 p.m. on July 12th as Hydro One worked to reinforce the system with restored transmission connections between Richview TS and its remote terminal stations: Trafalgar TS, Cherrywood TS, Parkway TS and Claireville TS. This provided redundant supplies and vastly improved network security." (Hydro One, 2014)

It is notable that stations located near a secondary maximum over downtown Toronto (particularly Leaside TS), did not suffer the same impacts as Richview and Manby. Rainfall in the core of the downtown maximum approaching 100 mm. Toronto's climate station at the U of T campus reported 96.8 mm of rain (EC 2014), but Leaside TS is located approximately 3-4 km to the NW of the core of this

[5] In contrast to the Dec 2013 ice storm, however, the nature of the failures allowed for ~90% restoration for distribution customers by the early hours of the following morning (TH Press Release, July 9, 2013).
[6] Interviews by RSI with practitioners at the OPA for the "sister" transmission case study indicated that placement of critical infrastructure in below grade locations may have also played a critical role in the failures experienced in this case.

much smaller maximum subject to an estimated 65-70 mm rainfall, and was also not "down-stream" from another maximum as was the case for Manby TS.

Rainfall data from Pearson International also indicate possible antecedent rainfall conditions, since 26.6 mm of rain were recorded on July 7th, the day prior to the event, and a total of 31.4 mm of rain was recorded in the full week prior to the rainfall event (EC 2014). Similarly, Toronto's downtown climate station reported 38.1 mm of rainfall on July 7th and a total of 48 mm during the week preceding the July 8th flood.

"Since June 1, downtown has seen 165 mm of rain, about double the average of 87 mm." (Toronto Star July 9, 2013)

As with the Superstorm Sandy case, outage data appeared to also be lacking in the ITIS data, with only one listing indicated for this event. However, the clear cause in this case was the direct impact to transmission infrastructure, reducing the need for similar analyses conducted for other cases in which outage causes were more local and directly related to physical impacts to the distribution system.

C.4.1.1 Case Specific Findings July 8th Flood

Rainfall in excess of 100 mm in less than 24 hours, and indeed within the span of only a few hours, appears to have been required to cause the types of failures experienced at the two western Toronto stations. Antecedent rainfall may have also played a role in the flooding, generating more runoff than would have otherwise occurred. Topography and associated runoff patterns may have also played a role, particularly for Manby TS, but conclusive evidence of this would require further investigation.

This may also be a case of extreme rainfall rates under the "sub-daily" category, given that both this case and August 19, 2005 saw the majority of rainfall occur within a few hours, with a majority of the total 24 hour rainfall occurring within approximately *one* (1) hour. Extreme rainfall rates should be directly correlated with runoff efficiency and design requirements (e.g. pumping rates for mitigation, flash flood peaks, etc.) and may be important in determining how such events generate severe impacts to these systems.

While the main infrastructure that failed was indeed owned by Hydro One, these findings have direct implications of great importance to Toronto Hydro Infrastructure. Toronto Hydro was still directly and severely impacted by the failure of 3rd party infrastructure. The PIEVC process includes 3rd party infrastructure among the needed elements for review and consideration, and this is particularly relevant for the highly interconnected electrical grid as a whole. While this was not the case in this particular event, similar infrastructure owned by Toronto Hydro may be susceptible to extreme rainfall conditions. These locations and infrastructure elements should be explicitly identified and evaluated for their vulnerability.

C.4.2 August 19, 2005 Finch Washout Event

A large "supercell" thunderstorm produced significant impacts across a swath of south-central Ontario on August 19, 2005. Perhaps the most well-known and publicized impacts from the event consisted of the complete washout of a section of Finch Avenue at Black Creek in North York. In addition to this, however, there were numerous reports of basement flooding in Toronto and York region, several vehicles being swept off of roads or submerged, in addition to several thousand homes in Toronto suffering power outages, mainly in Etobicoke and Scarborough areas (Toronto Star, August 20th, 2005). The specific causes for these outages were not provided by media reports, however ITIS incident reports, coupled with the location of reported damage, indicate that outages were mainly related to flooding. Preceding the impacts in the GTA, the supercell storm produced two large, F2 tornadoes west of the city in the Listowel and Fergus areas, severely impacting farming and cottage communities.

A map of reported impacts is provided in **Figure C.12**, combining ITIS and media damage reports with meteorological measurements for comparison. A fairly clear pattern emerges in which a corridor of extreme rainfall with embedded amounts in excess of 100 mm corresponds quite well with the majority of extreme rainfall related outage incidents, indicated by red and orange circles superimposed with an "X" in a band extending from central North York ESE to Scarborough. Extreme rainfall amounts to the immediate north of Toronto were also associated with significant basement flooding in York region. A second more isolated patch of extreme rainfall may be indicated in north Etobicoke, but could also be illusory due to the suspect reading (only 24.7 mm) located north of the Finch Washout.

Interestingly enough, tree contact and wind related damage reports are generally located south of the corridor of extreme precipitation; this is consistent with the storm type. While impacting Toronto and the GTA, the storm produced a swath flooding rainfall and large hail under as a core of heavy precipitation tracked across the city, while winds gusting to ~70 km/h or more were present *south* of this core and were responsible for several minor tree contact related damage reports[7]. A comparison between wind measurements at different locations, however, could not be conducted, as wind gust data are not available for this date for Toronto's Island airport.

C.5 Extreme Heat Days

While it is generally common knowledge that during hot and humid days during the summer, air temperatures are much cooler along the shores of Lake Ontario than they are in other parts of the city, the potential impact this temperature difference may have on electrical system response is not often considered.

Table C.6 provides a comparison between three stations to determine temperature differences across the City of Toronto on days in which high heat impacts on the distribution system were indicated (see **Table C.2** for greater details). These stations are located on or very near the western, southern and northern boundaries of the City of Toronto and provide an excellent measure of the temperature differences experienced across the city. Temperature differences of between 2.6 and 5.7 degrees are evident, while the locations of impacts strongly indicate a preference for impacts to infrastructure in Etobicoke. The number of incident reports appear to be correlated to the maximum temperature, although sample size is extremely small. The average temperature difference between Pearson Airport

[7] Had the storm produced a tornado while over the city, it would have been located at the southern edge of the heavy precipitation core. Luckily, the storm changed characteristics when approaching the GTA and appears to have been no longer tornadic when impacting the area.

and Toronto Island Airport is 4.1 degrees for the four high heat days, and the difference between North York Climate Station and Toronto Island is slightly less at 3.1 degrees.

Figure C. 13 shows an example of a high heat day (July 16, 2006) in which impacts began to be reported in North York at two different transformer stations. Interestingly enough, two of the four reports are listed as “Adverse Weather/Tree Contacts”, and we are unsure of the nature of these reported causes. Either they have been mistakenly coded, or tree contacts may have occurred due to line sag, but details on the specific impact characteristics are lacking. The small number of reports indicated in North York for this date and the inter-comparison in **Table C.6**, coupled with results from the literature review and discussions with practitioners, provide additional evidence that negative impacts to the distribution system begin to appear as temperatures approach ~35°C.

This case, however, provides an excellent example of the temperature gradient often present across the City of Toronto during extreme heat days, with slightly higher temperatures occurring further from the lake. During the summer, the temperature difference between land and lake often result in the production of a lake breeze, in which cooler, heavier air over the lake flows inland, the leading edge of that air often acting as a miniature cold front. This can result in notable temperature gradients across the city, and can also trigger and/or enhance thunderstorm activity at the boundary between lake air and air further inland.

Although time and resources did not allow for more detailed assessment, a greater number of days in which extreme heat impacted the Toronto Hydro distribution system should be further investigated to help refine this threshold further. Further analysis is also needed to ensure that the impacts of other air mass boundaries (i.e. large scale fronts) are not skewing the results presented here, as similar temperature gradients can be produced through other mechanisms unrelated to the effects of the lake.

C.6 Final Conclusions

In summary, the forensic analyses resulted in the following conclusions:

- Although data sufficiency and time allotted to the project prevented the thorough investigation of many of the events identified through this forensic analysis, several avenues of future research were identified which could lead directly to improved operational maintenance and management measures, including improved forecasting of climatic impacts to assist in anticipation and preparation for significant events.
- In some cases, it was clear that Toronto Hydro operations and maintenance crews were making effective use of forecasts to help plan and optimize repair and response, such as allowing severe weather conditions to pass before full repair operations were initiated.
- In most cases, and particularly for those in which localized differences in impact severity were evident, further analysis was stymied by a lack of observational data. Even with the inclusion of additional observational data provided by TRCA (2014), spatial gaps in observations prevented the assessment and diagnosis of conditions in certain locations (e.g. December, 2013 ice storm

damage in Scarborough lacking ice accretion or temperature measures; August 19, 2005 severe thunderstorm wind speed measurements in southern portions of the city).

- The majority of power outage events identified in the 2000-2006 period were extended events lasting up to 48 hours, representing the need for sustained operational response, but the characteristics of these events differed depending on season:
    - Extended warm season events consisted of 2 or more acute weather events in quick succession, and were a combination of related hazards producing impacts (e.g. extreme heat followed by thunderstorm activity)
    - Cool season and shoulder season events tended to last several hours; when storms occurred in succession, they tended to be separated by periods of one or more days
    - The years with the greatest reported impacts to the distribution system were characterized by multiple moderate to major outage events occurring in different seasons (e.g. significant severe thunderstorm event during the summer followed by one or more wind storms during the fall season)
- Thresholds determined for wind speed and ice storm damage agree well with previous work and research, and these also appear to be *directly* related to tree contact related impacts rather than direct climatic loading of infrastructure through wind or ice accretion.
    - The 70 km/h threshold for wind gusts, originally provided by Toronto Hydro staff during Phase I, appears to be correlated with tree damage, particularly during the warm portions of the year when deciduous trees are in full leaf, resulting in secondary impacts to the distribution system; further research is needed to confirm this relationship
    - The 90 km/h threshold appears to be both related to the baseline climatic loading used in design of civil infrastructure components (see CSA 2010) as well as tree damage after deciduous trees have shed their leaves
    - The lower bound of 15 mm for freezing rain totals resulting in tree contacts with overhead systems agree well with the findings from Klaassen et al. (2003)
    - Freezing rain totals of less than 15 mm, however, may cause impacts when combined with high humidity environments near the 0°C boundary. This can specifically result in flashovers and other related impacts. While not as severe as direct damage to overhead lines and other equipment, these types of impacts can be numerous, widespread, and localized, presenting particular challenges for restoration efforts
- Overall, larger metropolitan LDCs appear to be more vulnerable to climatic events than smaller LDCs, particularly when considering overall restoration times; this is likely due a culmination of factors, not the least of which include the state and age of equipment, difficulty of access for system repair in an urban environment, and the relative proportion of staff available with respect to total number of customers and the size of a geographical area of responsibility.
- Certain regions within the city appear to be more susceptible to weather related power outages; potential regional differences in vulnerability should be investigated further. It is not clear at this time if these vulnerabilities are due to aging infrastructure, proximity to aged canopies, difficult to access infrastructure (e.g. back-lots) or some other combination of factors.

- There were several cases in which events tended to follow one-another in series, with either the restoration following a major event being hampered by subsequent smaller events, or several moderate events resulting in prolonged, multi-day outage cases where new damage occurred immediately following recovery from previous events
- Extreme rainfall impacts are worst with warm season severe thunderstorms. These were characterized by highly localized events impacting only a portion of the City, generating rainfall accumulations of over 100 mm, the majority of which (>50%) falling on during a period of *one hour*. Rainfall impacts with longer the longer duration, larger scale events investigated here (e.g. "Superstorm Sandy") appeared to be minor.
- Changes in tree health conditions such as disease and pests may also be playing a role in increasing sensitivity to damage, as suggested by analyses of the December 2013 ice storm. These represent very complex interactions, since the extent of certain disease and pests will also be affected by changing climate regimes, and their interaction with the structural integrity of trees and limbs is still unknown.
- Even for winter events, which are ostensibly much less localized in nature than warm season storms, localized differences in infrastructure impacts were evident, and without additional data, the causes for these disparities were not entirely clear. In one case (December 21-22, 2013) a small scale weather feature was explicitly identified as having very likely been a major contributor to the case overall, and similar findings are expected if similarly in-depth analyses are conducted of other high impact winter storms.
- Differences in impacts due to storm structure and other localized meteorological factors were evident in some cases (e.g. separation of precipitation and wind related impacts Aug 19, 2005). While these are to be expected, they may also assist in response to events when combined with remote sensing data, such that response crews may be better informed as to the type of impacts they may encounter following a severe storm.
- Events were not only characterized by impacts to the distribution system, but tended to consist of multiple, often severe impacts to other buildings and infrastructure, including transportation, and communication infrastructure. These impacts compounded effects on the distribution system by further complicating operational response.
- Smaller events which barely generated more than 20 damage reports, such as July 1, 2001 (lightning and rainfall) or April 28, 2002 (high winds), should be studied to understand where the lower damage thresholds may lie and/or which areas within the city or infrastructure types/categories are the *most* vulnerable
- The presence of Lake Ontario directly impacts the behaviour of certain weather hazards, generating differences in risk across the city; it generally moderates temperatures, warming areas adjacent to the lake during the cool season and cooling areas near the lake during the summer. This effect either mitigates or exacerbates the severity of hazards depending on the type of hazard (e.g. areas downtown are kept cooler during extreme heat days, but the leading edge of the lake breeze also plays a role in enhancing severe thunderstorm hazards for other portions of the city).

- The interconnectivity of Ontario's electrical grid is vital to understanding the potential impacts from atmospheric hazards; coordination between transmission providers and LDCs in risk assessment analyses may be *pivotal* in understanding and addressing these risks.

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Table C.1: Events subject to detailed investigation.

Date(s)	Event Hazard Type(s)
January 31st to February 4th, 2003	Multi-day ice accretion event; complex interactions
August 19, 2005	Flash flooding; lightning, some winds (tree contacts)
July 16, 2006	Extreme Heat; threshold/borderline event
October 29-30, 2012	Superstorm Sandy; winds, possible rainfall impacts
July 8, 2013	Flash Flooding; failure of 3rd party underground infrastructure
December 21-22, 2013	Ice Storm; mainly tree contacts

Table C.2: Toronto Hydro Events Outage Events 2000-2006 with *20 or more* incident reports.

Medium to High Impact Events T.H. Failure Database	Event Type	Number of Reports
February 23 to 25, 2000	rain and snow	49
February 3 to 4, 2000	freezing rain	37
February 16, 2000	snow and freezing rain	72
4/20/2000 and 4/21/2000	high winds and rainfall	42
May 12 to 13, 2000	wind, rain and lightning	157
6/14/2000 and 6/15/2000	lightning and "adverse weather"	58
14-Jul-00	lightning	121
7/17/2000 and 7/18/2000	lightning, some high winds, extreme heat	88
5-Jan-01	snow	28
12-Apr-01	high winds	33
1-Jul-01	rain and high wind	21
4-Jul-01	rain, lightning, and wind	21
7/22/2001 and 7/23/2001 and 7/24/2001	lightning	53
8/7/2001 to 8/9/2001	heat and humidity	72
25-Oct-01	high winds	20
1-Feb-02	high winds	29
March 9 to 10, 2002	"adverse weather"	78
28-Apr-02	high winds, rain	21
7/21/2002 to 7/22/2002	lightning, some heat and humidity	107
9/20/2002 to 9/21/2002	rain and lightning	23
1/31/2003 to 2/1/2003	snow and freezing rain	155
2/3/2003 to 2/4/2003	freezing rain	71
5/5/2003 and May 6, 2003	lightning	45
8/21/2003 and 8/22/2003	lightning, high winds and rain	58

19-Sep-03	high winds	99
10/15/2003 and 10/16/2003	high winds	81
11/12/2003 and 11/13/2003	high Winds	80
4-Jul-04	lightning, rain	43
23-Dec-04	Freezing rain	27
2/6/2005 and 02/07/2005	fog	25
6/13/2005 and 6/14/2005	lightning, some "tree contacts"	42
28-Jun-05	lightning	30
4-Jul-05	lightning, some wind and rain	68
July 11 to 12, 2005	heat and humidity	39
8/19/2005 and 8/20/2005	extreme rainfall, high winds and lightning; DETAILED ANALYSIS	162
29-Sep-05	high winds	42
6 to 7-Nov-05	high winds	35
2/17/2006 and 2/16/2006	high winds	49
31-May-06	lightning	24
6/28/2006 and 6/29/2006	lightning, rain extremes	88
10-Jul-06	rain, lightning	24
7/17/2006 & 7/18/2006	lightning, heat and humidity, some wind	66
8-Sep-06	rain, lightning	24
10/4/2006 and 10/3/2006	lightning and high winds	30
29-Oct-06	high winds	28

Table C.3: Comparison of ice accretion events with reported impacts.

Dates	Estimated Total Ice Accretion	Total # Hours **Freezing Rain** and Drizzle	Impacts
January 31-February 4, 2003	Est. ~10-12 mm (difficult given complex temperature regime and multiple	**Pearson: 4 hours (Feb 3rd);** no freezing drizzle reported, but snow, drizzle, fog and haze reported at various times	Most damage from shorted and blown fuses, tracking, few downed lines, galloping during high winds following 2nd period of precipitation; high humidity and multiple

	precipitation types)		temperature changes about 0°C
December 20-22, 2013	Est. <15 mm Downtown Toronto to 25-35 mm York and Durham Regions	**Pearson: 4, 16 and 6**, and 2, 5 and 10; **Buttonville: 8, 13 and 8**,and 1, 5 and 10; Total hours for December 20th, 21st, and 22nd, respectively	Mainly due to tree impacts, greater periods of temperatures above 0C and liquid precipitation for locations closer to downtown Toronto, significantly reducing ice accretion totals for full 3 day period

Table C.4: Comparison of highest wind gusts with large scale outage events.

Date	**Peak Measured Gusts (km/h)**	**Cause Description**[8]
25-Oct-01	Pearson: 91; Toronto Island: 82	Tree contacts 8/20
19-Sep-03	Pearson: 72; Toronto Island: 80	Tree contacts 32/99; other causes included "driving rain", "auto reclose" of breaker due to high winds
15 to 16-Oct-03	Pearson: 91; Toronto Island: 89	Tree contacts 30/81; remainder mainly "high wind/adverse weather", one report of "fuse fell open in high wind"
12 to 13-Nov-03	Pearson: 93; Toronto Island: 96	Tree contacts 16/64; remainder simply indicated as "high wind/adverse weather", some lightning
29-Sep-05	Pearson: 78	Tree contacts 28/42, rest related to high winds, including broken insulator
6 to 7-Nov-05	Pearson: 89	Tree contacts 13/35
16 to 17-Feb-06	Pearson: 91	Tree contact: 8/13 (16th) & 12/34 (17th); also some freezing rain reported on both dates, remaining[9] were generally listed as high winds, incl. one broken insulator
29-Oct-06	Pearson: 96	Tree contact: 12/28 reports
1-Nov-13	Pearson: 91	Tree contacts: 3/7 reports

Table C.5: Comparison of *all* impact reports for November 2005 to maximum gust speed.

Date	Gust Speed (Pearson Airport)	**Number of Reports**; Notes
Nov 6th	89	**35**; 2 early morning Nov 7th, considered same event
Nov 9th	59	**9**; same day F1 Tornado, Hamilton, ON; morn report include

[8] Tree contacts were counted both when coded as cause, as well as cases where cause was coded as "adverse weather" but description of impacts indicated tree contacts were responsible.
[9] One report of a "temperature extreme" causing a failure at -3°C ambient temperatures appears to be a coding error.

		snow, thunderstorms mid-day and evening, wind caused limbs on wires 3 reports, lightning related outages 3 others
Nov 11th	35	**1**; rain indicated as cause
Nov 16th	83	**4**; three high wind reports, one “no cause”, “switch fell open”
Nov 17th	59	**1**; large tree on line, rain indicated
Nov 24th	78	**2**; winds indicated as cause, possible duplicate report of one incident
Nov 25th	48	**1**; conditions indicated as “clear” no specific cause given

Table C.6: Comparison of maximum temperatures (°C) for high and extreme heat days.

Date	**Impacts (# heat related reports)**	**Pearson Airport**	**Toronto Island Airport**	**North York Climate Station**
July 17, 2000	Minor; only 2 in Etobicoke	28.6	24.4	27.0
Aug 8, 2001	33 total; 18 in Scarborough, 10 Etobicoke	37.9	34.7	37.5
July 11, 2005	19 total; 10 Etobicoke, 7 North York	35.5	29.8	34.0
July 12, 2005	18 total; 7 Etobicoke, 7 North York	34.7	31.4	34.5

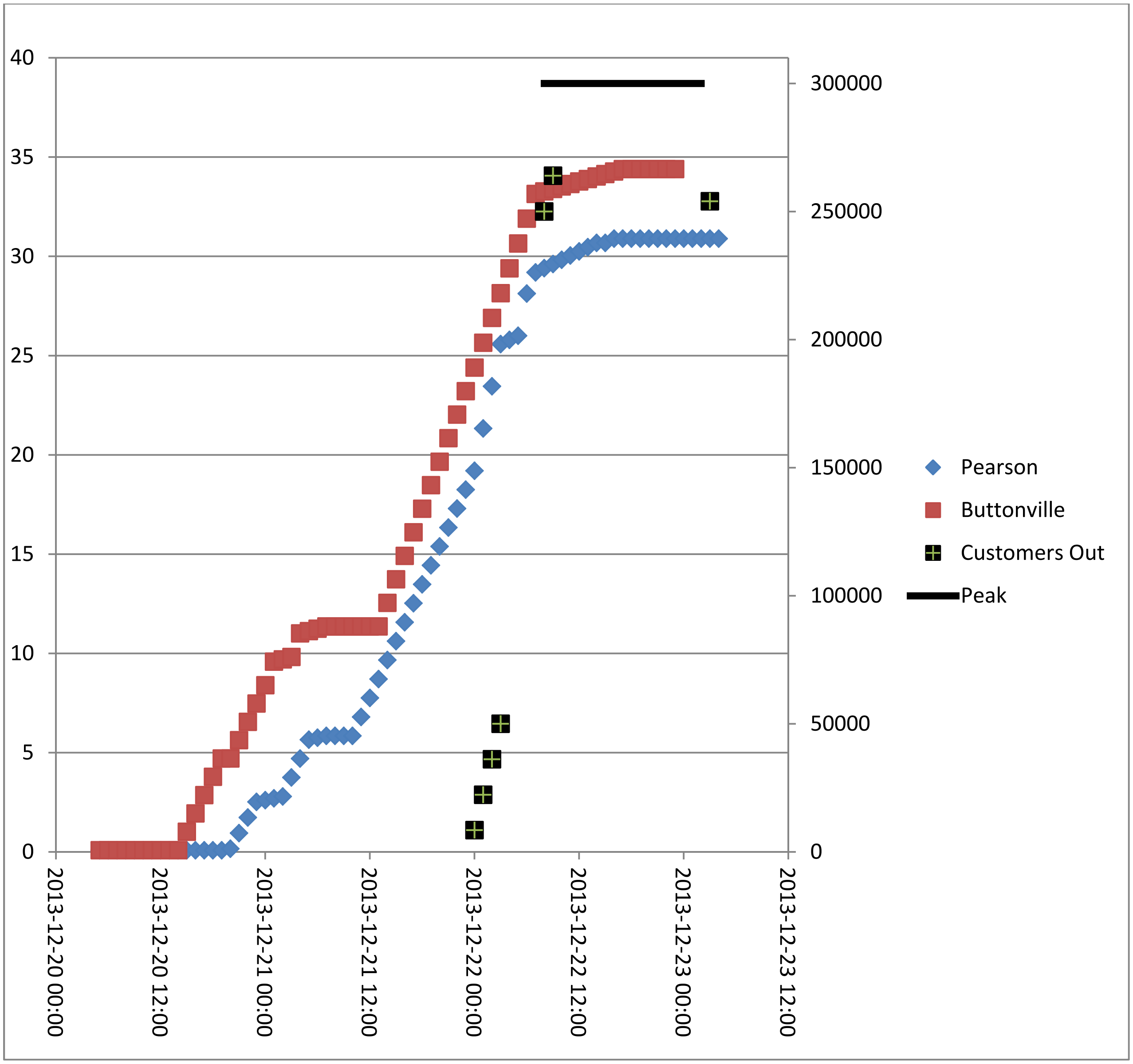


Figure C.1: Estimated ice accretion rates using observations at Pearson and Buttonville Airports. Peak outages (300,000 customers) is represented a long black bar since the exact time period in which this number of customers were without electrical service was not given and indeed may not be known.

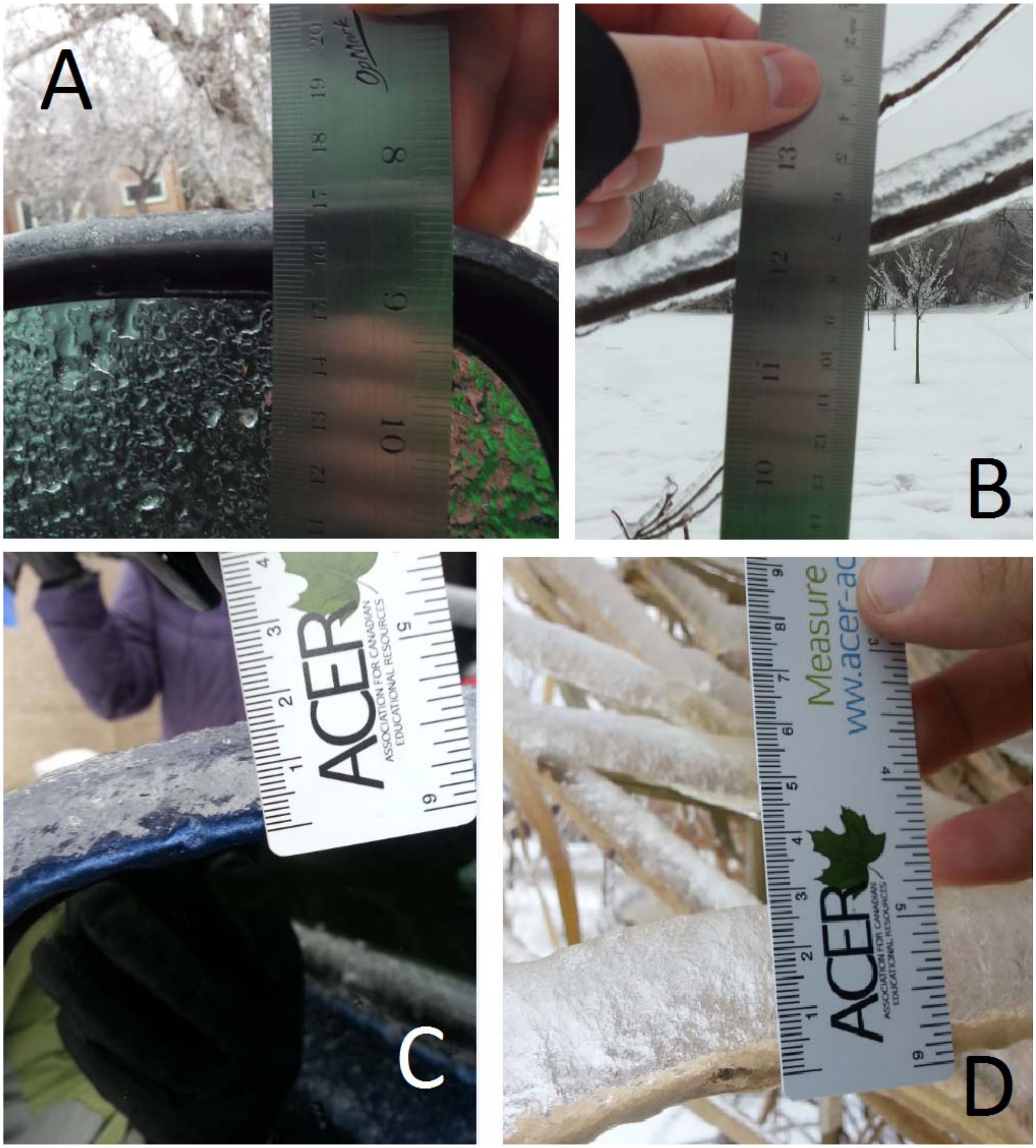


Figure C.2: Ice accretion measurements on similar objects are compared between locations in central Etobicoke (A and B), located ~5 km SE of Pearson airport, and Richmond Hill (C and D), ~9 km NW Buttonville Airport. Ice accretions on car side mirrors are measured at 6 and 15 mm and for branches of similar diameter at 10 and 23 mm, for Etobicoke and Richmond Hill locations, respectively. While measurements are not exactly equivalent in terms of exposure and accretion surface and shape characteristics, they do provide evidence that ice accretion amounts were appreciably higher for municipalities north of the City of Toronto in comparison to locations near Pearson Airport. Photos by RSI team members H. Auld (Thornhill) and S. Eng (Etobicoke).

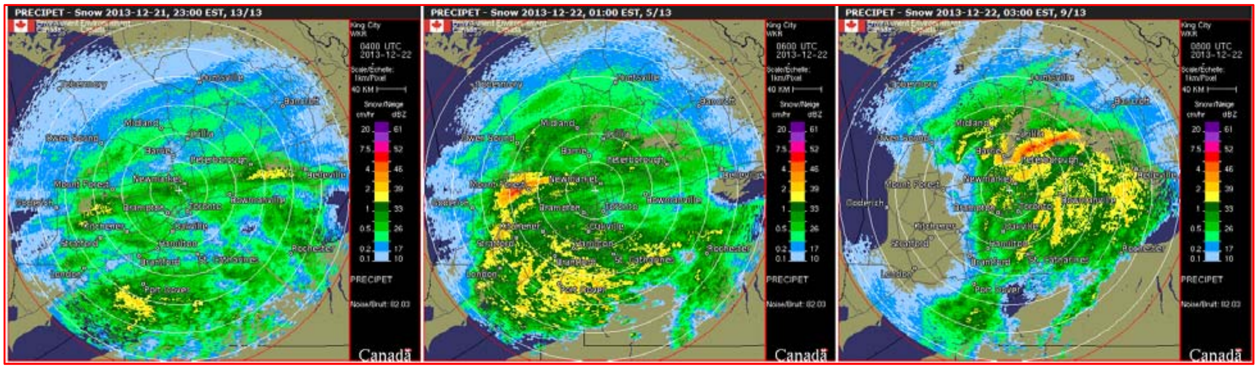


Figure C.3: King City radar imagery; panel times (left to right)correspond to 11 PM December 21st, 1 AM December 22nd and 3 AM, December 22nd, 2013. A small scale meteorological feature appears to have been responsible for an area of particularly heavy precipitation which tracked across the GTA in early morning hours, corresponding with the highest ice accretion rate estimates for the entire event.

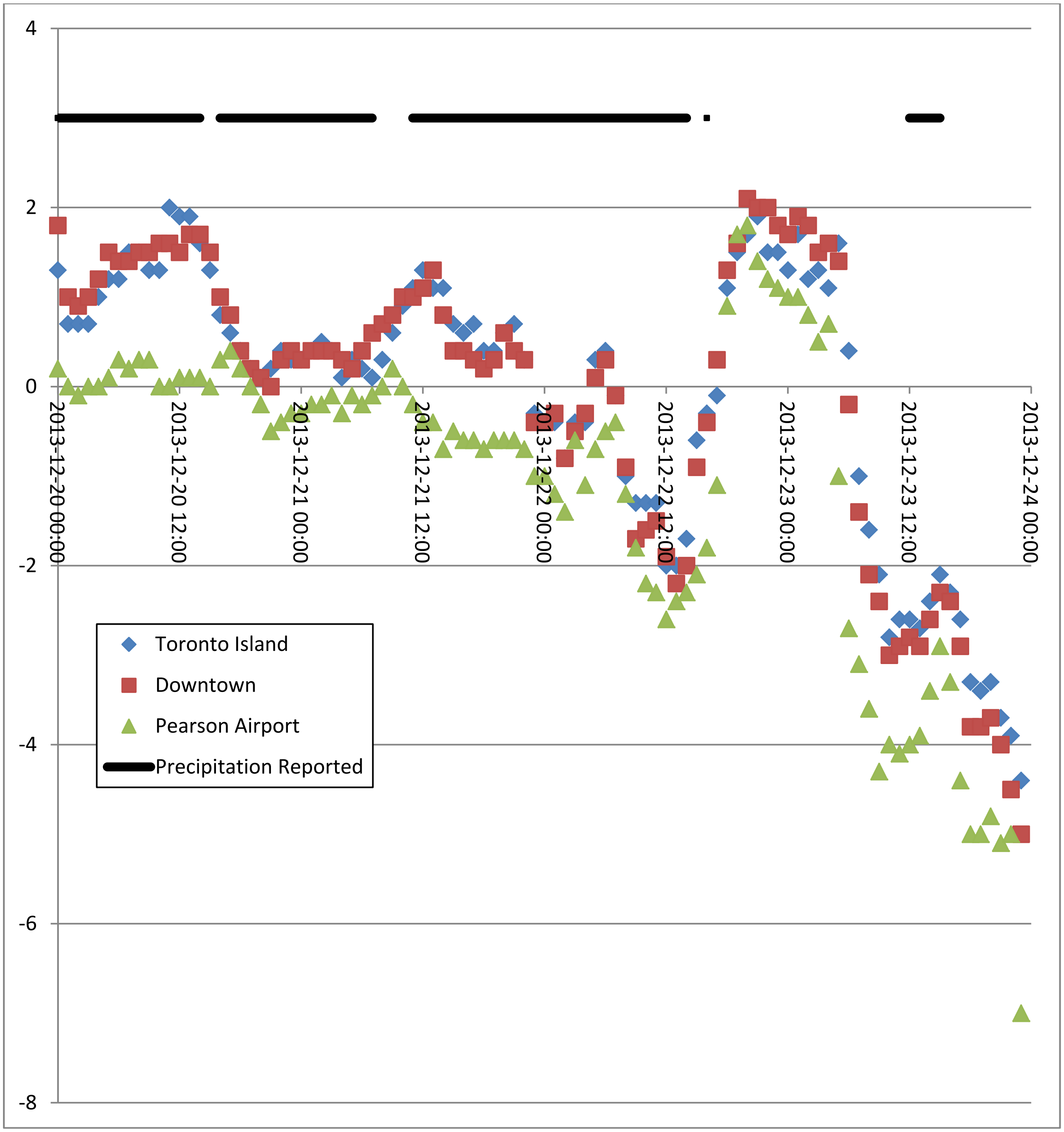


Figure C.4: Comparison of hourly temperatures between Pearson International Airport and stations located in downtown, accompanied by hours with reported precipitation. It is likely that precipitation occuring before 11 PM on December 21st did not contribute to any important ice accretion, but still resulted in significant impacts to many neighbourhoods in and around the downtown core.

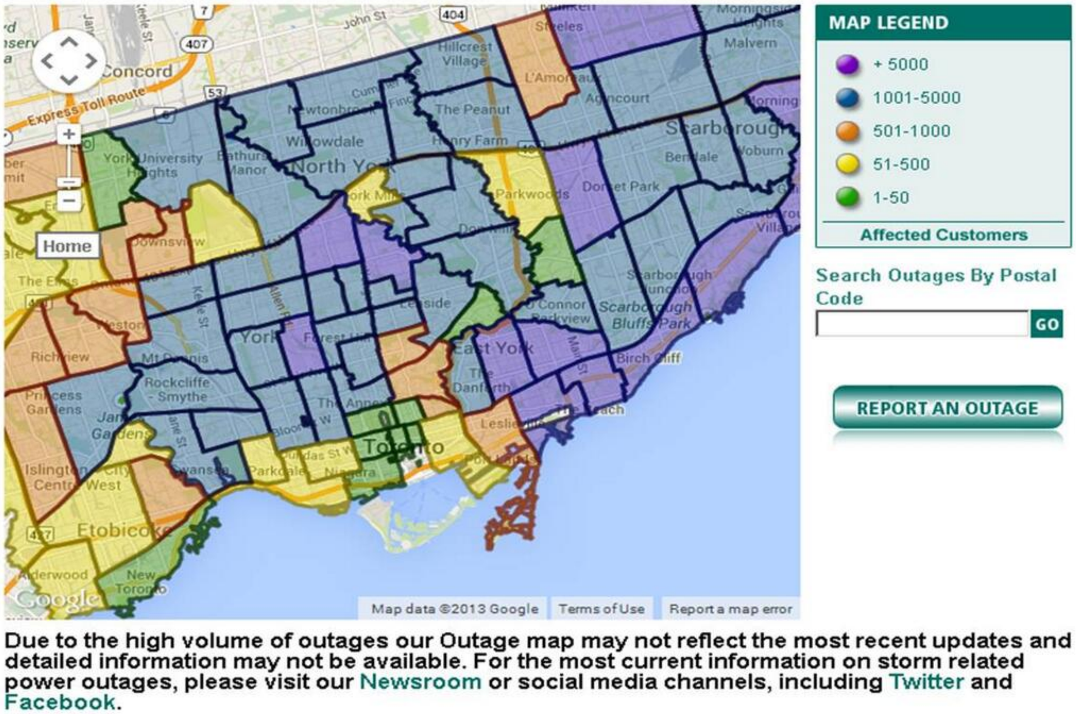


Figure C.5: Toronto Hydro outages map valid for 11 AM December 23rd. Note clear boundaries to north of Bloor and east of Woodbine/Don Valley. Unfortunately, both detailed impacts data and meteorological observations prevent better diagnoses of causes for these differences in system response to the event for areas like East York and Scarborough. Image retreived 11:50 AM December 23rd, 2013.

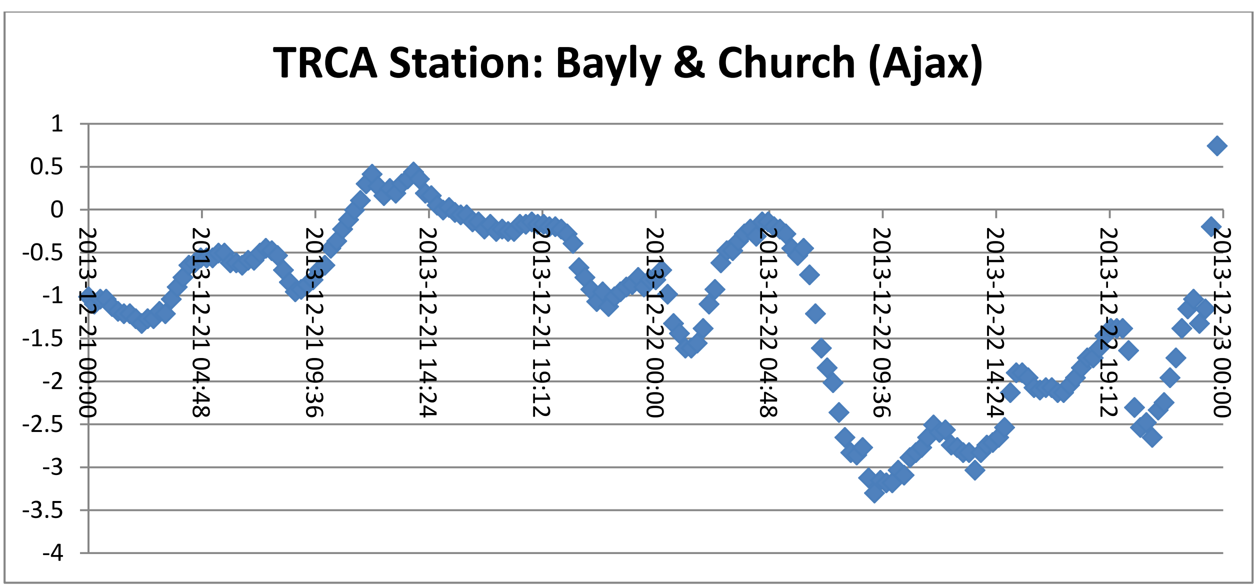


Figure C.6: Temperature Data from Bayly and Church in Ajax. When considered in conjunction with temperature and precipitation measurements from Oshawa Airport, these temerpatures indicate likelyhood that the majority of precipitation experienced between December 21st and December 23rd was in the form of freezing rain, suggesting ice accretions in Ajax were likely similar to other portions of Durham Region. Data courtesy of Toronto Region Conservation Authority.

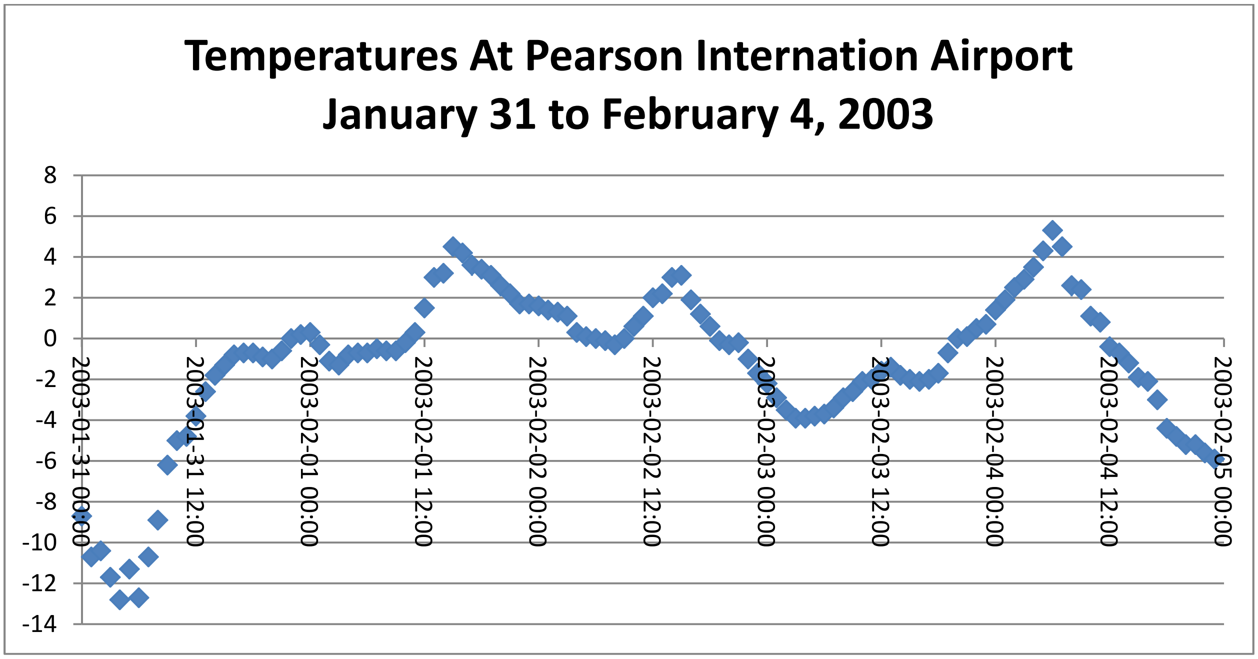


Figure C.7: Hourly temperatures at Pearson Airport between January 31st and Febraury 4th, 2003, corresponding with a complex winter event that produced a total of 160 incident reports as well as outages for over 50,000 Toronto Hydro customers. Temperatures “crossed” the 0°C line no less than 8 times during the 5 day period of unsettled weather.

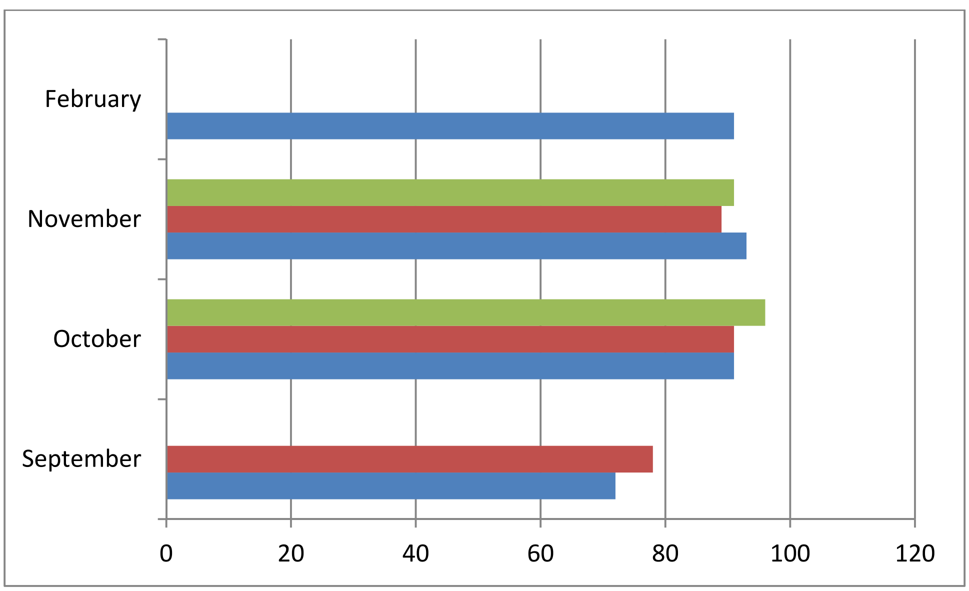


Figure C.8: Max gusts for outage events plotted by month indicate a potential relationship which deserves further study.

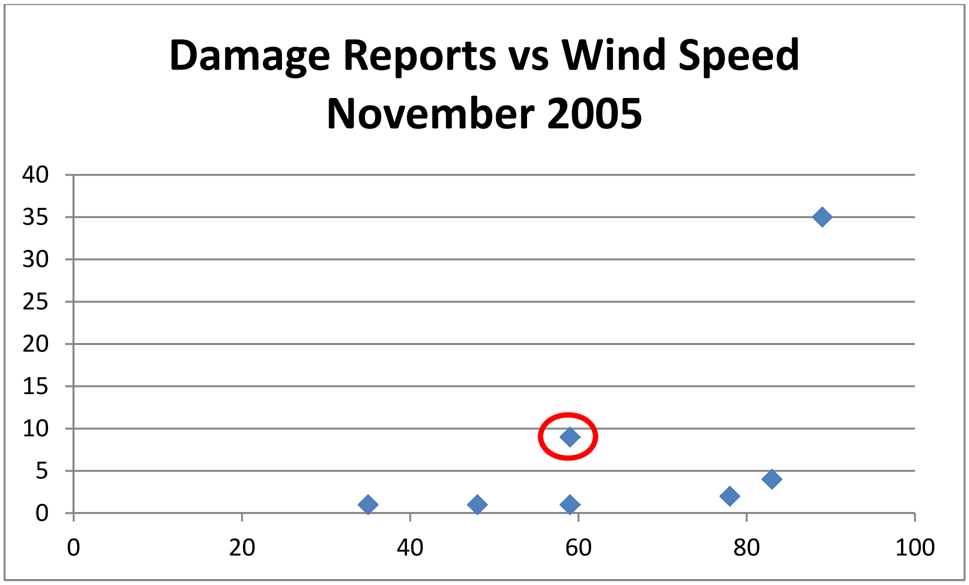


Figure C.9: Number of reports versus max gust reported for November 2005. Note the one apparent outlier, circled in **red**, is November 9th, in which localized impacts are expected and conditions at Pearson Airport are expected to be less representative of conditions producing impacts at a given site.

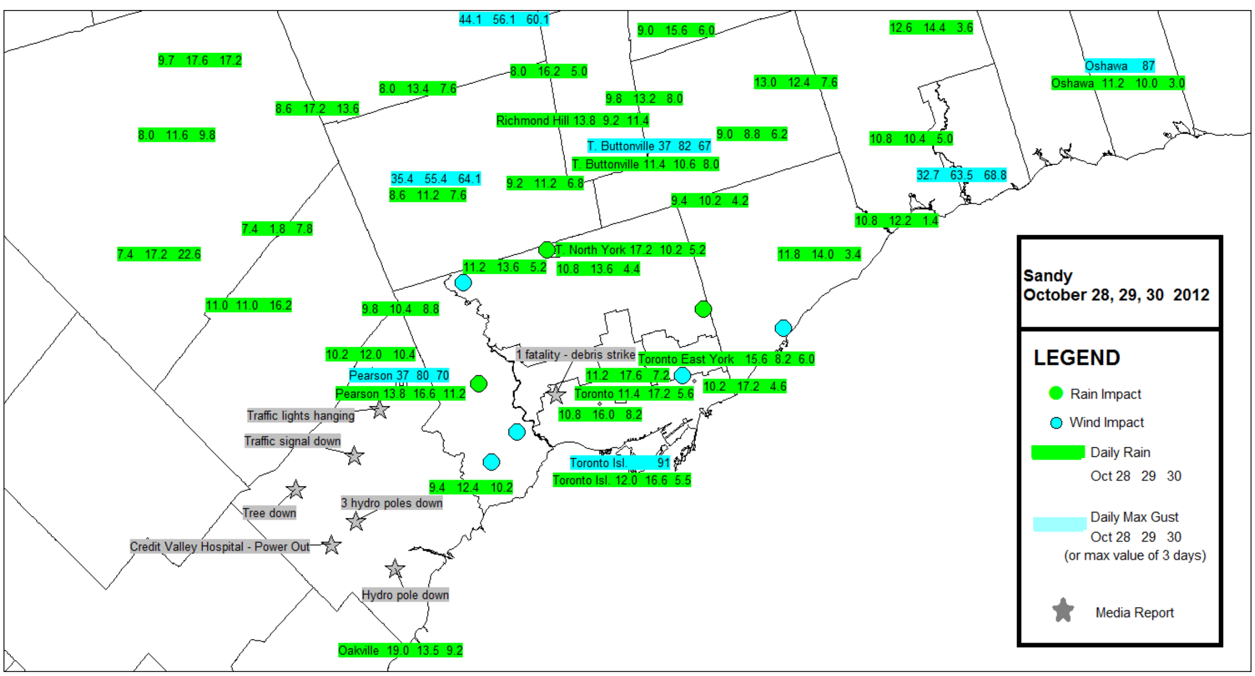


Figure C.10: Map comparing reported impacts with meteorological data for "Superstorm" Sandy. Meteorological data are for October 28th, 29th and 30th and help illustrate the progression of events. Precipitation and wind values are a combination of both EC and TRCA (2014) observational data.

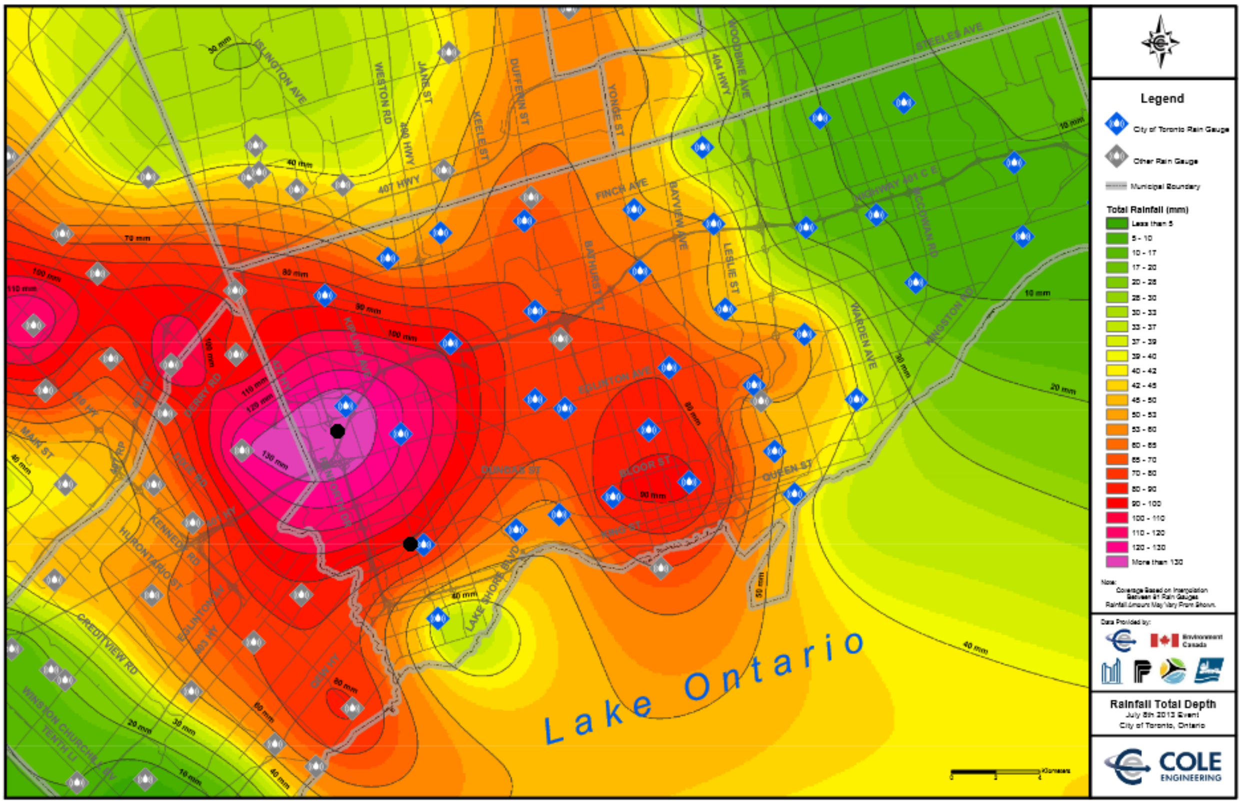


Figure C.11: Contoured 24 hour rainfall totals for the City of Toronto with the locations of Richview and Manby TS superimposed (black dots) added. High resolution PDF map of rainfall totals is available online: http://coleengineering.ca/wordpress/wp-content/themes/Evolution/pdf/2013-articles/rainfall-map.pdf (Cole Engineering Group, 2013)

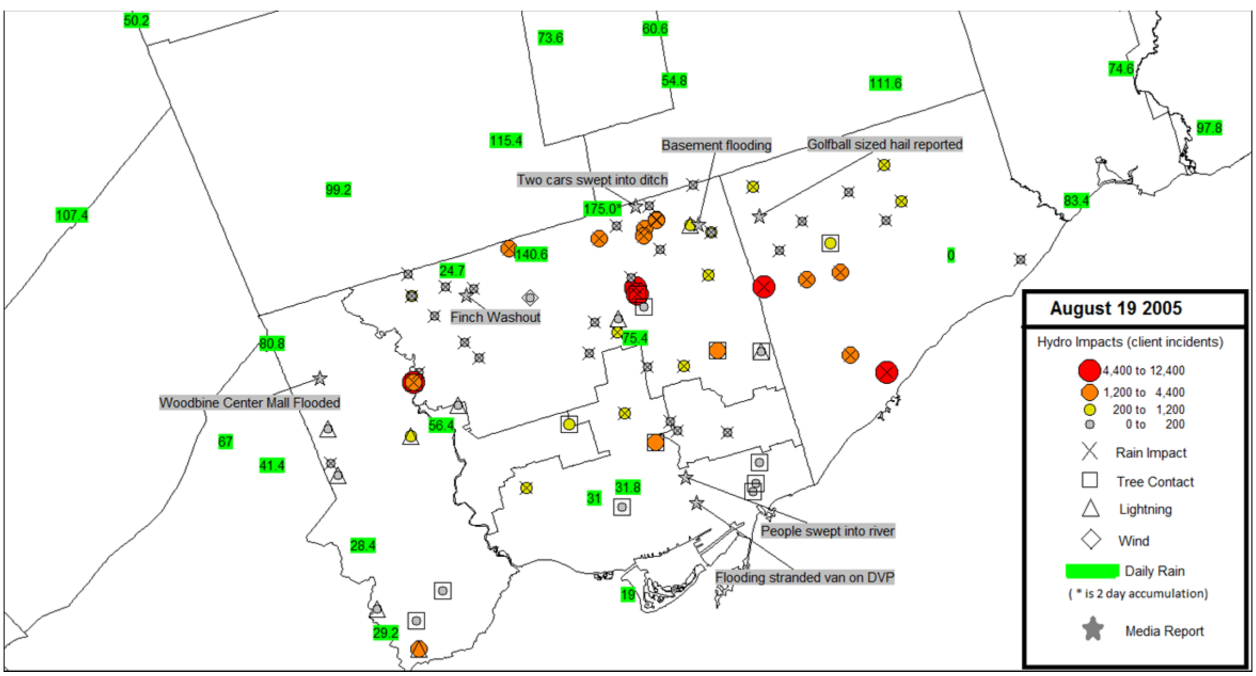


Figure C.12: August 19, 2005 severe thunderstorm event. Map of impacts combining impact types from ITIS and media reports with meteorological data.

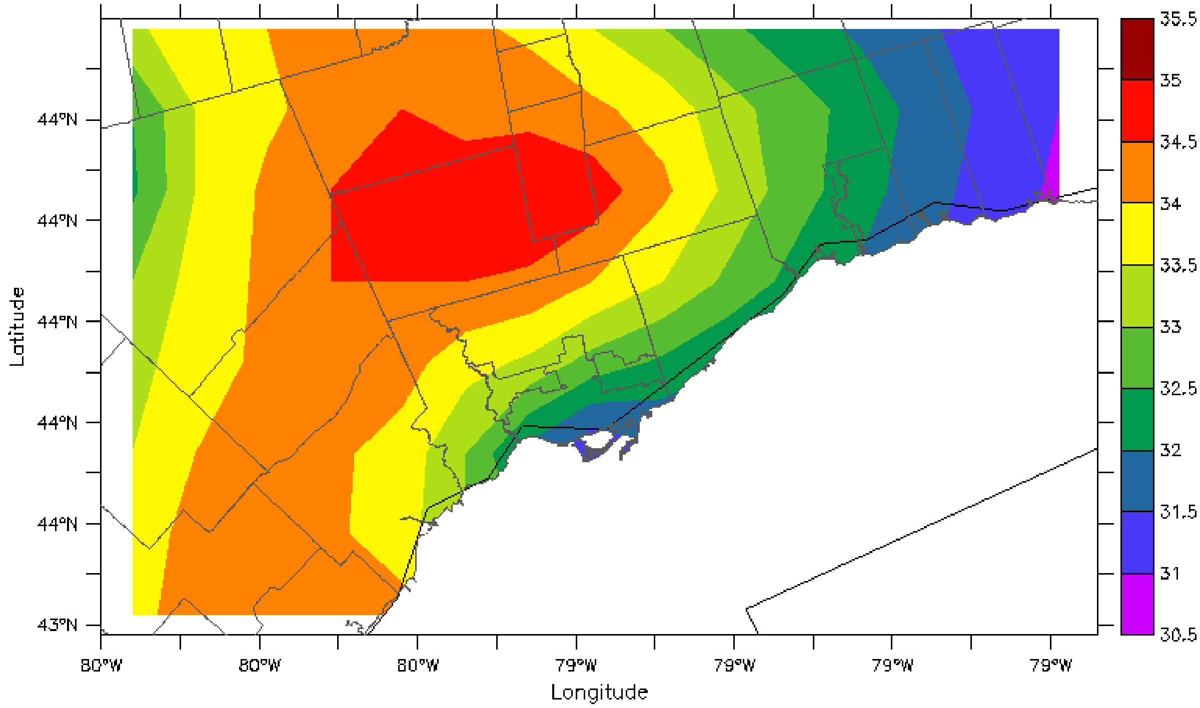


Figure C.13: July 16, 2006, maximum surface temperature (°C) for Toronto and surrounding areas. Data from Cangrd gridded data set.

Appendix D
Risk Assessment Matrix

Study Period / Infrastructure Class or Category	Evaluation: Load Projections/ Capacity / Redundancy	Other Comment	1 High Temperature: Maximum temp above 25 °C						2 High Temperature: Maximum temp above 30 °C						3 High Temperature: Maximum temp above 35 °C					
			Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
1 Transmission Step-down to Municipal																				
1.1 Former Toronto																				
1.1.1 Downtown core stations	Station capacity by 2050 : Low	Stations are indoors	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.1.2 Downtown outer stations w/o a station	Station capacity by 2050 : Low	Stations are indoors	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.1.3 Station (13.8 kV)	Station capacity by 2050 : Low	Outdoor station	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.2 Horseshoe Area																				
1.2.1 Station	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.2.2 Station	Station capacity by 2050 : Good	Stations are outdoor stations	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Power transformer : Overload	3	3	21
1.2.3 East stations	Station capacity by 2050 : Good	Stations are outdoor stations	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Power transformer : Overload	3	3	21
1.2.4 Station	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.2.5 Station (27.6 kV)	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.2.6 Station	Station capacity by 2050 : Good	Stations are outdoor stations	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Power transformer : Overload	3	3	21
1.2.7 Northwest stations	Station capacity by 2050 : Good	Stations are outdoor stations	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Power transformer : Overload	3	3	21
1.2.8 2 Stations	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
1.2.9 Southwest stations	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
2 Municipal Stations (divided by geography)																				
2.1 Toronto Hydro to Toronto Hydro & Private owner Ship																				
2.1.1 Former Toronto (indoor/outdoor)	Low	Most stations are located indoors in buildings	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21	Y	7	Power transformer : Overload	3+	4	28
2.1.2 Horseshoe Area (indoor/outdoor)	Good	Most stations are located outdoors	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Power transformer : Overload	3	3	21
2.1.3 Toronto Hydro to Private owner ship	n/a - no transfer possible	Stations are indoors	N	7			2	-1	N	7				-1	Y	7	Power transformer : Overload	3+	4	28
3 Feeder Configuration : Underground (divided by																				
3.1 Horseshoe Area: Dual Radial System (underground) &																				
3.1.1 Submersible type	moderate / usually serves multiple customers		N	7				-1	N	7	Ability to access service (see human resources)			-1	Y	7	High demand: Stressed cables and transformers	2	2	14
3.1.2 Vault type:																				
- Above ground	moderate / usually serves 1 customer		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2	2	14
- Below ground	moderate / usually serves 1 customer		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2	2	14
3.1.3 Padmount station	moderate / usually serves multiple customers		N	7				-1	N	7	idem			-1	Y	7	Pad mount transformers overheating, cables stressed	2	2	14
3.2 Former Toronto : Dual Radial System (underground) &																				
3.2.1 Submersible type	low/ usually serves multiple customers		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2+	3	21
3.2.2 Vault type:																				
- Above ground	low / usually serves 1 customer		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2+	3	21
- Below ground	low / usually serves 1 customer		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2+	3	21
3.2.3 Padmount station	low / usually serves multiple customers		N	7				-1	N	7	idem			-1	Y	7	Pad mount transformers overheating, cables stressed	2+	3	21
3.3 Compact Loop Design (underground)																				
3.3.1 Former Toronto: Subway type	Moderate to good		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2	2	14
3.4 13.8 kV Network																				
3.4.1 Former Toronto	Best		N	7				-1	N	7	idem			-1	Y	7	High demand: Stressed cables and transformers	2	2	14
3 Feeder Configuration : Overhead (divided by																				
3.5 Overhead																				
Radial																				
3.5.1 4.16 kV	Low / less affected		N	7				-1	N	7				-1	Y	7	Onan power transformers, conductors	2+	3	21
3.5.2 13.8 kV	Low / more affected		N	7				-1	N	7				-1	Y	7	Onan power transformers, conductors	2+	3	21
3.5.3 27.6 kV	Low / more affected		N	7				-1	N	7				-1	Y	7	Onan power transformers, conductors	2+	3	21
Loop																				
3.5.4 4.16 kV	Good / less affected		N	7				-1	N	7				-1	Y	7	Onan power transformers, conductors	2	2	14
3.5.5 13.8 kV	Good / more affected		N	7				-1	N	7				-1	Y	7	Onan power transformers, conductors	2	2	14
3.5.6 27.6 kV	Good / more affected		N	7				-1	N	7				-1	Y	7	Onan power transformers, conductors	2	2	14
4 Communications (divided by types)																				
4.1 Protection and control systems			Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14
4.2 SCADA + Wireless network	N/A		N	7				-1	N	7				-1	N	7				-1
5 Civil Structures (divided by categories)																				
5.1 Transmission & Municipal Stations																				
Outdoor																				
5.1.1 Equipment support			N	7				-1	N	7				-1	N	7				-1
5.1.2 Gantry			N	7				-1	N	7				-1	N	7				-1
5.2 Underground feeders : Former Toronto																				
5.2.1 Reinforced concrete cable chambers	Low		N	7				-1	N	7				-1	N	7				-1
5.2.2 Concrete vaults (reinforced)	Low		N	7				-1	N	7				-1	N	7				-1
5.2.3 Underground cable ducts	Low		N	7				-1	N	7				-1	N	7				-1
5.3 Underground feeders : Horseshoe Area																				
5.3.1 Reinforced concrete cable chambers	moderate		N	7				-1	N	7				-1	N	7				-1
5.3.2 Concrete vaults (reinforced)	moderate		N	7				-1	N	7				-1	N	7				-1
5.3.3 Underground cable ducts	moderate		N	7				-1	N	7				-1	N	7				-1
6 Human Resources																				
6.1 Emergency Response			N	7				-1	Y	7		2-3	3	21	Y	7		4	4	28

Infrastructure Class or Category	4 High Temperature: Maximum temp above 40 °C						5 Average temperature >30°C: Average temp. Over 30°C on a 24h basis						6 Heat Wave: 3 days with max temp. above 30 °C					
	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
1 Transmission Step-down to Municipal																		
1.1 Former Toronto																		
1.1.1 Downtown core stations	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.1.2 Downtown outer stations w/o a station	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.1.3 Station (13.8 kV)	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.2 Horseshoe Area																		
1.2.1 Station	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.2.2 Station	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	4	4	28
1.2.3 East stations	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	4	4	28
1.2.4 Station	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.2.5 Station (27.6 kV)	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.2.6 Station	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	4	4	28
1.2.7 Northwest stations	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	4	4	28
1.2.8 2 Stations	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
1.2.9 Southwest stations	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
2 Municipal Stations (divided by geography)																		
2.1 Toronto Hydro to Toronto Hydro & Private owner Ship																		
2.1.1 Former Toronto (indoor/outdoor)	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	4+	5	35
2.1.2 Horseshoe Area (indoor/outdoor)	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	4	4	28
2.1.3 Toronto Hydro to Private owner ship	Y	7	Power transformer : Overload	5+	6	42	Y	7	Power transformer: Overload	5+	6	42	Y	7	Power transformer: Overload	3+	4	28
3 Feeder Configuration : Underground (divided by																		
3.1 Horseshoe Area: Dual Radial System (underground) &																		
3.1.1 Submersible type	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21
3.1.2 Vault type:																		
- Above ground	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21
- Below ground	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21
3.1.3 Padmount station	Y	7	Pad mount transformers overheating	3	3	21	Y	7	Pad mount transformers overheating	3	3	21	Y	7	Pad mount transformers overheating	3	3	21
3.2 Former Toronto : Dual Radial System (underground) &																		
3.2.1 Submersible type	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	7	High demand: Stressed cables and transformers	2+	3	21	Y	7	High demand: Stressed cables and transformers	3+	4	28
3.2.2 Vault type:																		
- Above ground	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	7	High demand: Stressed cables and transformers	2+	3	21	Y	7	High demand: Stressed cables and transformers	3+	4	28
- Below ground	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	7	High demand: Stressed cables and transformers	2+	3	21	Y	7	High demand: Stressed cables and transformers	3+	4	28
3.2.3 Padmount station	Y	7	Pad mount transformers overheating, cables stressed	3+	4	28	Y	7	Pad mount transformers overheating, cables stressed	3+	4	28	Y	7	Pad mount transformers overheating, cables stressed	3+	4	28
3.3 Compact Loop Design (underground)																		
3.3.1 Former Toronto: Subway type	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21
3.4 13.8 kV Network																		
3.4.1 Former Toronto	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21
3 Feeder Configuration : Overhead (divided by																		
3.5 Overhead																		
Radial																		
3.5.1 4.16 kV	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	3+	4	28
3.5.2 13.8 kV	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	3+	4	28
3.5.3 27.6 kV	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	3+	4	28
Loop																		
3.5.4 4.16 kV	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	3	3	21
3.5.5 13.8 kV	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	3	3	21
3.5.6 27.6 kV	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	3	3	21
4 Communications (divided by types)																		
4.1 Protection and control systems	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14
4.2 SCADA + Wireless network	Y	7	Interrupters: Unusual conditions with temp over 40°C	1	1	7	N	7				-1	N	7				-1
5 Civil Structures (divided by categories)																		
5.1 Transmission & Municipal Stations																		
Outdoor																		
5.1.1 Equipment support	N	7				-1	N	7				-1	N	7				-1
5.1.2 Gantry	N	7				-1	N	7				-1	N	7				-1
5.2 Underground feeders : Former Toronto																		
5.2.1 Reinforced concrete cable chambers	N	7				-1	N	7				-1	N	7				-1
5.2.2 Concrete vaults (reinforced)	N	7				-1	N	7				-1	N	7				-1
5.2.3 Underground cable ducts	N	7				-1	N	7				-1	N	7				-1
5.3 Underground feeders : Horseshoe Area																		
5.3.1 Reinforced concrete cable chambers	N	7				-1	N	7				-1	N	7				-1
5.3.2 Concrete vaults (reinforced)	N	7				-1	N	7				-1	N	7				-1
5.3.3 Underground cable ducts	N	7				-1	N	7				-1	N	7				-1
6 Human Resources																		
6.1 Emergency Response	Y	7	health issue	5	5	35	Y	7	health issue	4	4	28	Y	7	health issue	4	4	28

Infrastructure Class or Category	7 High Nighttime Temperatures: Min temp ≥ 23°C						8 Extreme Rainfall: 100 mm <1 day + antecedent						9 Freezing Rain/Ice Storm: 15 mm (tree branches)					
	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
1 Transmission Step-down to Municipal																		
1.1 Former Toronto																		
1.1.1 Downtown core stations	Y	7	Power transformer: Overload - Load shedding	3+	4	28	Y	2	Probability of flood is low due to sump pumps in stations, 5 stations have batteries/switchgear in basement, but batteries will be moved by 2030s. Some stations will still have switchgear in basement	1+	2	4	N	7				-1
1.1.2 Downtown outer stations w/o a station	Y	7	Power transformer: Overload - Load shedding	3+	4	28	Y	2		1+	2	4	N	7				-1
1.1.3 Station (13.8 kV)	Y	7	Power transformer: Overload - Load shedding	3+	4	28	Y	2		1+	2	4	Y	7	Access to station equipment	1	1	7
1.2 Horseshoe Area																		
1.2.1 Station	Y	7	Power transformer: Overload - Load shedding	3+	4	28	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.2 Station	Y	7	Power transformer: Overload - Load shedding	3	3	21	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.3 East stations	Y	7	Power transformer: Overload - Load shedding	3	3	21	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.4 Station	Y	7	Power transformer: Overload - Load shedding	3+	4	28	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.5 Station (27.6 kV)	Y	7	Power transformer: Overload - Load shedding	3+	4	28	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.6 Station	Y	7	Power transformer: Overload - Load shedding	3	3	21	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.7 Northwest stations	Y	7	Power transformer: Overload - Load shedding	3	3	21	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.8 2 Stations	Y	7	Power transformer: Overload - Load shedding	3+	4	28	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.9 Southwest stations	Y	7	Power transformer: Overload - Load shedding	3+	4	28	N	6				-1	Y	7	Access to station equipment	1	1	7
2 Municipal Stations (divided by geography)																		
2.1 Toronto Hydro to Toronto Hydro & Private owner Ship																		
2.1.1 Former Toronto (indoor/outdoor)	Y	7	Power transformer: Overload - Load shedding	3+	4	28	N	6	No batteries in basement by 2030s	6	6	-1	N	7				-1
2.1.2 Horseshoe Area (indoor/outdoor)	Y	7	Power transformer: Overload - Load shedding	3	3	21	N	6	No batteries in basement by 2030s	6	6	-1	Y	7	Access to station equipment	0	0	0
2.1.3 Toronto Hydro to Private owner ship	Y	7	Power transformer: Overload	3+	4	28	N	6				-1	N	7				-1
3 Feeder Configuration : Underground (divided by																		
3.1 Horseshoe Area: Dual Radial System (underground) &																		
3.1.1 Submersible type	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	6	Water treeing, flooding, reduced dielectric strength	3	3	18	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3.1.2 Vault type:																		
- Above ground	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	6	Access	1	1	6	N	7				-1
- Below ground	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	6	All electrical components (not submersible), + 2 if pumps fails	5	5	30	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3.1.3 Padmount station	Y	7	Pad mount transformers overheating	3	3	21	Y	6	Access	1	1	6	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3.2 Former Toronto : Dual Radial System (underground) &																		
3.2.1 Submersible type	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	6	Water treeing, flooding, reduced dielectric strength	3+	4	24	Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14
3.2.2 Vault type:																		
- Above ground	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	6	Access	1+	2	12	N	7				-1
- Below ground	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	6	All electrical components (not submersible), + 2 if pumps fails	5+	6	36	Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14
3.2.3 Padmount station	Y	7	Pad mount transformers overheating, cables stressed	3+	4	28	Y	6	Access	1+	2	12	Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14
3.3 Compact Loop Design (underground)																		
3.3.1 Former Toronto: Subway type	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	6	Water treeing, flooding, reduced dielectric strength	3	3	18	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3.4 13.8 kV Network																		
3.4.1 Former Toronto	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	6	Old N/W protectors are not submersible	5	5	30	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3 Feeder Configuration : Overhead (divided by																		
3.5 Overhead																		
Radial																		
3.5.1 4.16 kV	Y	7	Onan power transformers	1+	2	14	N	6	Note: severity score for light rainfall. Mist + humidity = Visibility.	1+	2	-1	Y	7	Conductors (tree contacts)	5+	6	42
3.5.2 13.8 kV	Y	7	Onan power transformers	1+	2	14	N	6	Severity score for light rainfall. Mist + humidity = Visibility. Light rainfall + dirt = flash over	3+	4	-1	Y	7	Conductors (tree contacts)	5+	6	42
3.5.3 27.6 kV	Y	7	Onan power transformers	1+	2	14	N	6	idem.	3+	4	-1	Y	7	Conductors (tree contacts)	5+	6	42
Loop																		
3.5.4 4.16 kV	Y	7	Onan power transformers	1	1	7	N	6	Note: severity score for light rainfall: Mist + humidity = Visibility.	1	1	-1	Y	7	Conductors (tree contacts)	5	5	35
3.5.5 13.8 kV	Y	7	Onan power transformers	1	1	7	N	6	Severity score for light rainfall. Mist + humidity = Visibility. Light rainfall + dirt = flash over	3	3	-1	Y	7	Conductors (tree contacts)	5	5	35
3.5.6 27.6 kV	Y	7	Onan power transformers	1	1	7	N	6	idem	3	3	-1	Y	7	Conductors (tree contacts)	5	5	35
4 Communications (divided by types)																		
4.1 Protection and control systems	Y	7	Batteries: lifespan	2	2	14	N	6	Batteries will be moved to ground floor by 2030s	6	6	-1	N	7				-1
4.2 SCADA + Wireless network	N	7				-1	N	6				-1	N	7				-1
5 Civil Structures (divided by categories)																		
5.1 Transmission & Municipal Stations																		
Outdoor																		
5.1.1 Equipment support	N	7				-1	Y	6	Corrosion	0	0	0	N	7				-1
5.1.2 Gantry	N	7				-1	Y	6	Corrosion	0	0	0	N	7				-1
5.2 Underground feeders : Former Toronto																		
5.2.1 Reinforced concrete cable chambers	N	7				-1	Y	6	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	12	Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14
5.2.2 Concrete vaults (reinforced)	N	7				-1	Y	6	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	12	Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14
5.2.3 Underground cable ducts	N	7				-1	N	6				-1	N	7				-1
5.3 Underground feeders : Horseshoe Area																		
5.3.1 Reinforced concrete cable chambers	N	7				-1	Y	6	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	6	Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7
5.3.2 Concrete vaults (reinforced)	N	7				-1	Y	6	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	6	Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7
5.3.3 Underground cable ducts	N	7				-1	N	6				-1	N	7				-1
6 Human Resources																		
6.1 Emergency Response	Y	7		0	0	0	Y	6	access to site, delays, rain to stop	2-3	3	18	Y	7	safe access to site	4	4	28

10		Freezing Rain/Ice Storm				11		Freezing Rain/Ice Storm				12		High Winds				13		High Winds			
		25 mm (design threshold)						60 mm(major outages)						70 km/h+ (tree branches)						90 km/h (min design value; TH higher??)			
Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
N	7				-1	N	4				-1	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Exit lines	6	6	42	Y	4	Exit lines: overhead	7	7	28	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				-1	N	7				-1
N	7				-1	N	4				-1		7				0	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4		7				0	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				-1	N	7				-1
Y	7	Poles & conductors downed, Salt+Contamination	6+	7	49	Y	4	Poles & conductors downed, Salt+Contamination	6+	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49
Y	7	Poles & conductors downed, Salt+Contamination	6	6	42	Y	4	Poles & conductors downed, Salt+Contamination	6	6	24	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Access	1	1	7	Y	4	Access	1	1	4	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	1	1	7	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	8	N	7				-1	N	7				-1
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	8	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	4	N	7				-1	N	7				-1
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	4	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1
Y	7	safe access to site	6	6	42	Y	4	safe access to site	6	6	24	Y	7	access, location has to be declare safe	2	2	14	Y	7	access, location has to be declare safe	2	2	14

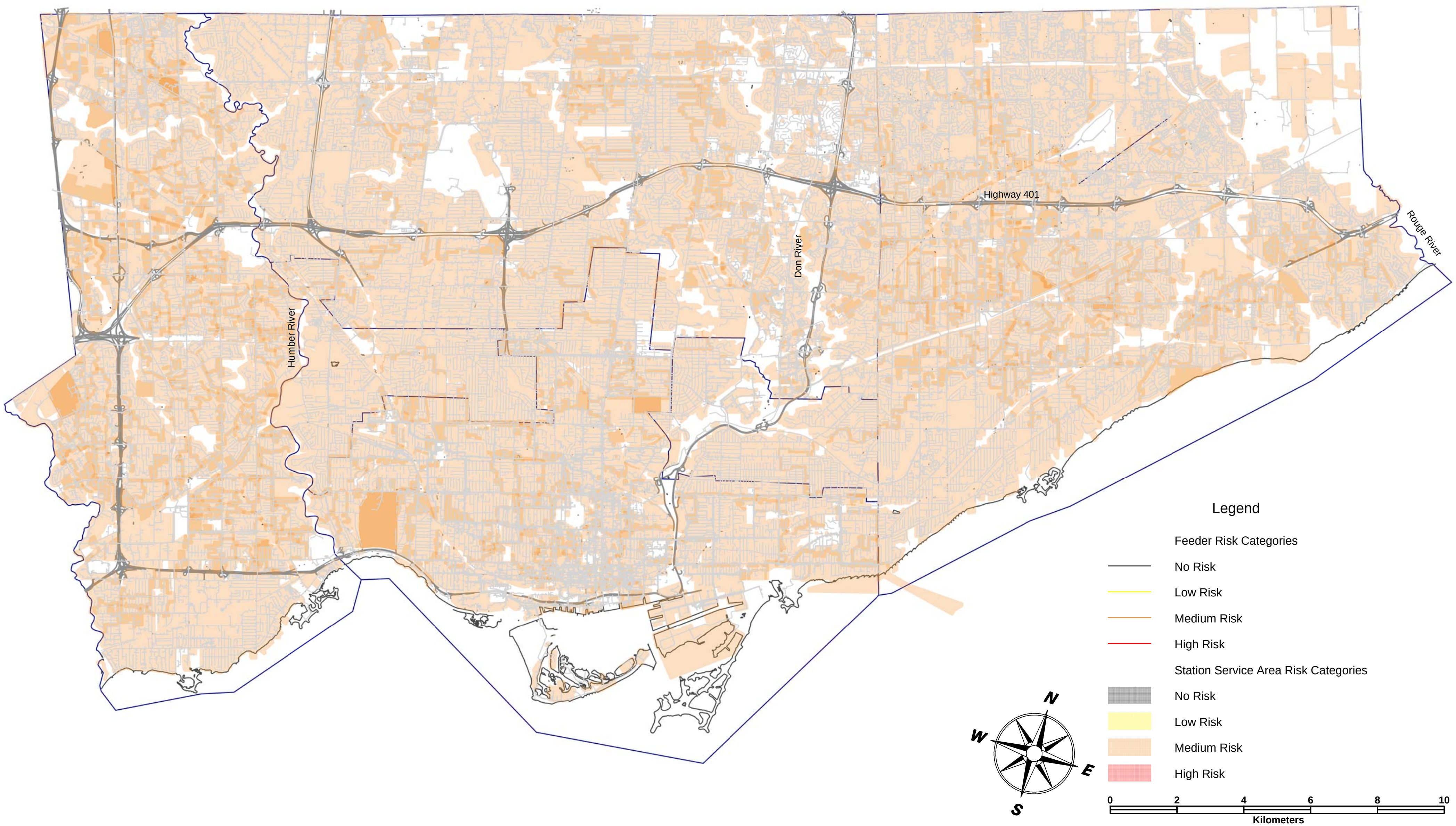
14		High Winds				15		Tornadoes				16		Tornadoes				17		Lightning			
		120 km/h						EF1+						EF2+ (concrete poles, permanent structures)									
Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
N	7				-1	Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	N	6				-1
N	7				-1	Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	N	6				-1
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36
Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36
N	7				-1	Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	N	6				-1
Y	7	Exit lines, and flying debris could impact the equipement	6	6	42	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36
N	7				-1	N	1				-1	N	0				-1	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
Y	7	Debris could impact the equipement	1	1	7	Y	1	Pad mount equipment can be damaged	2	2	2	Y	0	Pad mount equipment can be damaged	2	2	0	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
Y	7	Debris could impact the equipement	1+	2	14	Y	1	Pad mount equipment can be damaged	2+	3	3	Y	0	Pad mount equipment can be damaged	2+	3	0	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
Y																							
Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4+	5	30
Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4+	5	30
Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4+	5	30
Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4	4	24
Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4	4	24
Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4	4	24
N	7				-1	N	1				-1	N	0				-1	N	6				-1
N	7				-1	N	1				-1	N	0				-1	Y	6	Equipment could fail if protection won't work	3	3	18
Y	7	TC & CVT structures			0	Y	1	All supports	7	7	7	Y	0	All supports	7	7	0	N	6				-1
N	7				-1	Y	1	Gantry	7	7	7	Y	0	Gantry	7	7	0	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
N	7				-1	N	1				-1	N	0				-1	N	6				-1
Y	7	access, location has to be declare safe	2	2	14	Y	1	access, location has to be declare safe	2	2	2	Y	0	access, location has to be declare safe	2	2	0	Y	6	staff security	3-4	4	24

18		Snow				19		Snow				20		Frost (ground)			
		Days with > 5 cm						Days with > 10 cm						Extreme cold weather			
Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
N	7				-1	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7				-1
					0						0						
N	7				-1	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	7				-1	Y	7	Foundations, frost heave	2	2	14
N	7				-1	N	7				-1	Y	7	Foundations, frost heave	2	2	14
Y	7	Salt corrosion - concrete and steel	1+	2	14	Y	7	Salt corrosion - concrete and steel, access	1+	2	14	Y	7	Foundations, frost heave	1+	2	14
Y	7	Salt corrosion - concrete and steel	1+	2	14	Y	7	Salt corrosion - concrete and steel, access	1+	2	14	Y	7	Foundations, frost heave	1+	2	14
N	7				-1	N	7				-1	Y	7	Foundations, frost heave	1+	2	14
Y	7	Salt corrosion - concrete and steel	1	1	7	Y	7	Salt corrosion - concrete and steel, access	1	1	7	Y	7	Foundations, frost heave	1	1	7
Y	7	Salt corrosion - concrete and steel	1	1	7	Y	7	Salt corrosion - concrete and steel, access	1	1	7	Y	7	Foundations, frost heave	1	1	7
N	7				-1	N	7				-1	Y	7	Foundations, frost heave	1	1	7
Y	7	Access, staff security	1-2	2	14	Y	7	Access, staff security	3	3	21	N	7				-1

Appendix E
Risk Maps

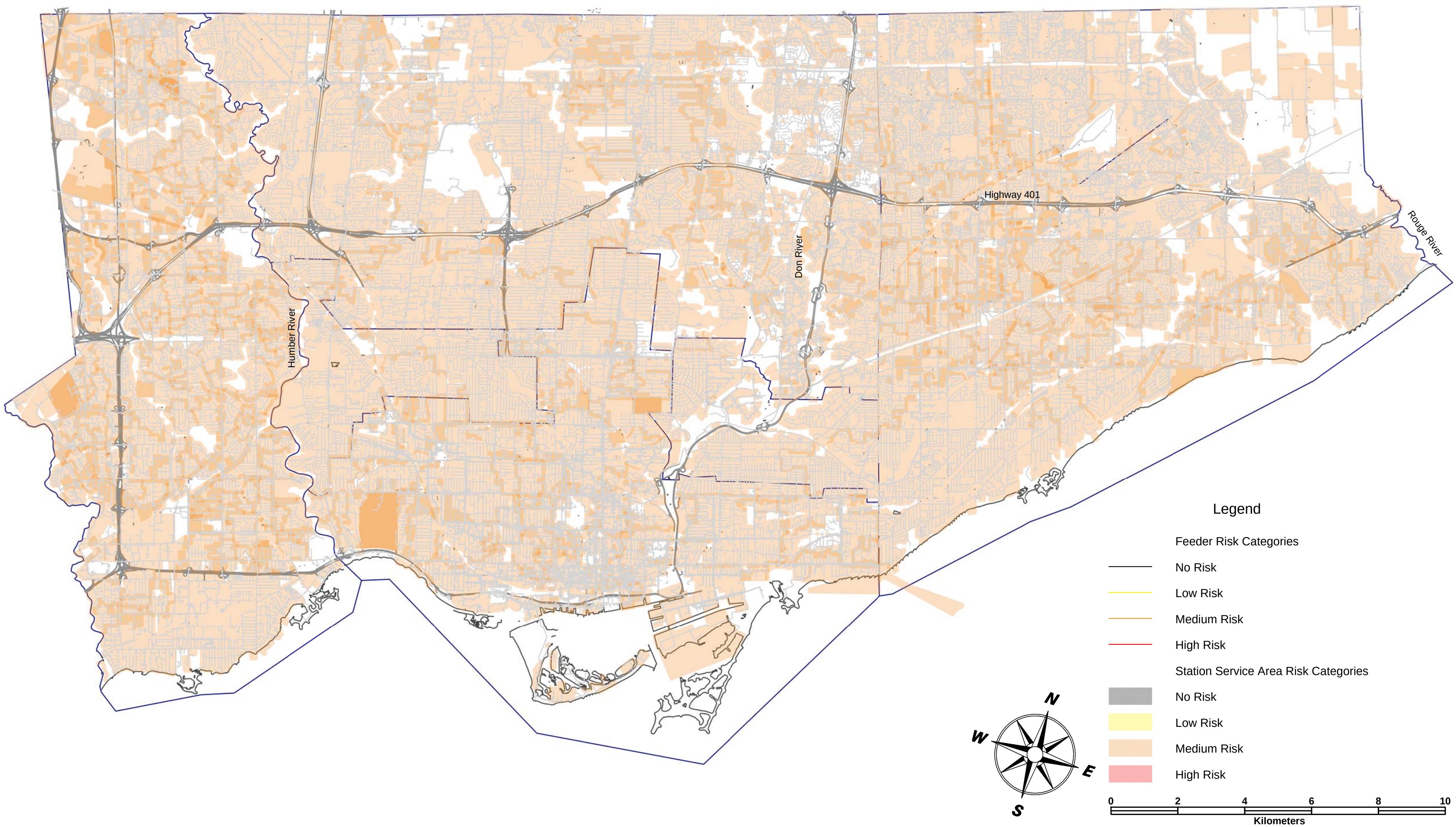
PIEVC Phase 2 Climate Change Risk Map by 2050

1. High Temperature Maximum Above 25 C



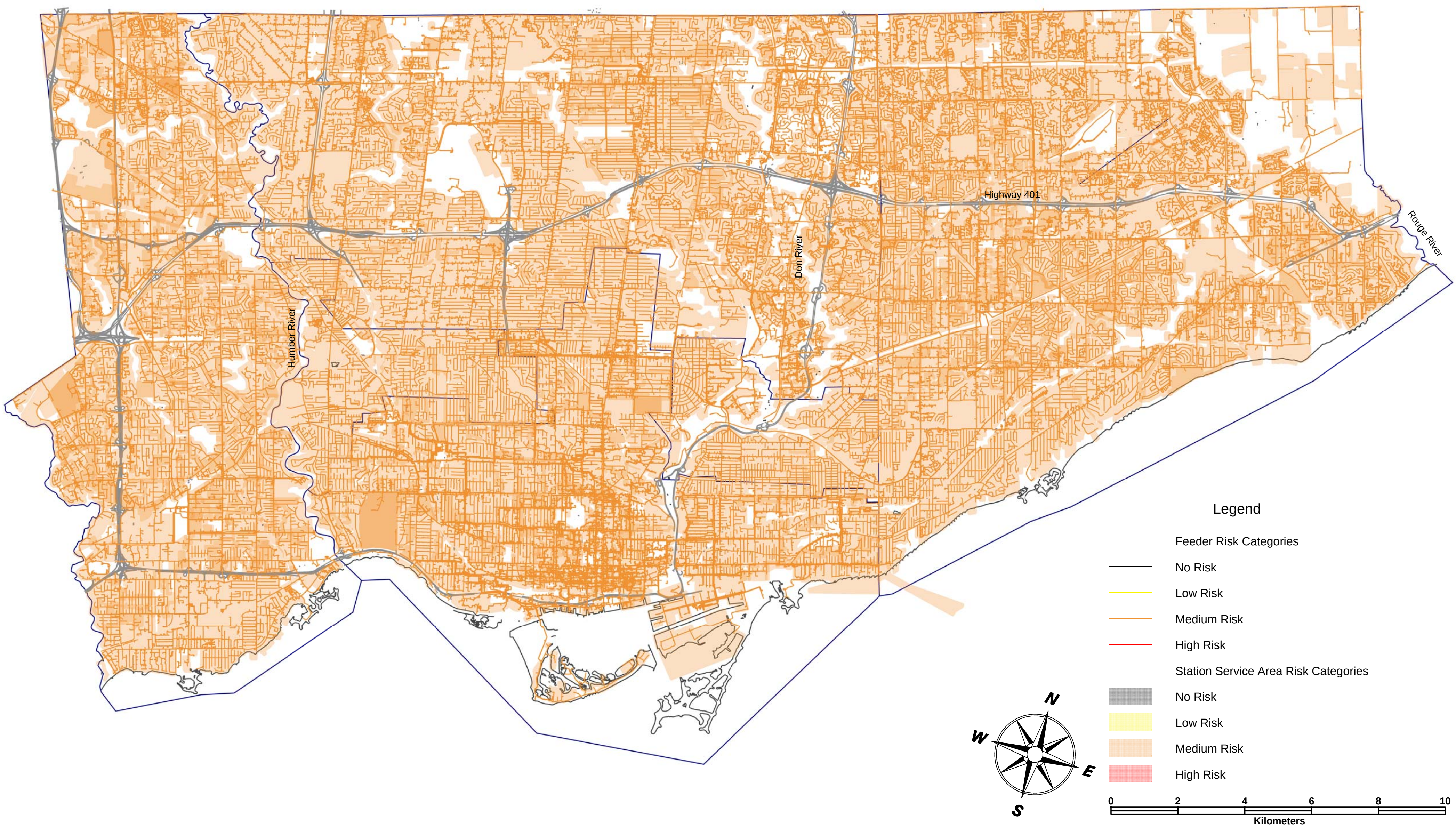
PIEVC Phase 2 Climate Change Risk Map by 2050

2. High Temperature Maximum Above 30 C



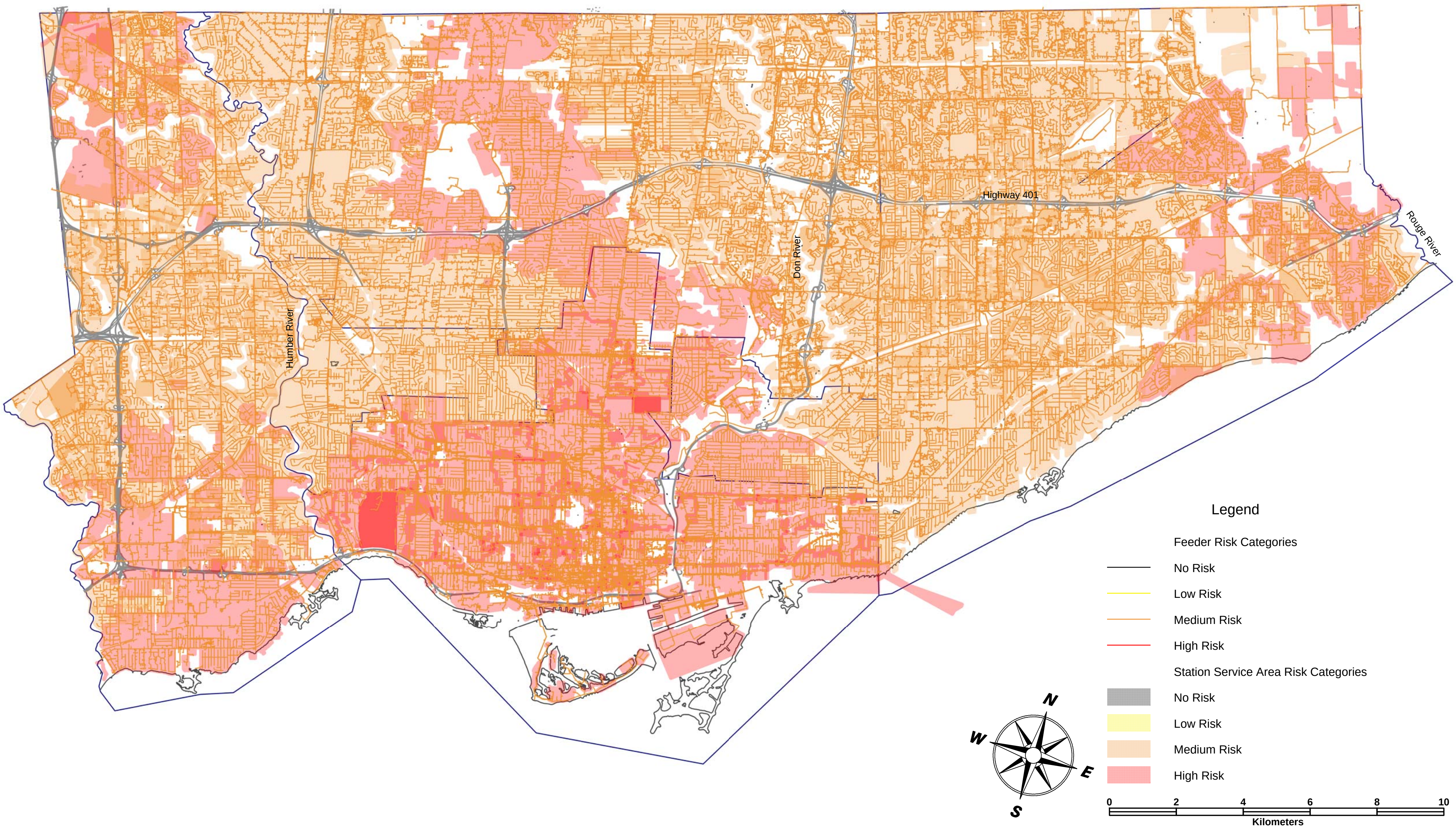
PIEVC Phase 2 Climate Change Risk Map by 2050

3. High Temperature Maximum Above 35 C



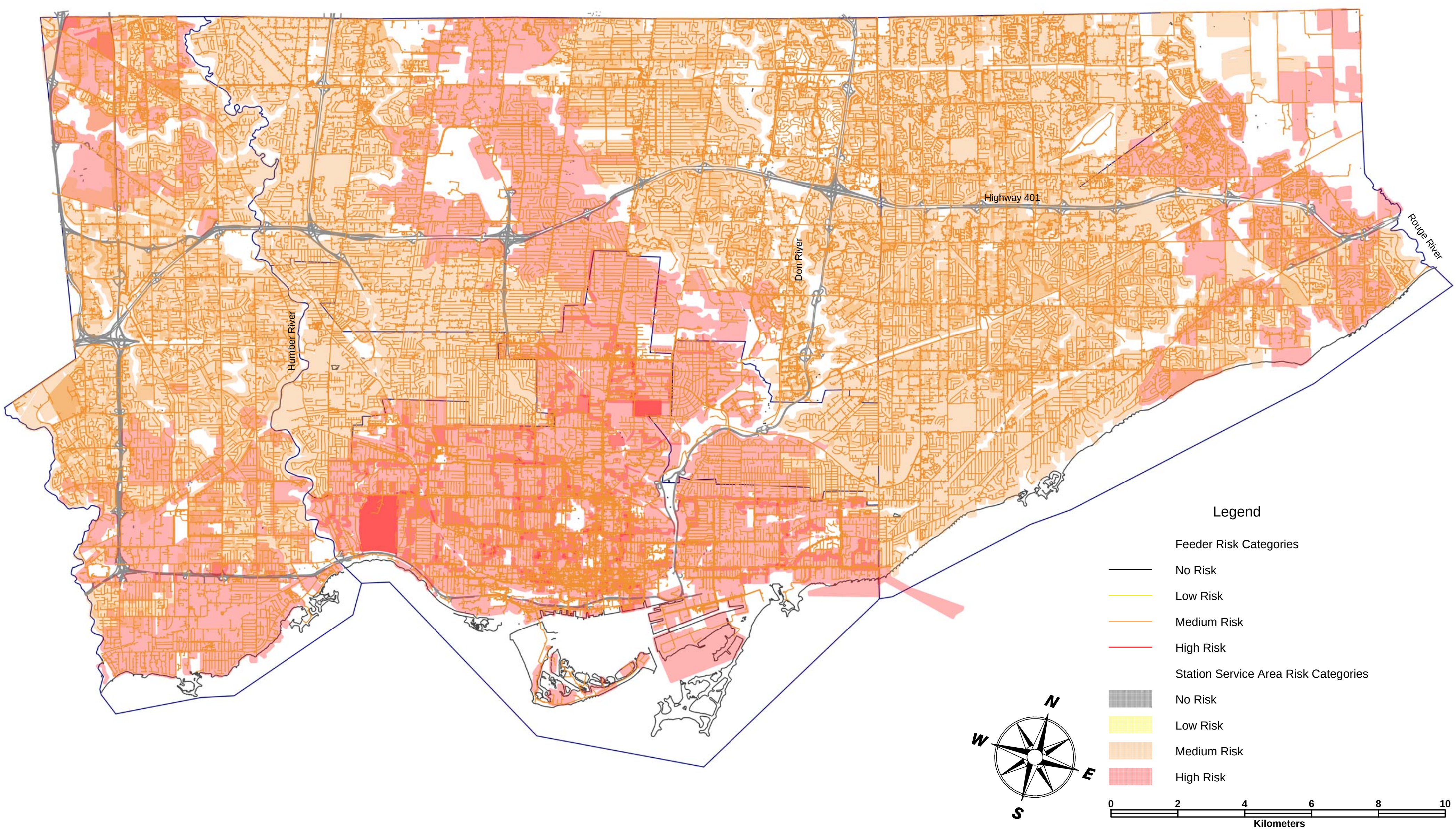
PIEVC Phase 2 Climate Change Risk Map by 2050

4. High Temperature Maximum Above 40 C



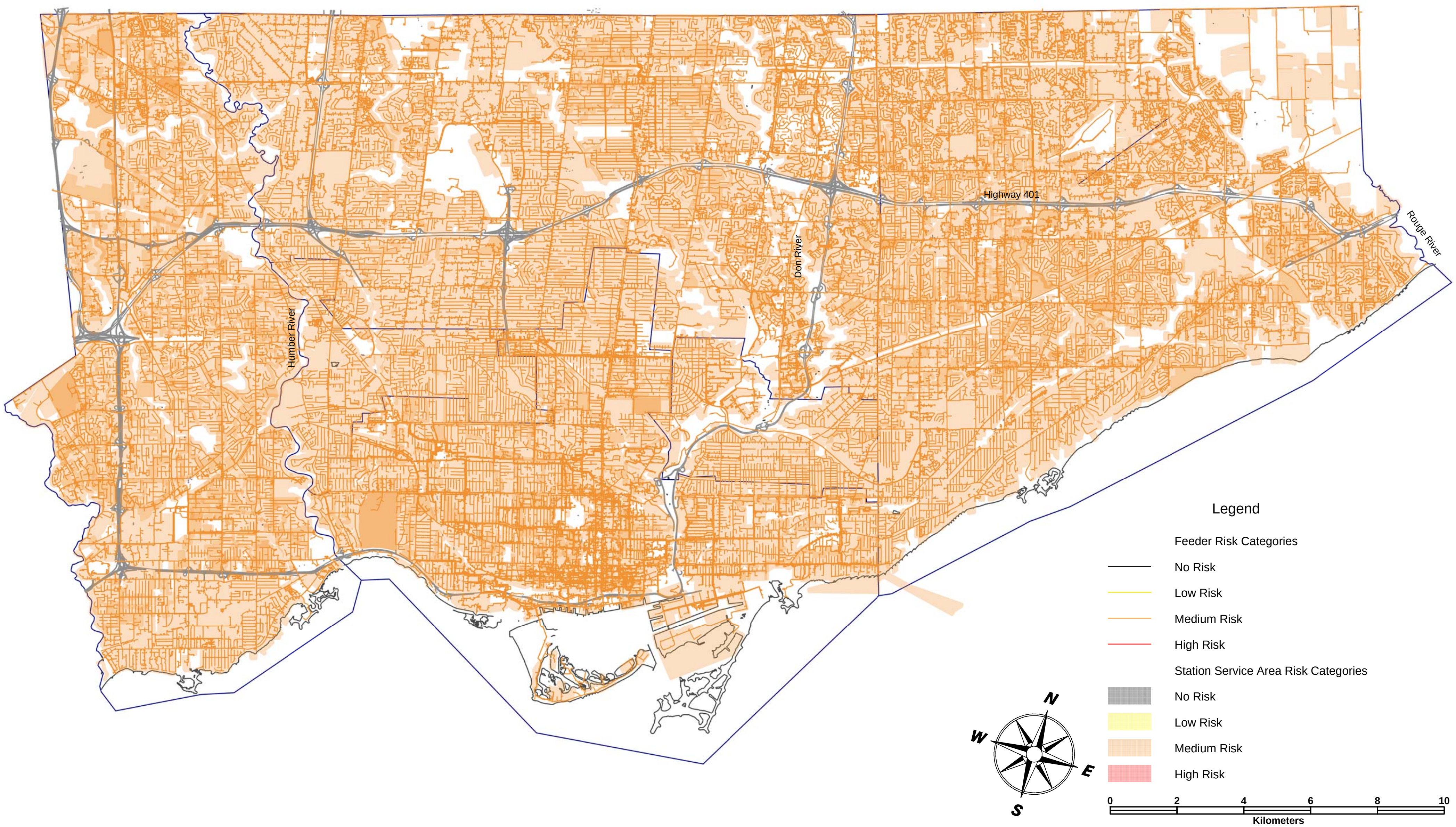
PIEVC Phase 2 Climate Change Risk Map by 2050

5. Average Temperature Above 30 C for 24 Hours



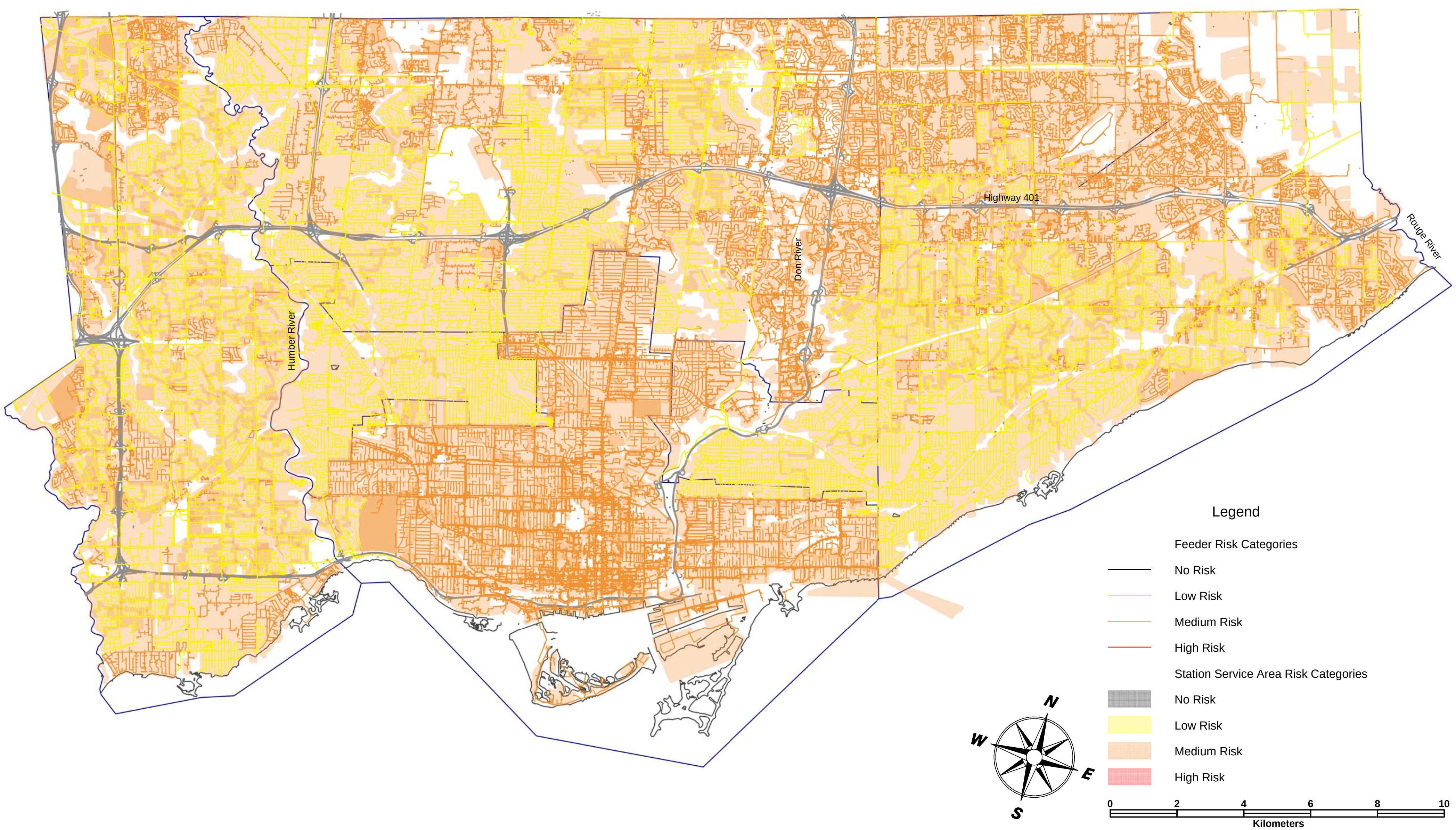
PIEVC Phase 2 Climate Change Risk Map by 2050

6. Heat Wave 3 Day with Maximum Temperature Above 30 C



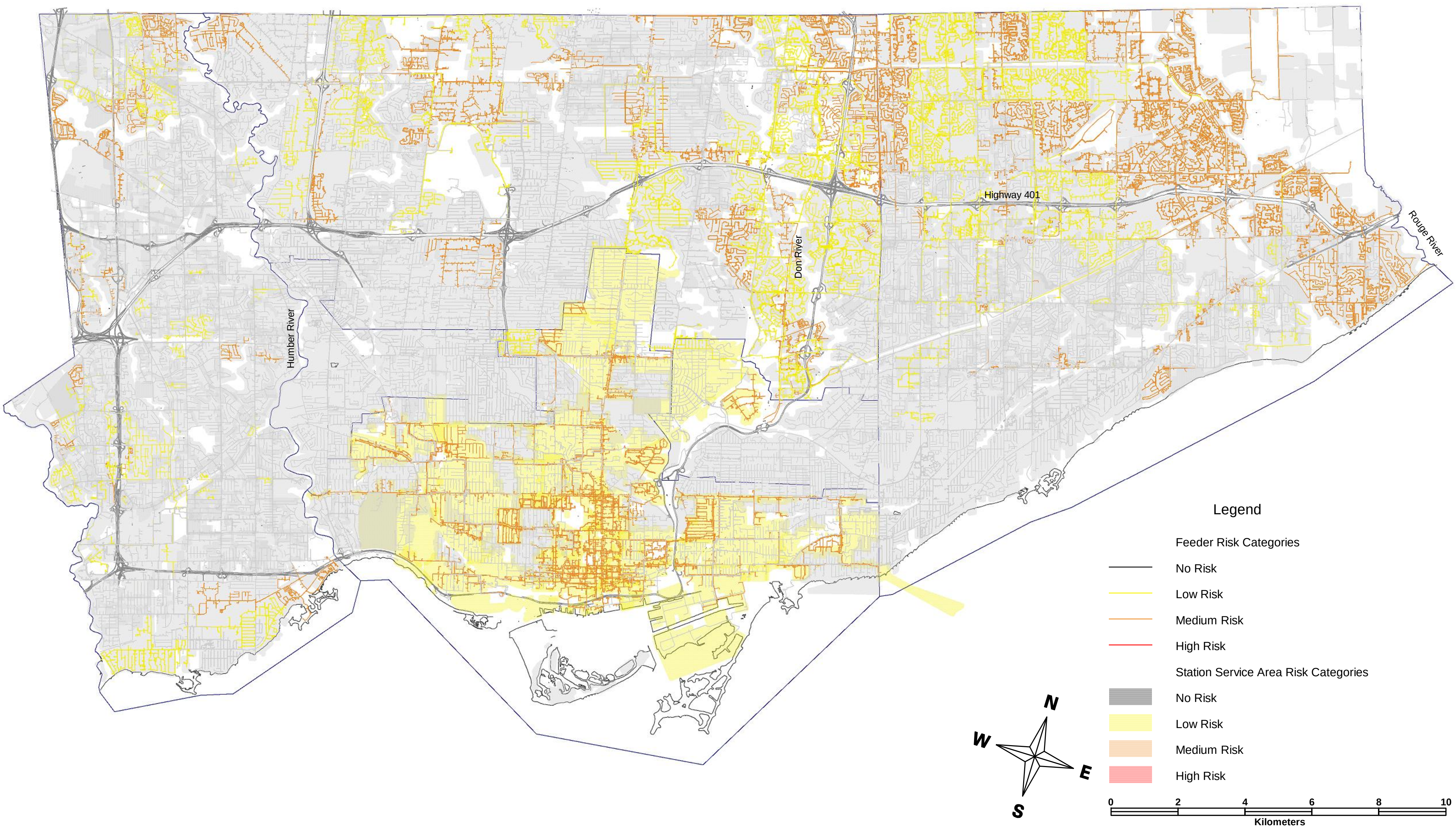
PIEVC Phase 2 Climate Change Risk Map by 2050

7. High Night Time Temperature Minimum Above 23 C



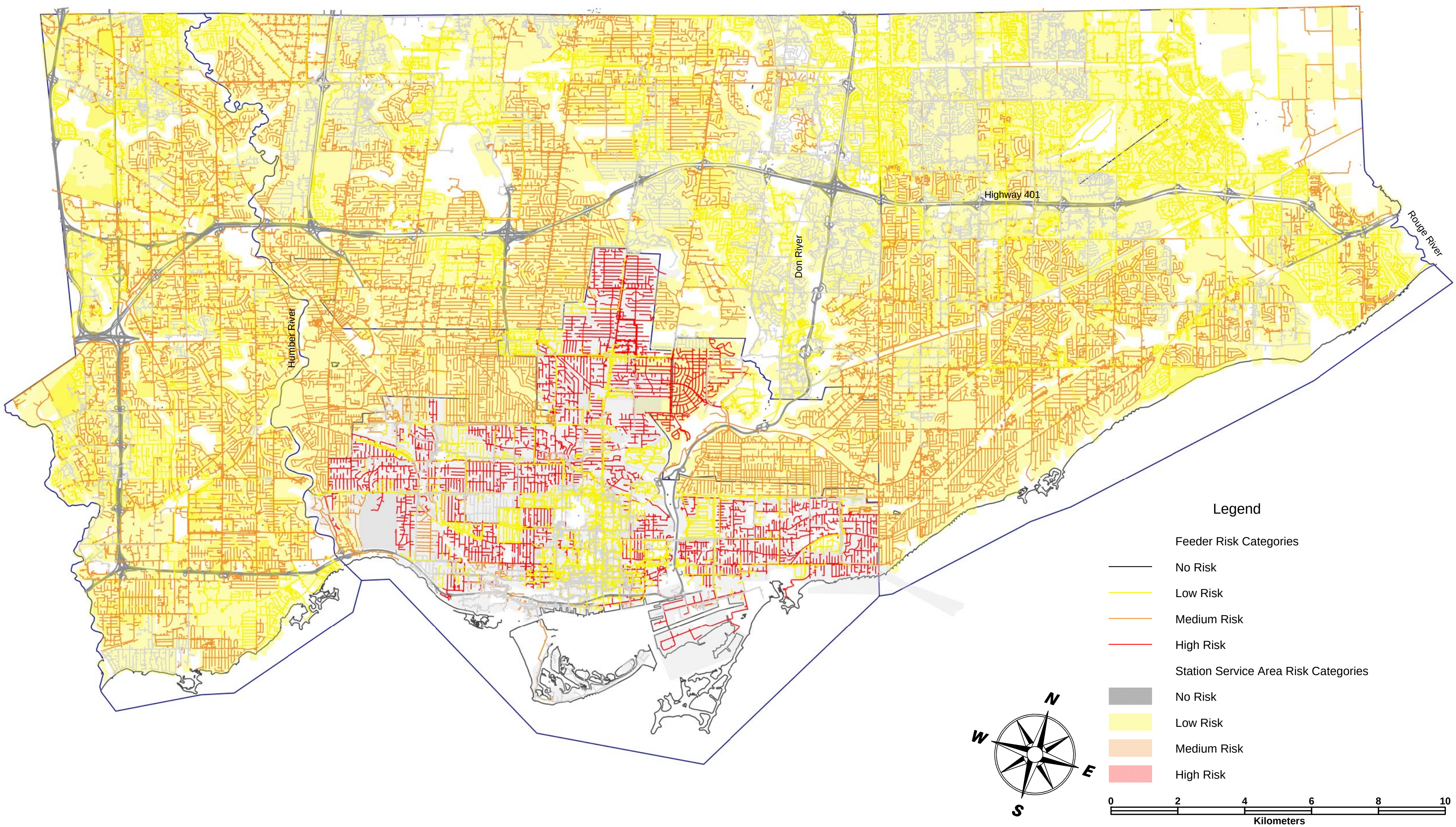
PIEVC Phase 2 Climate Change Risk Map by 2050

8. Extreme Rainfall 100mm in Less than 24 Hours



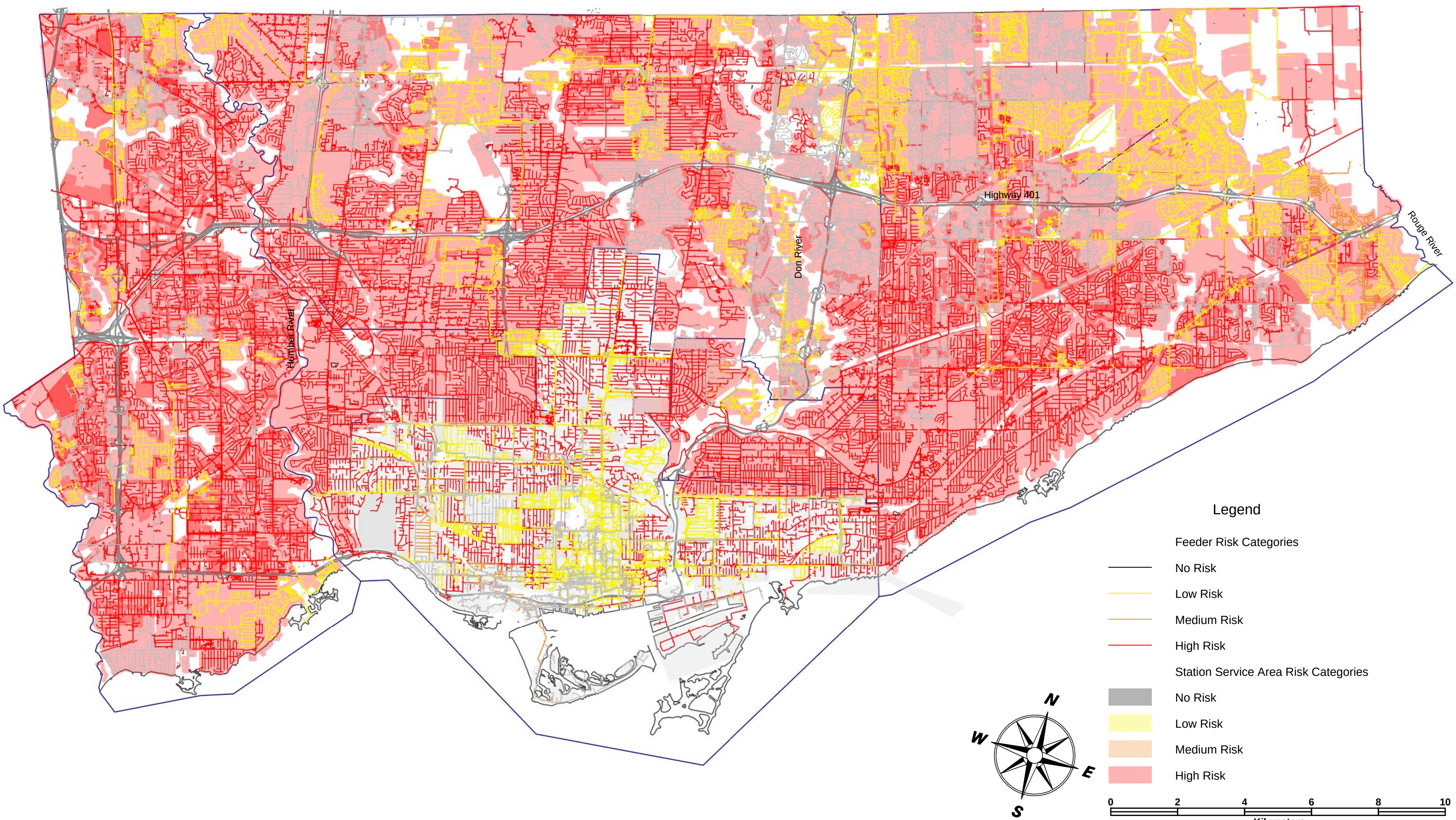
PIEVC Phase 2 Climate Change Risk Map by 2050

9. 15mm Freezing Rain/Ice Storm



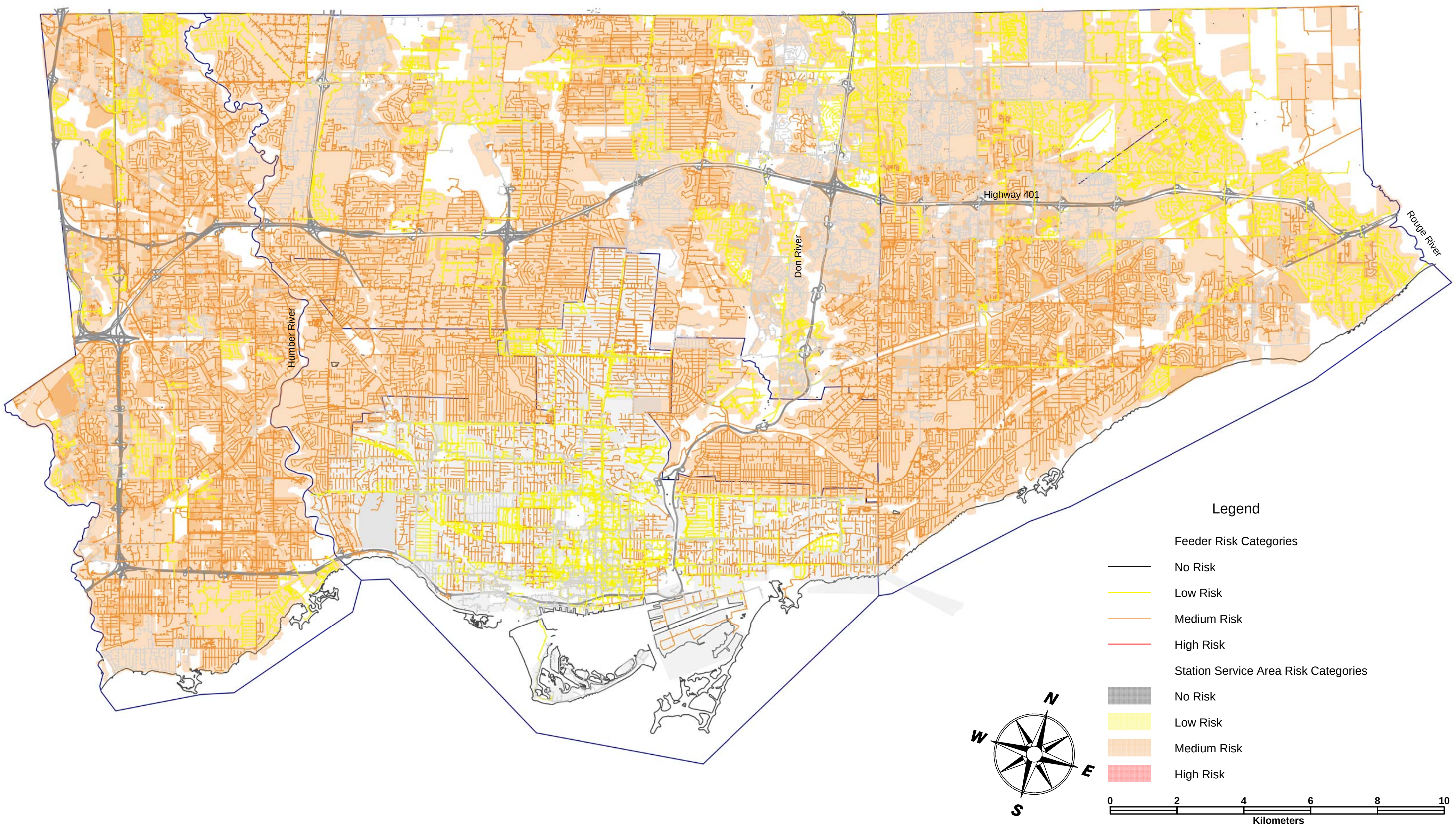
PIEVC Phase 2 Climate Change Risk Map by 2050

10. 25mm Freezing Rain/Ice Storm



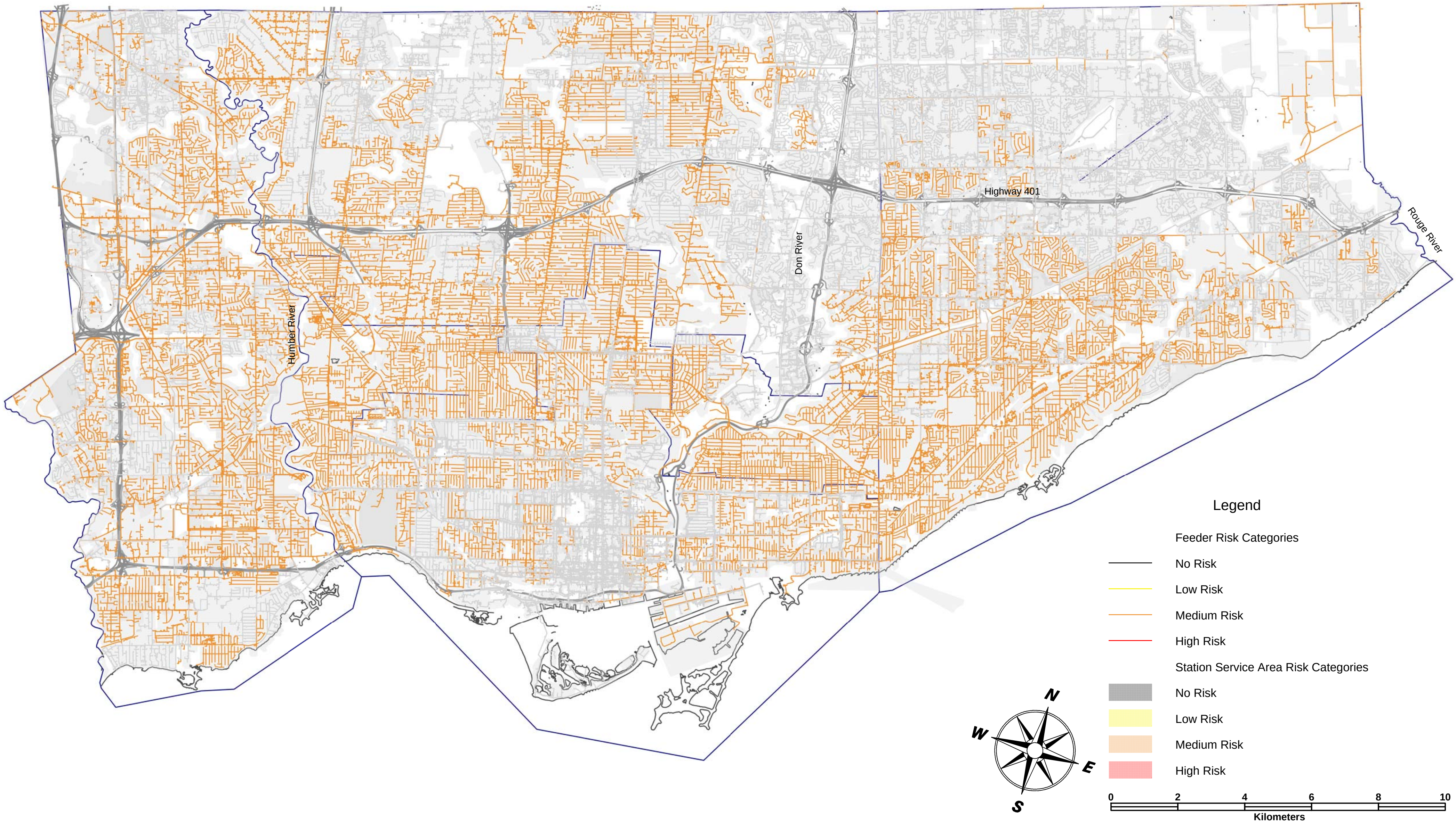
PIEVC Phase 2 Climate Change Risk Map by 2050

11. 60mm Freezing Rain/Ice Storm



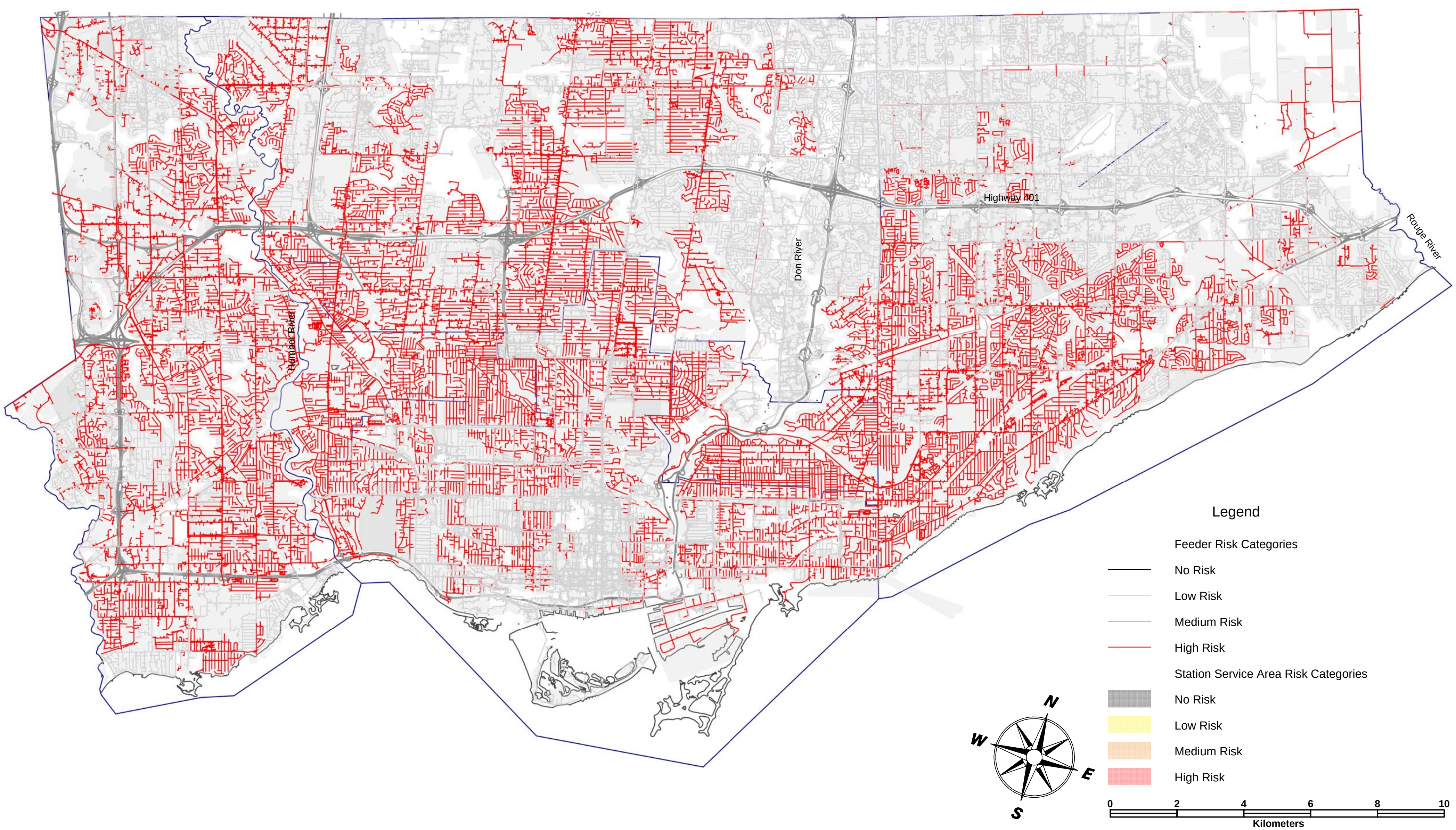
PIEVC Phase 2 Climate Change Risk Map by 2050

12. High Winds Greater Than 70km/h



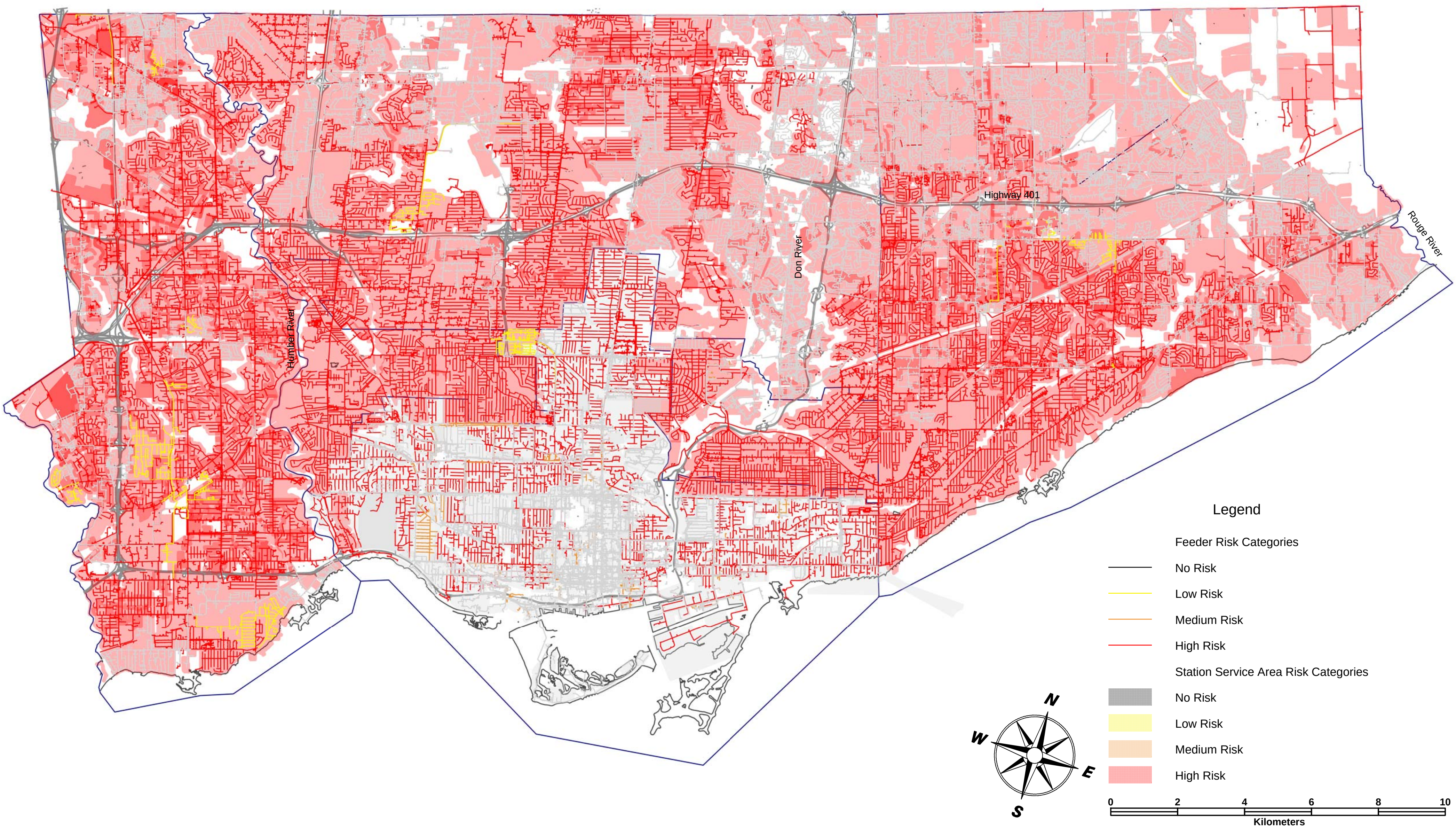
PIEVC Phase 2 Climate Change Risk Map by 2050

13. High Winds Greater Than 90km/h



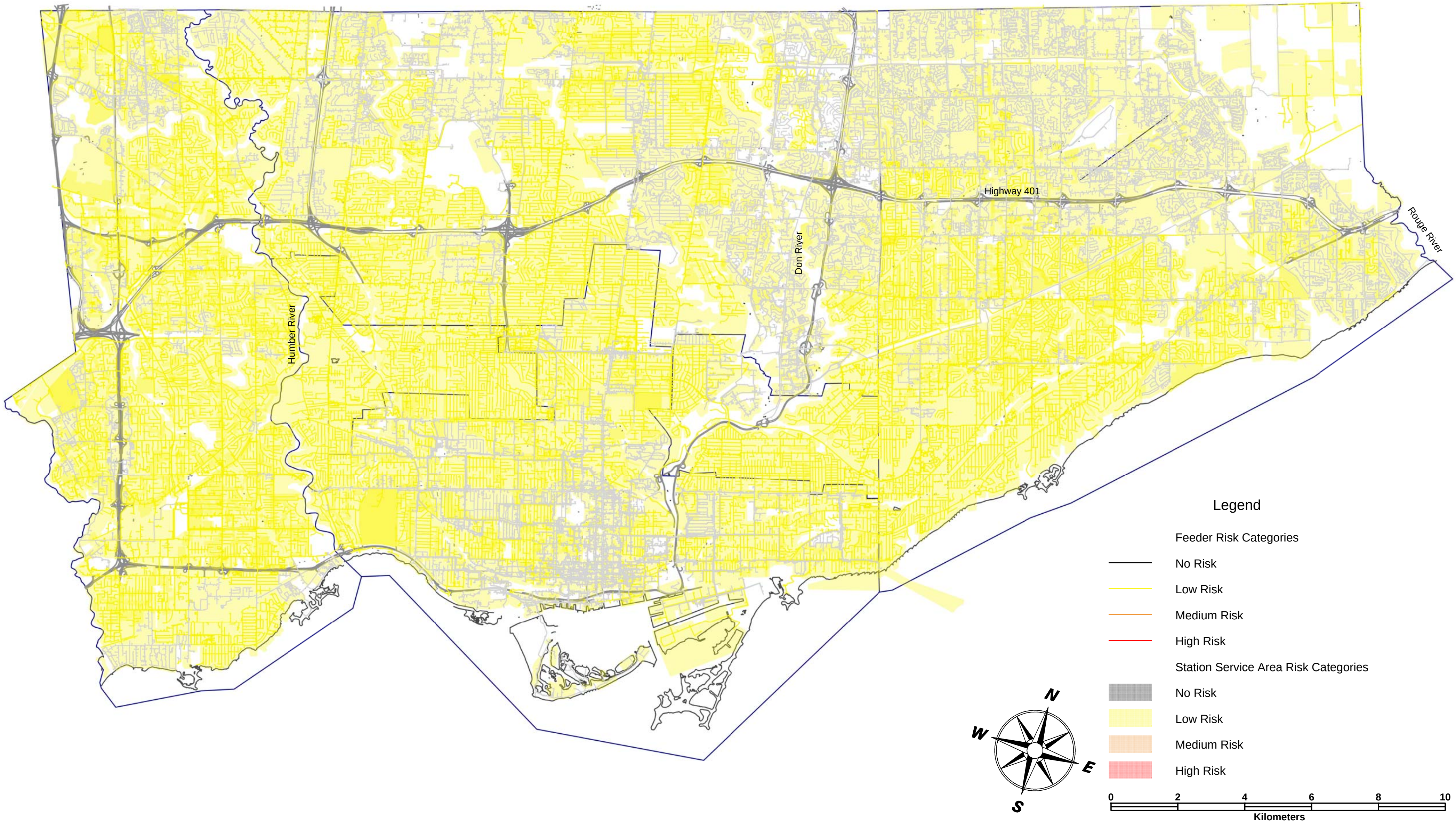
PIEVC Phase 2 Climate Change Risk Map by 2050

14. High Winds Greater Than 120km/h



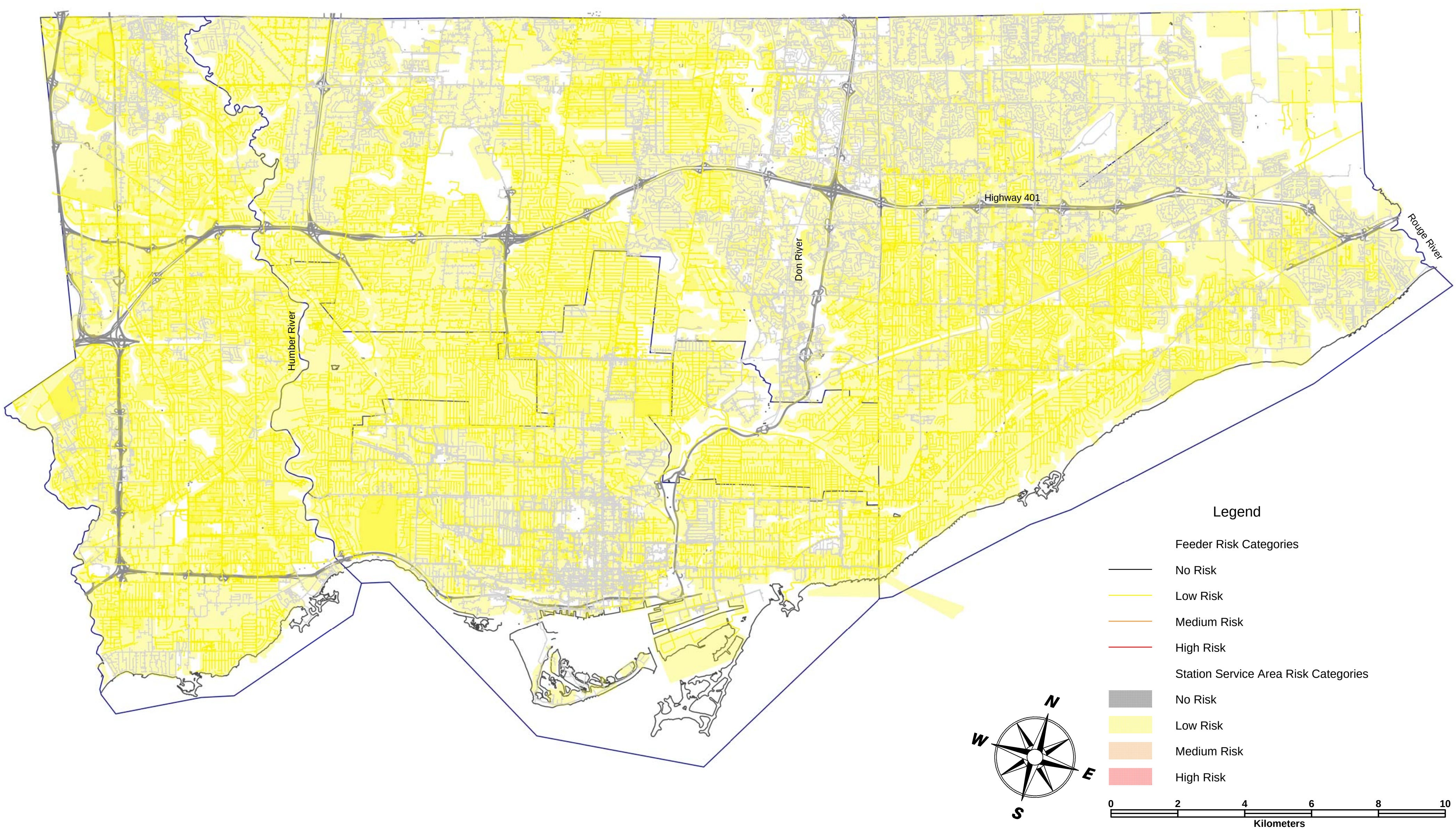
PIEVC Phase 2 Climate Change Risk Map by 2050

15. Tornadoes EF1+



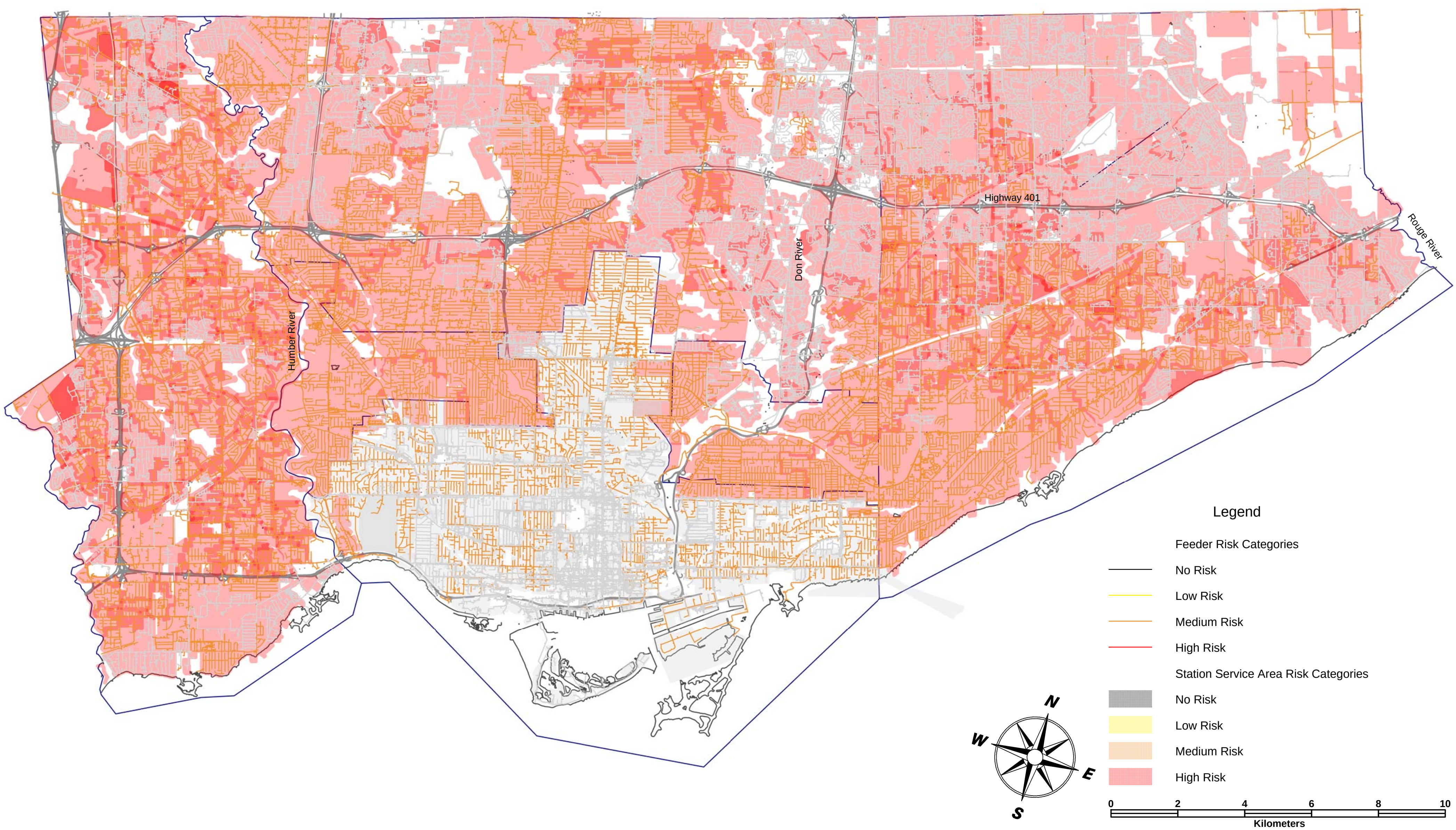
PIEVC Phase 2 Climate Change Risk Map by 2050

16. Tornadoes EF2+



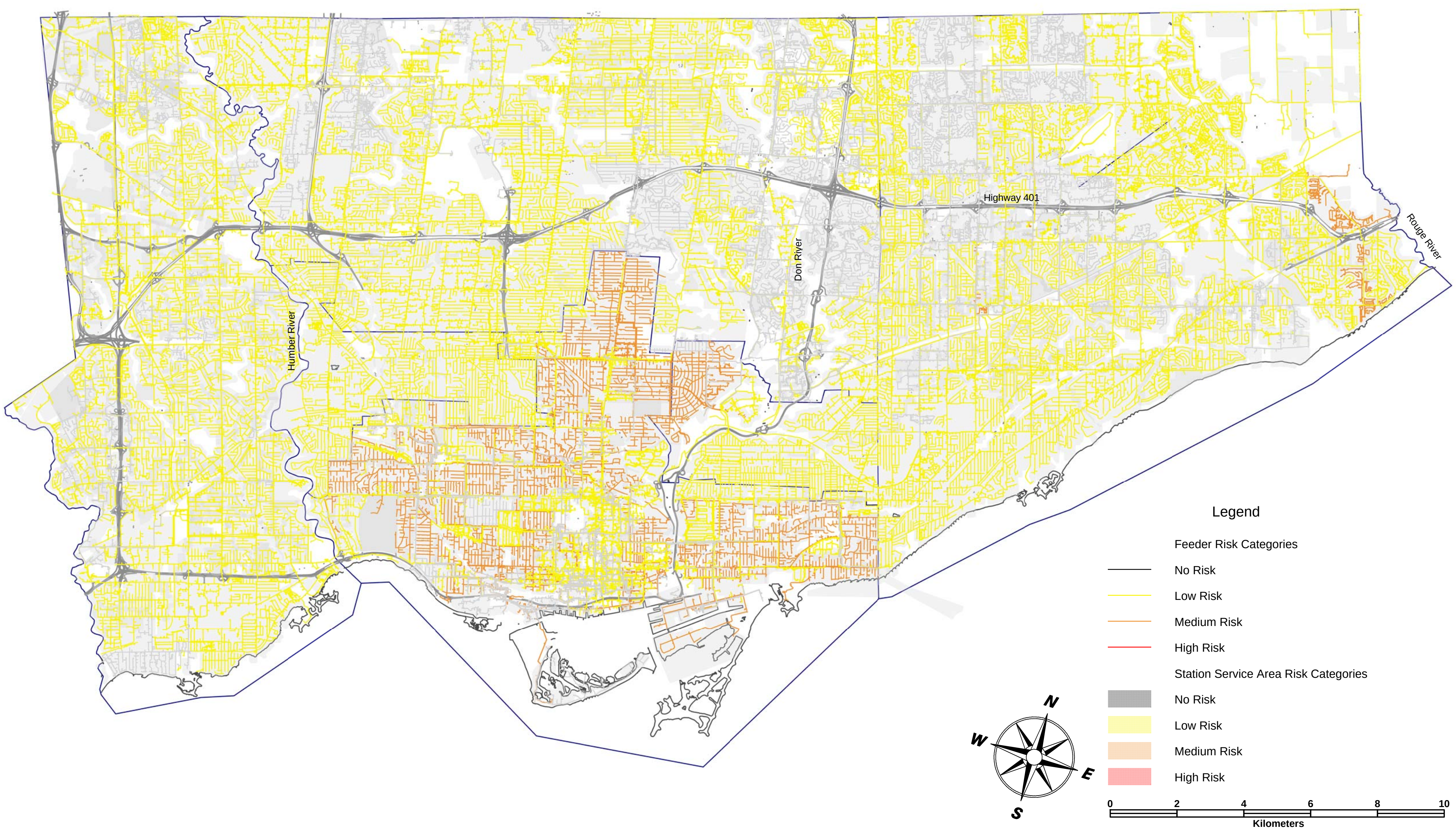
PIEVC Phase 2 Climate Change Risk Map by 2050

17. Lightning



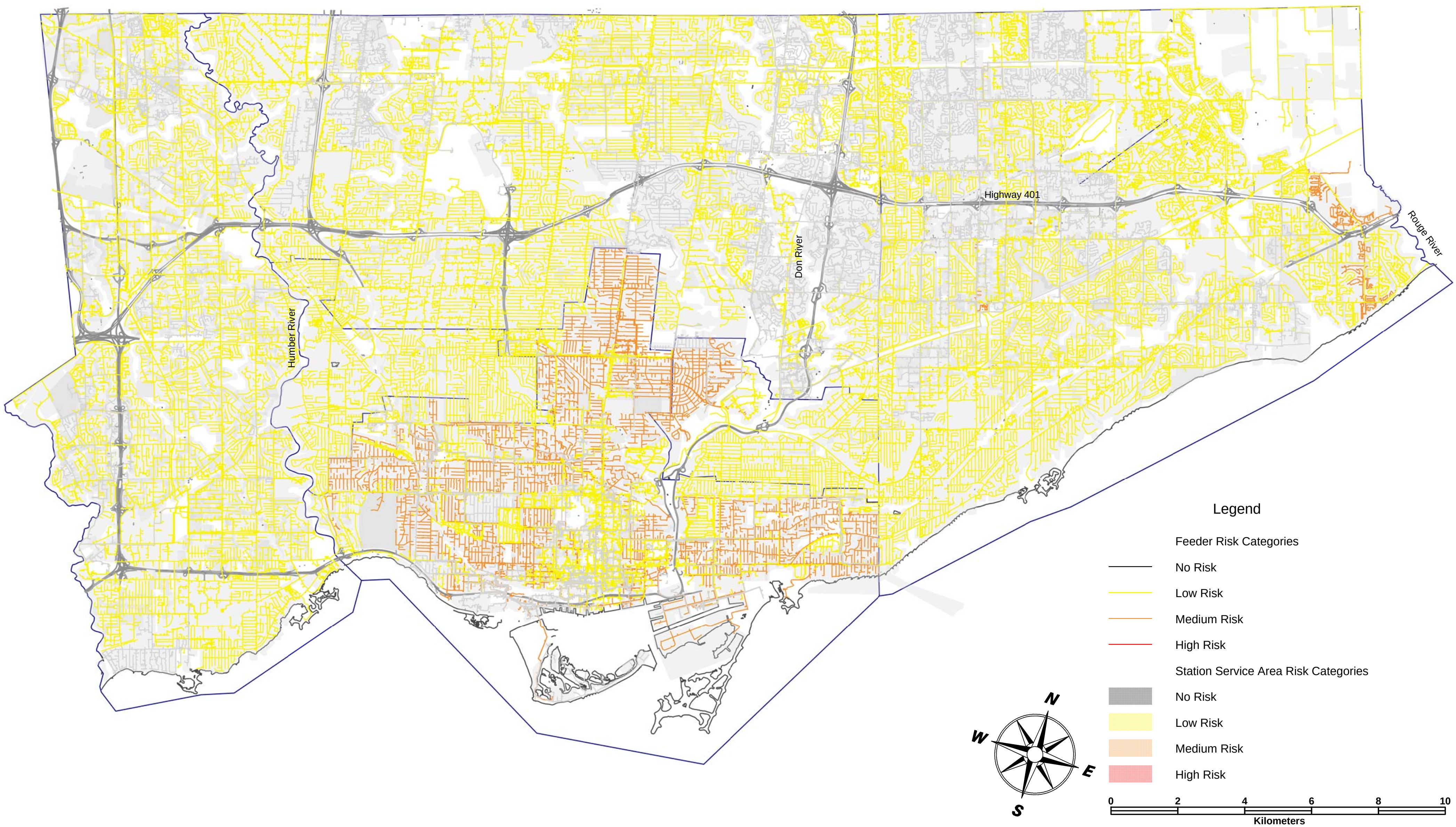
PIEVC Phase 2 Climate Change Risk Map by 2050

18. Snow >5cm



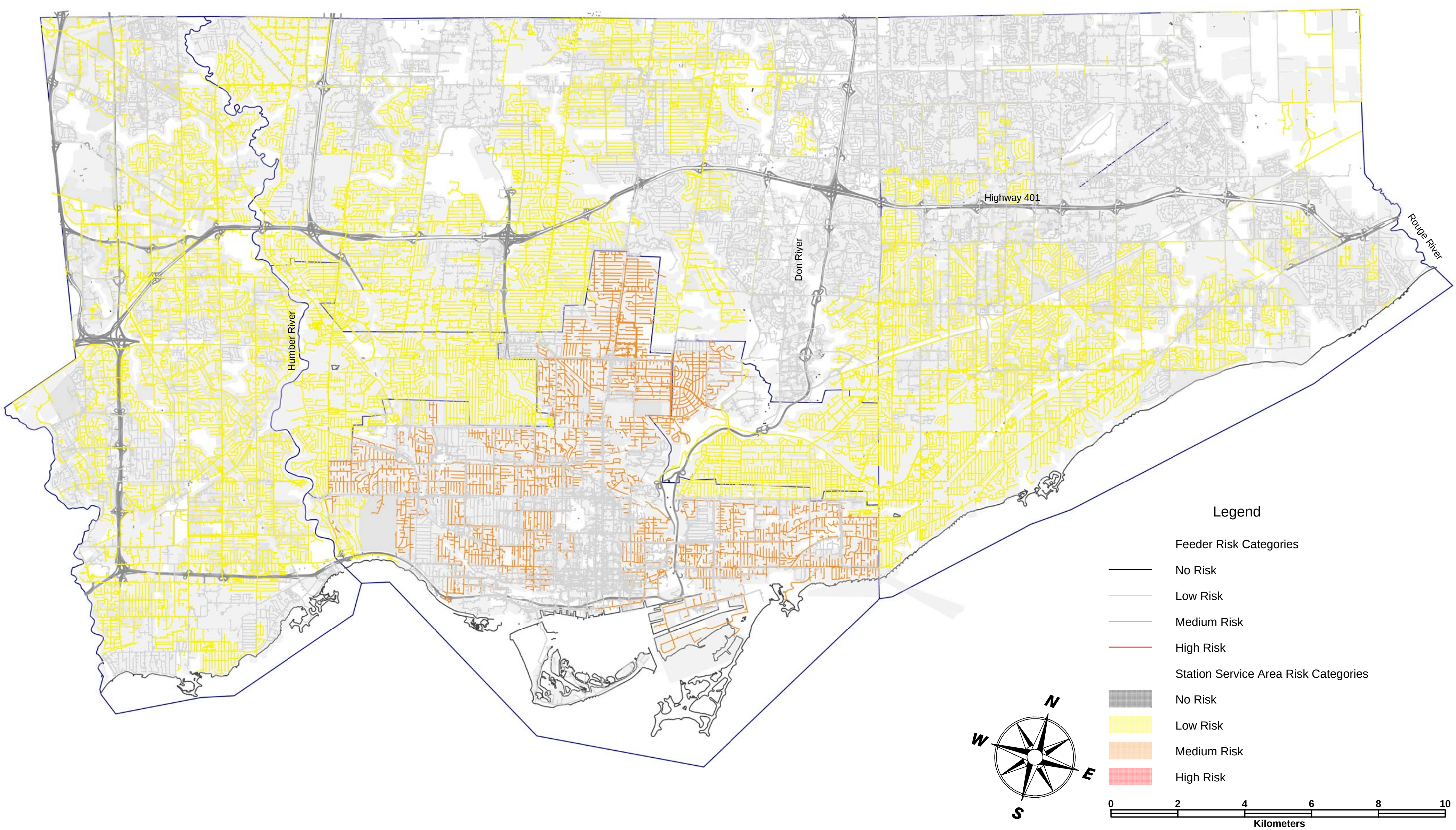
PIEVC Phase 2 Climate Change Risk Map by 2050

19. Snow >10cm



PIEVC Phase 2 Climate Change Risk Map by 2050

20. Extreme Cold Weather



Appendix F
Load Projection Methodology – Toronto Hydro

This information has been removed from the public version of this report

Appendix G
Engineering Analysis

Worksheet 4

The following appendix provides details about the estimation and calculation of the various load and capacity factors used in the Engineering Assessment of medium risk climate/infrastructure interactions. AECOM has elected to present this material in the following section in lieu of worksheet 4 template of the PIEVC Protocol.

1.1 Engineering Analysis Method

The engineering analysis is presented according to the following structure:

1. # Climate parameter / infrastructure system or component

Results and consequences: a recapitulation of the risk scoring results (scores range from 1 to 49) and consequences from Protocol Step 3, risk assessment activity

Task 1: Total Load: The total projected load, L_T, is the sum of three load parameters, $L_E + L_C + L_O$

L_E = Existing load.
L_C = Changing climate load placed on the infrastructure components for the project time horizon (2030 – 2050).
L_o = Other projected change loads.

Task 2: Capacity: The total projected capacity, C_T is the sum of three parameters, $C_E - C_{\Delta E} + C_A$

C_E = Existing capacity.
$C_{\Delta E}$ = Projected change (loss) in capacity arising from aging and normal wear and tear of the infrastructure components
C_A = Other projected additional capacity

Task 3: Vulnerability ratio: When possible, the vulnerability ratio is calculated

$$V_R = \frac{L_T}{C_T}$$

→ When $V_R > 1$, the infrastructure component is vulnerable

→ When $V_R < 1$, the infrastructure component has adaptive capacity

Task 4: Capacity Deficit: When the infrastructure is considered vulnerable, the projected capacity deficit, C_D is calculated, where possible. $C_D = L_T – C_T = L_T – (C_E + C_{\Delta E} + C_A)$

Task 5: Conclusions from the Engineering Analysis: A statement is made as to whether the climate parameter-infrastructure interaction should be passed to Step 5 of the Protocol (i.e. making a recommendation to mitigate a vulnerability) or need not be considered further due to resilience to climate change.

When the engineering analysis cannot be completed, data gaps and possible types of additional studies are described that would facilitate the assessment of infrastructure vulnerability.

1.2 Resiliency or Vulnerability Evaluation

1. High temperature above 25°C and above 30°C / Transmission and Municipal stations and all Temperatures / Protection and Control systems

- **Results and consequences**: Risk scores of 14 and 21 depending on station excess capacity rating. Batteries lifespan is reduced. They are vital components because they are used as back-up power in case of power outages and emergencies and supplied DC current to many equipment in the stations.

- **Load**

$\mathbf{L_E}$ = Continuous loads (e.g. lighting) + Noncontinuous loads (e.g. fire protection systems) + Momentary loads (e.g. switchgear operations). A margin of 10-15% can be applied by the designer. Also the battery's rated capacity should be at least 125% (1.25 aging factor) of the load expected of its service life (IEEE-Std-485, 1997).

$\mathbf{L_C}$: Same loads will apply. Ventilation may be a little bit higher because of higher temperatures but the load will not change drastically.

$\mathbf{L_o}$: No other load to consider

$L_T = L_E + L_C + L_O = L_E + xL_E + 0$, where x is very small. Approximation: $L_T = L_E$

- **Capacity**

$\mathbf{C_E}$: The batteries are designed to operate at a temperature of 25°C. They are not installed in a temperature controlled room.

$\mathbf{C_E}$ capacity at 25°C = 100%. Expected service life = 25 years
The end of life of a battery is considered to be at 80% of its capacity (IEEE 485).

$\mathbf{C_{\Delta E}}$: Battery capacity at higher temperatures will actually increase if the cells are designed for a capacity of 100% at 25°C. From IEEE (IEEE-Std-485, 1997), "If the lowest expected electrolyte temperature is above 25 °C (77 °F), it is a conservative practice to select a cell size to match the required capacity at the standard temperature and to recognize the resulting increase in available capacity as part of the overall design margin". However, sustained high ambient temperatures result in reduced battery lifetimes.

$\mathbf{C_{\Delta E}}$ capacity over 25°C: more than 100%. Expected Service life will be less than 25 years. From Toronto Hydro's experience, some batteries have only lasted 10 years when they were expected to last 25 years.

$\mathbf{C_A}$: Battery designs are maintained at 100% capacity at 25°C.

$C_T = C_E - C_{\Delta E} + C_A = C_E – (-xC_E) + 0 = (1+ x)\ C_E$, but expected lifetime decrease.

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{Le}{(1+x)Ce} < 1 \; but\; life\; expenctancy\; decrease$$

- **Conclusion: Yes. Further action recommended.** Under higher temperatures, batteries will continue to be able to supply the necessary power to operate equipment (e.g. lighting, fire protection systems, switchgears). However, battery life may continue to be shorter than expected. Toronto Hydro has already encountered this problem, as batteries with a lifespan of 25 years are being replaced after 10 years.

2. High temperature above 35°C / Transmission stations

- **Results and consequences**: Risk scores of 21 and 28 depending of station excess capacity rating. Power transformers may be overloaded.

- **Load**

$\mathbf{L_E}$ = Maximum coincident load (year of design) + % of contingency at ambient temperature of 30°C
The actual peak load of the area is around 5 000 MVA.

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase caused to higher consumption of clients = bL_E

$\mathbf{L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E}$

- **Capacity**

$\mathbf{C_E}$: Horseshoe area station power transformer capacity is considered maximum with 100% of its total capacity at 30°C average ambient, and hottest point within power transformers not exceeding 110 °C. For Former Toronto area, the station capacity is restricted to no more than 95% of its total capacity because there are no station ties among transformer stations.
Expected service life = 20.55 years (180 000 hours).
Toronto Area transmission stations installed capacity is around 7 550 MVA.

$\mathbf{C_{\Delta E}}$: x%, where x is less than 100. According to IEEE (IEEE-Std_C57.91, 2012) the associated maximum air temperature should not be more than 10°C above the average ambient air temperature for air-cooled transformers (40°C). Station capacity at higher temperatures (e.g. 35°C) will be lower than at design temperature (30°C ambient) because the hottest point within power transformers has to be maintained below 110°C. Same expected service life if the load is adjusted (i.e. decreased) to meet these temperature restrictions. There x% at maximum temperatures above 35°C will not be large.

$\mathbf{C_A}$: Additional capacity will depend on the station. Some transmission stations will have added capacity by the end of the study period due to planned or anticipated upgrades, while others will not. The added capacity was evaluated within the risk assessment. “Good” rating mean that the transmission stations will have a greater future capacity margin, while “moderate” and “low” ratings mean stations will have less of a future capacity margin. From an overall systems standpoint, the worst case scenario is equivalent to no additional capacity added.

$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E – (xC_E) + 0 = (1 - x) C_E}$ **= Approximation** $\mathbf{C_T \approx C_E}$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a+b)Le}{Ce} = \frac{Load\ growth\ rate\ \times 5000\ MVA}{7550\ MVA}$$

Value of (1+ a + b) = Toronto Hydro could estimate a mean load growth rate for the study period.

- **Capacity deficit**

$\mathbf{C_D = L_T – C_T = (1 + a + b) L_E – (1\text{-}x) C_E}$.

The capacity deficit can’t be calculated because the load growth rate for the study period is not known.

- **Conclusion: Additional study recommended, conclusions for high temperature and power transformers also apply (see Chapter 7).** Transmission station designers will need to take into account the significant increase in days with maximum temperatures above 35°C, which reduces station capacity while, on the other hand, experiences an increased load demand. At the moment, no load growth rate for the period of this study was estimated. This could be calculated in further studies. The recommendations given in Chapter 7 for transmission stations and maximum temperature above 40°C / average temp above 30°C apply to this interaction.

3. High temperature above 40°C and Average temperature > 30°C / Transmission stations

- **Results and consequences**: risk score of 35 for transmission stations which have good future capacity (excess capacity) in the Horseshoe Area. Transmission stations with low future capacity ratings scored a high risk. Power transformers will be overloaded.

- **Vulnerability Ratio:** Refer to parameter #2.

- **Conclusion: Further action recommended**. Most of the transmission stations considered in this study were judged to be vulnerable (high risk rating) to high temperatures. The stations in the Horseshoe received a medium-high risk score (35) due to the application of the concept of excess capacity, which is qualitative and notional (refer to the **Appendix F**). As such, it is recommended that transmission stations receiving a medium-high risk score be considered vulnerable to extreme high temperatures as part of a consistent pattern of risk. This will also help Toronto Hydro to adopt a consistent approach in the design, operations and maintenance of stations.

4. Heat wave (+30°C) and High nighttime temperatures (+23°C) / Transmission stations

- **Results and consequences**: risk rating of 21, 28 and 35 depending of station capacity rating by 2050. Power transformers may be overloaded.

- **Load**

$\mathbf{L_E}$ = Maximum coincident Load (year of design) + % of contingency at ambient temperature of 30°C

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase caused to higher consumption of clients = bL_E

$\mathbf{L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E}$

- **Capacity**

$\mathbf{C_E}$: Horseshoe area station power transformer capacity is considered maximum with 100% of its total capacity. For Former Toronto area, the station capacity is restricted to no more than 95% of its total capacity because there are no station ties among transformer stations.
Expected service life = 20.55 years (180 000 hours).

$\mathbf{C_{\Delta E}}$: x%, where x is lower than 100. Power transformers can operate at temperature above 30°C, but long periods of high temperature can affect the equipment, such as when night time temperatures are high. The power transformer has no time to cool.

$\mathbf{C_A}$: Additional capacity will depend on the station. Some transmission stations will have added capacity by the end of the study period due to planned or anticipated upgrades, while others will not. The future capacity was evaluated within the risk assessment. “Good” rating mean that the transmission stations will have a greater future capacity margin, while “low” rating means stations will have less of a future capacity margin. From an overall systems standpoint, the worst case scenario is equivalent to no additional capacity added.

$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + 0 = (1 - x)\, C_E}$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a+b)Le}{(1-x)Ce} = \frac{Load\ growth\ rate\ \times 5000\ MVA}{(1-x)7550\ MVA}$$

Value of (1+ a + b) = Toronto Hydro could estimate a mean load growth rate for the study period.

Value of (1-x) = The loss of capacity is highly variable. It will not only depend of the maximum temperatures but also of the minimum temperatures. If the minimum temperature stays high during many days the power transformers will have no time to cool and its capacity will have to be reduced. High nighttime is important in that sense.

- **Capacity deficit**

$\mathbf{C_D = L_T – C_T = (1 + a + b)\ L_E – (1\text{-}x)\ C_E}$.

The capacity deficit cannot be calculated because the load growth and the loss of capacity are not known.

- **Conclusion: Additional study recommended, conclusions for high temperature and power transformers also apply (see Chapter 7).** Consecutive days with high temperatures and high night time will increase over the study period. For example, high nighttime temperatures will go from 0.7 day/year to 7 days/year in 2030 to 16 days/year in 2050. Power transformers are vital equipment in the distribution of electricity and high temperatures have a significant impact on the capacity of the transformers. For these reasons, the conclusion of this report for temperature above 40°C and for high daily average temperature>30°C are also relevant to the heat wave and high nighttime temperature parameters. A load growth rate could be calculated for a better evaluation of impacts.

5. Freezing Rain/Ice Storm 60 mm ≈ 30 mm radial (major outages) / Transmission stations and Municipal stations

- **Results and consequences**: risk rating 28
  Outgoing lines (overhead) could fall down

- **Load**

$\mathbf{L_E}$ = Actual load is equal to the actual number of days of freezing rain

$\mathbf{L_C}$ = The load due to the freezing rain will slightly increase, $\mathbf{L_C}$ = a$\mathbf{L_E}$**,** where ''a'' is a % of increase (small)

$\mathbf{L_o}$ = N/A

$\mathbf{L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E} \rightarrow \mathbf{L_T > L_E}$

- **Capacity**

$\mathbf{C_E}$: The overhead power lines in the Toronto area are designed based on the CSA standard 22.3. Loads and load combinations correspond to so-called "Heavy Loading" specified in Table 30 of the CSA standard: wind of 400 Pa, 12.5 mm ice, -20°C temperatures.

$\mathbf{C_{\Delta E}}$: It is assumed that the capacity will remain the same if the design criteria are not changing. $\mathbf{C_{\Delta E}}$ = **0**

$\mathbf{C_A}$: N/A

$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E}$

- **Vulnerability Ratio**

$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{Ce} > 1$, the infrastructure is vulnerable

- **Capacity deficit**

$\mathbf{C_D = L_T – C_T = (1 + a)\ L_E – C_E}$.

- **Conclusion: Further action recommended.** The probability of occurrence of a heavy freezing rain event of 60 mm is relatively low in the future (8 – 25% probability of occurrence over the 35 year study period). However, this this interaction is part of a similar pattern of vulnerability as 25 mm freezing rain events (design capacity). Therefore, solutions for 25 mm events also relevant to mitigating heavy freezing rain events of ~ 60 mm.

6. High temperature (+35°C,+ 40°C, average temperature > 30°C, heat wave, high nighttime temperatures) / Municipal stations

- **Results and consequences**: 21, 28, 35. Medium to high medium risks.
  Consequences: Power transformers may overload.

- **Load & Capacity:** Same assumptions as for the power transformers in the transmission stations.
  The load will increase because of warmer temperatures. The capacity will decrease because of power transformers low ability to withstand hot temperatures for extended periods.
  Added capacity: Many Toronto Hydro to Toronto Hydro stations which interconnect the 4.16 kV power lines, will progressively be replaced by converted lines at 13.8 kV. Most of the municipal stations will then be to interconnect voltage levels from 27.6 kV to 13.8 kV. It is assumed that added capacity during the study period will be low for the 27.6-13.8 kV / 4.16 kV stations. More capacity can be added to the 27.6 kV/13.8 kV stations and will be variable depending on the stations need.
  For Toronto Hydro to Private owner ship, added capacity is possible and will be very variable depending on Client's need.

  $L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E$
  $C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + yC_A$ where x is variable and y is small and variable$\rightarrow C_T < C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a+b)Le}{\mathrm{CE} - (\mathrm{xCE}) + \mathrm{yCA}} < 1$$

- **Conclusion: Further action recommended**. High temperature and combinations of high temperature, high average temperature, high nighttime temperature and high load demand will have consequences on the capacity of the power transformers and the cables. For Toronto Hydro to Private ownership stations, a case by case evaluation is recommended.

1.2.1 Underground and Overhead feeders

7. High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime / Underground feeders

- **Results and consequences**: risk ratings 14, 21 and 28. The high demand stresses cables and power transformers. More capacity was available in the horseshoe area giving slightly lower results.

- **Load**

$\mathbf{L_E}$ = Actual demand + % of contingency

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase because of higher electrical consumption of clients (more electronic devices) = bL_E

$\mathbf{L_T = L_E + L_C + L_O}$

- **Capacity**

$\mathbf{C_E}$: Actual design of cables and power transformers is based on the actual load plus a margin. For underground feeders in the dual radial system, feeder capacity equals 50% of load for two parallel feeders. IEC 60287 base maximum ambient temperature at 35°C and maximum ground temperature at 20°C (IEC-60287))

$\mathbf{C_{\Delta E}}$: XLPE cables have an expected life of 40 years (for concrete duct installations) and for PILC cables 75 years. These cables are today reaching their expected life because they were installed during the early 1900s (for PILC) and 1950s (for XLPE). They will be changed through testing or from failure, because even if the cables are old they could be still being in good conditions (Toronto Hydro - OM&A, 2014). However, with climate changes (higher temperature), these cables will be stressed more often. Aging processes will accelerate and reduce capacity. This is a highly variable factor and cannot easily be calculated.

$\mathbf{C_A}$: Added capacity will be done by Toronto Hydro. Underground planning group could estimate the projected capacity for the study period.

$\mathbf{C_T = C_E - C_{\Delta E}\ ?\ + C_A}$

- **Conclusion: Further action recommended.** The vulnerability ratio and the capacity deficit cannot be calculated because the projected load on cables is not known. However, it is projected that climate change related high temperatures could create higher demand for cooling, and may place greater stress on cables and lead to increasing occurrences of cable failures. Therefore, high heat impacts on cable was deemed to be a vulnerability.

8. Extreme rainfall / Underground feeders

- **Results and consequences**: risk rating of 12, 18, 24, 30
    a. Feeders: Water treeing of the cables, flooding (18-24);
    b. Nun-submersible equipment failure in vault type stations below ground (30 Horseshoe Area, 36 Former Toronto);
    c. Above ground stations, access could be limited (12);
    d. Network feeders: old N/W protectors are not submersible (30).

a. Feeders: Water treeing of the cables, flooding (18 Horseshoe Area, 24 Former Toronto)

Water treeing refers to a partially conductive structure that may form, in the presence of water, within the polyethylene dielectric used in buried high voltage cables. […] Water trees begin as a microscopic region near a defect. They then grow under the continued presence of a high electrical field and water. Water trees may eventually grow to the point where they bridge the outer ground layer to the center high voltage conductor, leading to complete electrical failure at that point (Wikipedia).

- **Load**

$\mathbf{L_E}$ = Actual demand + % of contingency

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase due to higher electrical consumption by clients (more electronic devices)= bL_E

$\mathbf{L_T = L_E + L_C + L_O}$

- **Capacity**

$\mathbf{C_E}$: Actual design of cables is based on the actual load plus margin. For the underground feeders in the dual radial systems, each feeder capacity is equal to the load x 2.

$\mathbf{C_{\Delta E}}$: Flooding and heavy soil moisture tends to reduce the dielectric strength of cables. This cannot be calculated as it is highly variable. *The aging mechanism of underground cables depends on factors that involve the cable characteristics, accessory characteristics, and operating conditions, different power cable systems will age in different ways. In fact, aging degradation, and failure mechanisms are statistical in nature.* (NEETRAC, 2010)

$\mathbf{C_A}$: Toronto Hydro shall have a planning procedure for increasing the capacity of their underground system in line with load growth.

- **Conclusion: Further action recommended.** The load can be calculated by Toronto Hydro's estimates. However, the capacity is very hard to define, as aging degradation depends on many factors. Nonetheless, in combination with high heat events, extreme rainfall impacts on underground cables was deemed a vulnerability.

b. Non-submersible equipment failure in vault type stations below ground in the Horseshoe Area (30) (Former Toronto has a high risk result)

- **Load**

L_E = 0.04 flood per year (over 100 mm + short duration).

L_C = 0, flood intensity is considered to be the same for a given event (100 mm rainfall), but it will occur with greater frequency. Another complicating factor is how local drainage conditions (area topography, sewer system changes, land use changes) may or may not change flood characteristics in below ground vaults. At the scale of the current study, site specific flooding characteristics are not considered.

L_o = N/A

$L_T = L_E + L_C + L_O$ = L_E.

- **Capacity**

C_E: Cannot work when flooded. Most of the vaults have pumps when they are deeper than the city sewers. Small shallow single phase vaults drain naturally to the sewers. Pumps usually work well. There is no specific information available on the capacity of the pumps, but they are assumed to function correctly, as there are no indications that pump capacity needs to increase.

$C_{\Delta E}$: same as today. $C_{\Delta E} = C_{E1} - C_{E2} = 0$.

C_A: No additional capacity required.

$C_T = C_E - C_{\Delta E} + C_A = C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{Le}{Ce} = 1$$

Conclusion: Further action recommended. Without replacement of non-submersible equipment by submersible equipment, the performance of electrical equipment in below grade vaults will not change over time (i.e. non-functional when flooded) The planned conversion of non-submersible equipment to submersible types in flood prone areas will help reduce vulnerability. While Toronto Hydro is gradually replacing vault type non-submersible equipment with submersible versions, non-submersible vault type equipment is likely to remain in the system over the study period, and hence remain a vulnerability for Toronto Hydro.

c. Above ground stations, access to the station and to the station equipment could be limited due to localized flooding of streets around the station, or at the station itself

- **Results and consequences** Low –medium risk.
- **Conclusion: No further action required.** This impact does not relate to station load or capacity. The consequence is that the access to the vault stations or the stations equipment could be temporarily impeded. Impact is localized and temporary, and was not judged to warrant further action beyond current practices.

d. Network feeders: old N/W protectors are not submersible (30)

- **Conclusion: Additional Study Recommended.** The old N/W protector may not operate properly if flooded. A network protector automatically connects and disconnects its power transformer from the network when the protector relay detects that power starts flowing in a reverse direction, preventing back feed, which is a potential safety hazard. However a failure of the N/W protector will not mean an interruption to the customer, since network systems are highly redundant. Network protectors are overhauled on a three-year cycle.

  Installations of new N/W protectors are submersible but there are still many old N/W protectors in the systems, particularly in downtown. Further study could be undertaken to evaluate the cost of replacing old network protectors prior to the end of their expected lifecycle against the frequency and impact of old N/W protectors being flooded.

9. High winds (120 km/h) / Padmount stations on distribution network (Former Toronto)

- **Results and consequences**: risk rating 14. Flying debris could impact the equipment.

- **Vulnerability Ratio:** The consequence of high winds and structural loads from flying debris are difficult to establish in terms of the load and the capacity of padmount stations. It's an independent impact based on a statistical probability.

- **Conclusion: No further action required.** The damaged equipment will result in an overall or some loss of service capacity and function. However, it is judged that flying debris is too much of a random occurrence to warrant further action.

10. High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave / Overhead power lines (radial and loop)

- **Results and consequences**: risk ratings of 14, 21, 28, 35
  These 4 climate parameters have the same consequences: Overload of the ONAN power transformers and the overhead conductors.

- **Load**

L_E = Max load + % of contingency

L_C = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

L_o = Load will increase because of load growth due to population growth = bL_E

$$L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E$$

- **Capacity (ONAN power transformers)**

C_E: 100% at 30°C average ambient + hottest point within transformer not exceeding 110 °C.

$C_{\Delta E}$: x%, where x is lower than 100. Capacity at higher temperature will decrease, because the hottest point has to be kept under 110°C.[1]

C_A: Additional capacity can be added by adding more power transformers on the lines.

$$C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + C_A = (1 - x)\, C_E + C_A$$

- **Capacity (overhead conductors)**

[1] For example: temperature of 40°C during 10 hours, the average load should not excess 80-85% of the nominal kVA.

C_E: 100% at 75°C for ACSR conductors and 25°C ambient (manufacturers' limits).
Effects of high temperature can results in the annealing[2] of aluminum used within ACSR and AAC conductors. This effect begins at 93°C for these types of conductors, and is a function of the magnitude of the temperature and the duration of the application (electrical power flow).

$C_{\Delta E}$: x%, where x is lower than 100. The added combination of high temperature and higher current flow will significantly reduce the capacity of the conductors.
Other impacts: loss of strength due to annealing, increase in sag.

C_A: Capacity can be added by using other or larger types of conductors. However, in some place it could be difficult to do so as it would means to redesign the existing lines and may result, for example, in the replacement of existing poles by stronger ones generating high costs.

$$C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + C_A = (1 - x)\, C_E + C_A.$$

The reduction of the capacity is difficult to calculate because of the great diversity of operating circumstances and loading of the entire system. However, calculations for critical areas, where added capacity can be difficult to do, should be done.

- **Vulnerability Ratio:** Cannot be calculated because too many variables are not known.

- **Conclusion: Further action recommended.** Higher temperatures will have impacts on the overall capacity of the power lines. In the downtown area, there are critical, constrained areas (i.e. built up zone) where added conductor/transformer capacity may be difficult to implement.

11. High nighttime temperatures / Overhead power lines (radial)

- **Results and consequences:** risk rating 14
  Overload of the ONAN power transformers

- **Load and Capacity:**
  Refer to the previous evaluation. However, the capacity of the power transformers will not be reduced as much as for higher daily maximum temperature. Therefore, $C_E = xC_E$, with x as a small value.

  High nighttime temperatures have consequences on the capacity of the power transformer to cool enough before being loaded the next day. Climate projections show a significant increase in the number of days with low night time temperatures ≥ 23°C. The actual design of power transformers can support this temperature limit. As such, this impact was judged as low.

- **Conclusion: No further action required.** Night time temperatures with minimum ≥ 23°C will not have big impacts on the delivery of electricity. However, it is important to note that combination events of high daily temperature and high night time temperature are a concern. This is taken into account under the parameter, average temperature over 30°C on a 24 h basis.

12. Freezing Rain - Ice Storm 15 mm and high winds 70 km/h / Overhead Feeders in Loop Configuration

- **Results and consequences**: risk ratings of 28, 35 Conductors (tree contacts).

- **Load:**

[2] Annealing is the metallurgical process where applied temperature softens hardened metal resulting in loss of strength. For overhead conductors, annealing can degrade the strength of aluminum wires used in ACSR and AAC conductors (PJM Overhead conductor Ad Hoc Committee, 2010)

L_E = the actual load is based on tree branches that usually start to break with a 15 mm of freezing rain.

L_C = freezing rain of 15 mm will happen a little bit more often for the study period (from 0.11/year to 0.12/year to 0.16/year). Hypothesis $L_C = L_E$

L_o = N/A

$L_T = L_E + L_C + L_O = L_E$.

- **Capacity :**

C_E: Actual overall ''capacity'' of the tree canopy in Toronto.

$C_{\Delta E}$: $C_{\Delta E} = C_{future} < C_E$. The future overall ''capacity'' will decrease (or vulnerability to damage will increase) because of new or exacerbated disease and pest conditions and possibly, because of the tree faster growth (extended growing season, more branches).

C_A: N/A

$C_T = C_E - C_{\Delta E}$

- **Vulnerability Ratio**
  - $VR = \frac{Lt}{Ct} = \frac{Le}{Ce - C\Delta\text{E}}, where\ \frac{Le}{Ce} = 1, as\ Ce - C\Delta\text{E is smaller,}$ V_R will be >1

- **Capacity deficit**

$C_D = L_T - C_T$ = It cannot be calculated because the future capacity of the trees is not known.

- **Conclusion: Further action recommended.** The risk assessment completed in step 3 for radial systems resulted in a high risk rating for this interaction. In overhead loop systems, it was hypothesized that their more redundant configuration would reduce customer interruptions, affect fewer clients or cause outages of shorter durations, thus yielding a high-medium risk rating of 35. However, freezing rain events are expected to occur slightly more often than it does currently by the end of the study horizon. The tree canopy may also be affected by new or increased disease threats and extended growing season. Conductors will also sag more due to more extreme weather (ice, warm weather, etc.) leading to more contacts with the tree branches. According to THESL (Toronto Hydro - OM&A 2014): "*Vegetation interference is one of the most common causes of power interruption*". Finally, freezing rain events tend to be widespread, and there is no reason to believe that both branches of an overhead loop circuit might not be equally susceptible to damage. For all of these reasons, all overhead power lines, irrespective of electrical configuration, were deemed as vulnerable.

13. Freezing Rain/Ice Storm 60 mm ≈ 30 mm radial (major outages) / Overhead lines (radial and loop)

- **Results and consequences**: risk rating 24, 28
  Overhead lines could fall down, salt contamination

- **Load**

L_E = Actual load is equal to the actual number of days of freezing rain

L_C = The load due to the freezing rain will slightly increase, $L_C = aL_E$, where ''a'' is a % of increase (small)

L_o = N/A

$L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E \rightarrow L_T > L_E$

- **Capacity**

C_E: The overhead power lines in the Toronto area are designed based on the CSA standard 22.3. Loads and load combinations correspond to so-called “Heavy Loading” specified in Table 30 of the CSA standard: wind of 400 Pa, 12.5 mm ice, -20°C temperatures.

$C_{\Delta E}$: It is assumed that the capacity will remain the same if the design criteria are not changing. **$C_{\Delta E} = 0$**

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A = C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{Ce} > 1\text{, the infrastructure is vulnerable}$$

- **Capacity deficit**

$C_D = L_T - C_T = (1 + a)\, L_E - C_E.$

- **Conclusion: Further action recommended.** See explanation for freezing rain and stations (item 5 above).

14. Lightning / Overhead power lines (radial and open loop) and SCADA system

- **Results and consequences**: risk rating of 18, 24, 30, failure of equipment (localized).

- **Vulnerability Ratio:** In this case, the impact comes from a direct or indirect strikes and has no consequences on the load and capacity of the infrastructure.

- **Conclusion: Further action recommended.** It is difficult to predict the increase of lightning strikes for the study period; however it is interesting to note that the probability of a lightning strike in an area of 0,015 km^2 anywhere within the City of Toronto is very high for the study period. At the moment, the number of arrestors/km, lightning strike intensity and arrestor performance are not monitored by Toronto Hydro. In the absence of this information, and since lightning strikes are currently a frequent source of outages, lightning strikes were judged to be a continued vulnerability. Further studies could evaluate if the actual protection of overhead power lines is sufficient, or if investments for more protection needs to be made. Direct strike impacts can be studied with software (e.g EMTP), while indirect strikes can be calculated numerically.

15. Snow > 5 cm and Snow > 10 cm / Overhead power lines (radial)

- **Results and consequences**: risk ratings of 14, salt deposited on the roads can also accumulate on insulators from water evaporation and transport through the air, and can create a failure (reduce the effective insulation levels and can lead to insulator tracking, flashover and potential pole fires or switch with porcelain insulator failure).

- **Vulnerability Ratio:** In that case, the impact is indirect and has no consequences on the load and capacity of the infrastructure.

- **Conclusion: No further action required.** The number of snow days is highly variable. The trend seems to be decreasing, but snow days will still occur annually. During the workshop, Toronto Hydro mentioned having problems regarding insulator tracking leading to pole fires especially at higher voltages (13.8 kV and 27.6 kV) and switch failures. However, Toronto Hydro is already monitoring and dealing with this issue. From THESL’s report (Toronto Hydro - OM&A 2014): *to mitigate the risk of contamination and insulator tracking, insulators at the highest risk locations are washed twice a year.* Furthermore, recall that porcelain insulators are being progressively replaced by polymer insulators. *Polymer insulators are hydrophobic, and are not susceptible to the same failure mode due to contamination. […] Regular maintenance enables the detection and prediction of common failure modes. One such mode is the failure of switch's porcelain insulators. […] Porcelain switches pose high safety risks due to their susceptibility to contamination build-up and electrical tracking, which can lead to cracking […] posing a safety risk to employees or members of the public below.* As older porcelain insulators are being replaced by polymer insulators, it was judged that no further action than what is currently underway is required.

1.2.2 Civil structures

16. Extreme Rainfall, Freezing rain/Ice storm 15 mm & 25 mm & 60 mm (Combination of events) / Civil structures: Underground feeders (Former Toronto)

- **Results and consequences**: risk rating of 12, 14
  Accelerated corrosion of reinforcing bars and degradation of concrete in cable chambers and vaults.

- **Load**

L_E = Currently, civil structures (cable chambers, vaults) degrade at a pace related to the actual load (salt and moisture) related to current weather: Extreme Rainfall (100 mm) 0.04/year + Ice Storm (15 mm) 0.11/year + Ice Storm (25 mm) 0.06/year + Ice Storm (6hrs+) 0.65/year.

L_C = In the future, the structures will degrade more rapidly due to the more severe weather:
2030: Extreme Rainfall (100 mm) unknown but increase + Ice Storm (15 mm) 0.12/year + Ice Storm (25 mm) 0.07/year + Ice Storm (6hrs+) 0.73/year.
2050: Extreme Rainfall (100 mm) unknown but increase + Ice Storm (15 mm) 0.16/year + Ice Storm (25 mm) 0.09/year + Ice Storm (6hrs+) 0.94/year.

L_o: No other load.

$L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E$

- **Capacity**

C_E: actual capacity based on design criteria

$C_{\Delta E}$: As vaults are getting older, the capacity of the structures will decrease (approximately 60% of all network vaults will reach their expected life within the next ten years and 80% of network vault roofs and 60% of all cable chamber roofs are already beyond their useful life (Toronto Hydro - OM&A, 2014).

For the purpose of the study, we can then assume that $C_{\Delta E} = aC_E$, where ''a'' equal a percentage of diminution of capacity versus actual capacity

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A$ $= (1-a)C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{(1-a)Ce} > 1$$, the infrastructure component is vulnerable

- **Conclusion: Further action recommended.** Vaults and chambers already suffering from degradation issues will deteriorate more rapidly over time. From THESL (Toronto Hydro - OM&A 2014): *As below-grade structures age, the greatest concern becomes structural strength. Structural deficiencies affecting vaults include degradation of concrete and corrosion of supports such as beams and rebar. Once degradation and* *corrosion sets in, conditions can deteriorate rapidly and in many cases from one season to the next. Of particular concern is the winter season when moisture and water enter in below*-grade *structures, freezes and thaws, and carries with it salt that has been used at grade to melt ice and snow.*

While maintenance can reduce the rate of deterioration, incidence of extreme rainfall, snowfall, freezing rain and the application of road salt will persist throughout the study period and continue to contribute to the premature aging of civil structures. While, it could not be determined in the study whether premature aging of civil structures will be exacerbated by a changing climate, this issue will persist over the study period and is therefore judged as an on-going vulnerability.

17. Snow > 5 cm and Snow > 10 cm / Civil structures: Underground feeders (Former Toronto)

- **Results and consequences**: risk ratings of 14, 21, Degradation of concrete in cable chambers and vaults.

- **Load**

L_E = Actually the civil structures (cable chambers, vaults) degrade at a rhythm caused by current climate.

L_C = The ''load'' will probably decrease. $-aL_E$

L_o = No other load.

$L_T = L_E + L_C + L_O = L_E - aL_E = (1\text{-}a)L_E$

- **Capacity**

C_E: actual capacity based on design criteria

$C_{\Delta E}$: As vaults age, the capacity of the structures will decrease (approximately 60% of all network vaults will reach their expected life within the next ten years and 80% of network vault roofs and 60% of all cable chamber roofs are already beyond their useful life, (Toronto Hydro - OM&A, 2014)).

For the purpose of the study, we can then assume that $C_{\Delta E} = bC_E$, where ''a'' equal a percentage of diminution of capacity versus actual capacity

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A$ $= (1\text{-}b)C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1-a)Le}{(1-b)Ce}$$, it is not possible to know if a will be < or > b

- **Conclusion: No further action required, but combinations of climates events require additional study.** As days with snow will probably decrease, the snow days alone were not judge to be a significant vulnerability. However, snow days will still occur over the study period, and in combination with extreme rainfall, freezes and thaw, freezing rain, and the continued application of road salt, premature degradation of civil structures was judged to be an ongoing vulnerability for Toronto Hydro.

18. Frost / Civil structures (overhead and underground feeders)

- **Results and consequences**: risk rating of 14, frost heave of civil structures

- **Vulnerability Ratio:** In the future, the ''load'' will reduced as less frost days are expected. However, as vaults and as the foundations for concrete or steel poles age, the capacity of the structures will decrease.

  Conclusion: Further action recommended. Even if the frost threat is decreasing, it is noted that frost penetration will still occur during the study period with occasionally extreme weather. Since, Toronto Hydro already experiences problems with frost and its civil infrastructure, frost impacts were judged to be a vulnerability.

19. All Climate Parameters / Human Resources

- **Results and consequences:** risk ratings of 14 to 28, weather related impacts on safe site access, work conditions and travel

- **Conclusion: Further action recommended.** While occupational health and safety procedures will continue to be in place in the future, human resources will continue to be vulnerable to climate change related weather events due to the need to travel, access, and work on equipment in spite of the weather.

Appendix H
PIEVC Worksheets

Worksheet 1 and 2 have been removed from the public version of this report.

However, information on infrastructure can be found in summary form in Chapter 2 of this report. Climate information can be found in Chapter 3, and in Appendix B and Appendix C of this report.

Worksheet 3 information can be found in Appendix D.

Worksheet 4 information can be found in Appendix G.

Worksheet 5 information is contained within Chapter 7 of this report.

D3 Asset Lifecycle Optimization

Exhibit 2B, Section D1 provided an end-to-end overview of Toronto Hydro's distribution system Asset Management System ("AMS"), from strategic planning, to execution and reporting, including the translation of corporate and stakeholder requirements into asset performance and asset management capability objectives. Section D2 provided an overview of the current state of the major distribution assets that the utility manages based on asset demographics, system configurations and various observable features of Toronto Hydro's distribution service area. Section D3 focuses on key factors that guide and influence investment pacing and prioritization decisions within the AM Process.

- **Section D3.1** provides an overview of the replacement, refurbishment, and maintenance approaches that Toronto Hydro applies to major asset classes to optimize the value derived from individual assets over their lifecycles. These asset lifecycle optimization practices are the fundamental building blocks for asset management and investment planning at Toronto Hydro;
- **Section D3.2** describes the ways in which the utility considers and manages failure risk in its AMS. Risk management takes various qualitative and quantitative forms and is fundamental to deriving expenditure plans that support the optimization of future outcomes within a constrained budget;
- **Section D3.3** describes the ways in which the utility considers and manages capacity risk in its AMS; and
- **Section D3.4** describes the expenditure program planning process that Toronto Hydro uses to derive a capital expenditure plan from its AMS.

For an overview of how the practices discussed in this section informed Toronto Hydro's 2025-2029 Capital Expenditure Plan for system-related investments, see Exhibit 2B, Section E2.2.

D3.1 Asset Lifecycle Optimization Practices

As noted in Exhibit 2B, Section D1, the broad objective of Toronto Hydro's AMS is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders. At the most fundamental level, this value is realized by consistently implementing prudent lifecycle optimization practices tailored to specific asset classes. These practices serve as guidelines for when and how to inspect and intervene on a specific asset, where intervention includes asset maintenance, refurbishment, and replacement.

Toronto Hydro's lifecycle optimization practices are the result of decades of experience managing major distribution assets across a dense, mature, and congested major city that is served by various system designs and configurations. These practices consider the various attributes of an asset class, including, but not limited to: (i) the intended functionality of the asset in the distribution system and the various modes of deterioration and failure over the asset's typical lifespan; (ii) the potential impact of various failure modes on distribution service; and (iii) the typical costs and customer impacts of intervention.

As discussed in Section D1, Toronto Hydro is committed to continuous improvement in asset management, and is pursuing certification under the internationally recognized ISO 55001 standard for Asset Management in the 2025-2029 period. The utility expects that the journey toward certification will involve additional improvements and refinements to its asset lifecycle optimization practices, including more comprehensive documentation and governance of said practices and associated processes and decision-making tools.

The following two sub-sections describe Toronto Hydro's asset lifecycle optimization practices, beginning with the utility's foundational maintenance and refurbishment practices, followed by a description of the utility's typical asset replacement practices for major asset classes.

D3.1.1 Maintenance and Refurbishment Practices

As part of its overall asset management process, Toronto Hydro aims to ensure the continuous serviceability (i.e. usefulness) of assets over their typical or expected useful lives, and to extend an asset's serviceability when it is feasible and economical to do so. Asset maintenance and refurbishment practices are the methods by which Toronto Hydro supports these objectives.

D3.1.1.1 Reliability Centered Maintenance

Toronto Hydro typically conducts inspection and maintenance tasks on a fixed cycle, however some tasks are performed on a variable cycle. These activities are focused on preserving and maximizing an asset's performance over its expected useful life while mitigating a wide variety of system risks. Maintenance activities support the minimization of overall lifecycle costs and account for factors such as the safety of Toronto Hydro employees and the public, responsible environmental stewardship and associated obligations, and compliance with statutory and regulatory requirements.

Toronto Hydro's foundation for maintenance planning is Reliability Centered Maintenance ("RCM"), an established engineering framework for the maintenance of assets throughout their lifecycles. The RCM framework determines failure management policies for any physical asset in its present operating context to maximize useful life and reliability based on the assets function, and the consequences of functional failure, including the asset's criticality to the distribution system. The output of an RCM analysis includes a failure mode analysis, which is used to identify proactive tasks (with associated time intervals) that help to predict or prevent failures from occurring. It also focuses on preventing failures where consequences are most severe. Toronto Hydro initially adopted an RCM framework in 2003 and subsequently reviewed and updated its outputs in 2011 and over the 2016 and 2017 period, ensuring compliance with the Society of Automotive Engineers ("SAE") standards SAE JA-1011 and SAE JA-1012 which sets outs the minimum characteristics that a process must have in order to be an RCM process and provides guidance on how to meet the requirements of SAE JA-1011, respectively.[1] The resulting analysis produces failure management policies forming part of the maintenance program that are deemed to be the most cost and risk effective at sustaining asset performance in accordance with the company's risk tolerance level.

RCM is a comprehensive approach to the lifecycle maintenance of distribution system assets. Initially developed in the airline industry to manage high maintenance costs and high failure rates, RCM has allowed Toronto Hydro to increase its analytical capabilities in determining the optimal level of maintenance expenditures and the appropriate time of intervention for a specific asset class. The RCM framework incorporates a thorough analysis of assets going beyond manufacturers' requirements to evaluate functional failures under utility-specific operating conditions. The analysis identifies and categorizes consequences of failure (i.e. safety, cost, reliability). Maintenance programs are subsequently set to mitigate these consequences by establishing recommended optimal asset intervention timelines.

The benefits of RCM include:

1) A structured and data-driven targeted maintenance program;
2) Reduced efforts and costs expended on maintenance programs with little resultant value; and
3) Increased reliability due to the effectiveness of the failure prevention program.

[1] Society of Automotive Engineers, SAE JA-1011 (August 2009) and SAE JA-1012 (August 2011).

Toronto Hydro leverages the RCM framework, in combination with the Ontario Energy Board's ("OEB")'s Minimum Inspection Requirements, and the continuous monitoring and assessment of asset performance, to derive its maintenance programs and associated expenditure plans.

As part of developing RCM-based maintenance program expenditure plans, Toronto Hydro continues to seek opportunities for incremental productivity. For example, the utility has standardized the maintenance cycles of overhead switches to align with station maintenance cycles whenever possible to minimize the need for multiple equipment outages and significant switching resources.

The expenditure plans for all planned maintenance programs can be found in Exhibit 4, Tab 2, Schedules 1-3. Table 1 below provides a summary of maintenance practices for the major asset types on each part of Toronto Hydro's distribution system.

Table 1: System Maintenance Practices

System	Asset Class/Type	Planned Maintenance Activities	Current Cycle	Proposed 25-29 Changes
Overhead	*Pole-top Transformer*	Line Patrols	3 Years Visual, 1 Year Infrared	
	Distribution Poles	Line Patrols	3 Years Visual	
		Wood Pole Inspection & Treatment	10 Years	8 Years
		Concrete & Steel Poles	-	10 Years
	Primary Conductors	Line Patrols	3 Years Visual, 1 Year Infrared	
		Tree Trimming	2-5 Years, with the majority being 3 Years	
	Secondary Conductors	Line Patrols	3 Years Visual	
	Switches	Line Patrols	3 Years Visual, 1 Year Infrared	
		Maintenance (SCADA-Mate & Gang-Operated)	Variable Cycle Greater than 6 Years	6 Years

System	Asset Class/Type	Planned Maintenance Activities	Current Cycle	Proposed 25-29 Changes
		Battery Replacement for Switches (SCADA-Mate & Gang-Operated) and Repeater Radio	3 Years	
	Insulators	Insulator Washing (for Porcelain)	6 Months	
Underground	*Padmounted Transformer*	Inspection (Civil + Electrical)	3 Years	
	Submersible Transformer	Vault Inspection (Civil + Electrical)	3 Years	
	CRD Transformer		1 Year	
	URD Transformer			
	Building Vault Transformer	Inspection (Civil + Electrical)	3 Years	
	Padmounted Switch	Inspection (Civil + Electrical)	1 Year	
		Battery Replacement	3 Years	
	Cable Chamber	Cable Chamber	10 Years	
	Cables	Cable Diagnostic Testing	Risk Based	
		Contact Voltage Scanning	1-3 Years	
Network	*Network Transformer*	Network Vault Inspection – Electrical	1 Year	
		Network Vault Inspection – Civil	6 Months	1 Year
		Reverse Power Breaker Overhaul	3 Years	
		Protector Top Cleaning	1 Year	
		Network Protector Overhaul - HV[2]	4 Years	

[2] High Voltage ("HV")

System	Asset Class/Type	Planned Maintenance Activities	Current Cycle	Proposed 25-29 Changes
		Network Protector Overhaul - LV[3]	5 Years	
Station	*Station TS & MS (Maintenance & Facilities)*	Monthly Inspections	1 Month	
		Seasonal Detailed Inspection	6 Months	
	Circuit Breaker (All Types) & Switch	Maintenance	4 Years	
	Bus Disconnect Switches			
	B-Bus	B-Bus Cleaning	4 Years	
	Power Transformer	Equipment Maintenance	4 Years	
	DC Battery & Charger	Seasonal Detailed Inspection	6 Months	
	Compressed Air System	Station Compressed Air System Maintenance	6 Months	
	Station Alarms in Downtown	Alarm Testing	1 Year	
	Pilot Wire	Pilot Wire Protection	6 Years	

The proposed changes in cycles for certain asset types are explained below:

- Starting in 2025, Toronto Hydro will be adjusting the inspection cycle for wood poles from ten to eight years in order to better manage the growing volume of wood poles past their useful life, and in HI4 and HI5 condition based on the ACA. This adjustment will also allow Toronto Hydro to better inform its wood pole ACA and support planning of system renewal investments with more timely inspection data of poles in poor condition.
- In 2025, Toronto Hydro will begin to inspect concrete and steel poles as part of its dedicated pole inspection program on a ten-year cycle. Inspections of these poles are supported by the

[3] Low Voltage ("LV")

CSA Standard C22.3, are expected to reduce burden on reactive capital, and will allow Toronto Hydro to improve decisions on planned renewal investments for these assets.

- Due to resourcing and operational constraints, Toronto Hydro has historically found achieving the four-year maintenance cycle of overhead switches noted in its 2020-2024 DSP to be challenging, instead attaining variable cycles generally greater than six years. Beginning in 2025, Toronto Hydro will be maintaining overhead switches on a six-year inspection cycle at a minimum, an approach that is supported by an independent study of Toronto Hydro's overhead switch maintenance practices.
- As of 2027, Toronto Hydro's network vaults will have sensors providing remote monitoring and control, which will allow the utility to reduce the number of on- site inspections, yielding cost savings from the adjustments of maintenance cycles from six months to one year.

D3.1.1.2 Summary of Maintenance Programs and Activities

Asset maintenance programs (Exhibit 4, Tab 2, Schedules 1-5) are grouped into four major categories based on their functionality, as shown below:

- Preventative Maintenance;
- Predictive Maintenance;
- Emergency Maintenance; and
- Corrective Maintenance.

The framework of preventative and predictive maintenance programs is driven primarily by regulatory requirements, as mandated by the OEB's Distribution System Code Minimum Inspection Requirements.[4]

Capturing Asset Deficiencies

The details of how the asset inspections and capital and maintenance programs are related are summarized below as part of the deficiency capturing process in Figure 1.

[4] Ontario Energy Board, Distribution System Code, (August 2, 2023), Appendix C.

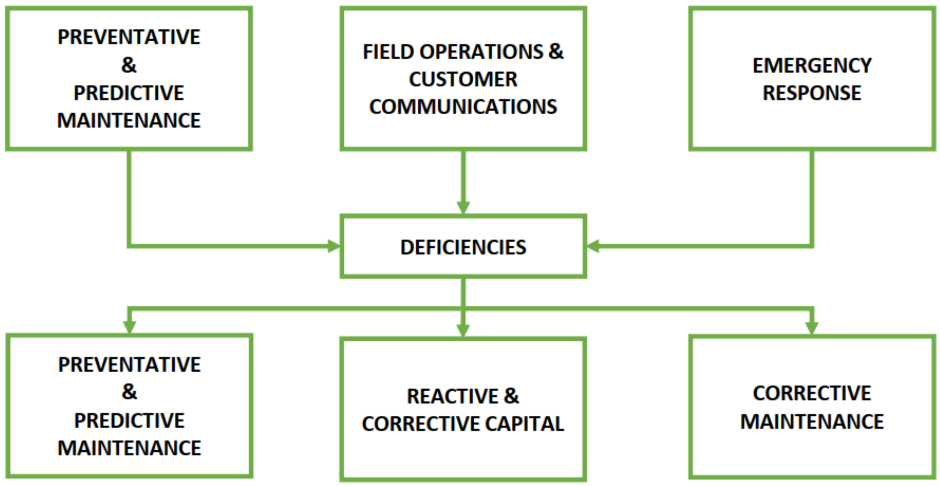


Figure 1: Deficiency Capturing Process

Distribution system events such as power outages are initially addressed through the Emergency Response program.[5] The cost of any capital work (e.g. major asset replacement) carried-out during an Emergency Response event is captured in the Reactive Capital program.[6] An Emergency Response event can also result in follow-up work to be carried out via the Reactive Capital segment.

The more substantial source of Reactive and Corrective Capital work is the identification of asset failures and deficiencies through maintenance activities and daily utility operations.

- Toronto Hydro's Preventative and Predictive Maintenance programs systematically identify asset failures and prioritize deficiencies through regularly scheduled system maintenance activities. Through the "find it and fix it" practice, on-site repair of minor deficiencies is carried out.[7]

- Failures and deficiencies are also identified through daily field operations and customer contact. These include observations by field crews and system operators during the normal course of operations, external emails, customer inquiries requiring field assessment and follow up including phone calls received from the customer service team, and meter errors captured through internal data collection systems.

[5] Exhibit 4, Tab 2, Schedule 5.
[6] Exhibit 2B, Section E6.7.
[7] Exhibit 4, Tab 2, Schedules 1-3.

These processes and activities can result in both capital and operating expenditures (e.g. corrective tree trimming). The Corrective Maintenance program,[8] is the operational counterpart to the Reactive Capital segment.[9]

Toronto Hydro has a rigorous process for reviewing all work inquiries from these sources to validate the need for reactive intervention, assess the nature of reactive intervention required (i.e. capital versus maintenance), and the level of urgency/priority to be assigned to each item. Prioritization of the asset deficiencies identified as part of the work request process is based on the urgency of the work and how quickly it needs to be resolved. The work requests are classified into three categories (P1, P2, and P3) as discussed in Section D3.2.1.3 and illustrated in Figure 2. Toronto Hydro also identifies a P4 category of deficiencies, which require monitoring, but for which no work requests are issued.

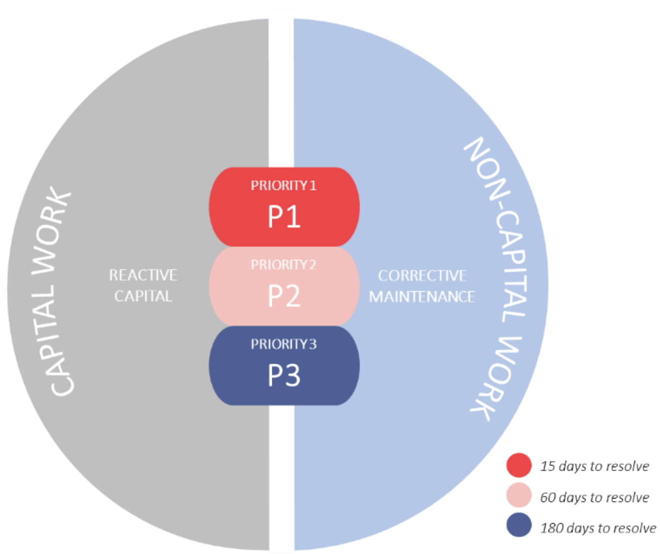


Figure 2: Work Request Prioritization

1. Preventative Maintenance

This type of maintenance involves inspections and maintenance tasks on a fixed or variable cycle, which emphasizes preserving asset performance over its expected life, and maintaining public and employee safety. Maintenance cycles are typically defined based on the average time between

[8] Exhibit 4, Tab 2, Schedule 4.
[9] *Supra* note 6.

failures of a given asset class, and are intended to maintain the asset before it is statistically likely to fail. An example of a preventative maintenance task is the inspection of wooden utility poles, which Toronto Hydro currently carries out on a ten-year cycle and intends to shift to an eight-year cycle in the next rate period.[10]

2. Predictive Maintenance

Predictive maintenance involves the testing and inspection of equipment for predetermined conditions that are indicative of a potential failure. The results of this process feed into asset investment decision-making frameworks such as Toronto Hydro's Asset Condition Assessment, and will trigger corrective tasks to prevent failures when necessary. Predictive maintenance is the most effective maintenance approach for assets that exhibit conditions that can be identified, practically monitored, and corrected prior to failure. An example of a predictive maintenance task is the Dissolved Gas Analysis of power transformer mineral oil, which identifies the presence of dissolved gases and other chemical compounds in the oil as an indication of potential failure modes (e.g. overheating, excessive moisture, or breakdown of the insulating paper). Corrective maintenance tasks can then be undertaken to correct the deficiencies to avoid equipment failure. For additional information.[11]

3. Emergency Maintenance

Emergency maintenance involves the urgent repair or replacement of equipment that has failed or is in imminent danger of failure, in order to restore or maintain power in Toronto Hydro's distribution system. This type of maintenance may also involve an immediate response to a safety or environmental hazard. Emergency Maintenance can arise from: response to requests for support from Toronto Emergency Management Services and the public, equipment failure, events related to severe weather, motor vehicle accidents, power quality issues, and reactive equipment isolations. It emphasizes safe and prompt response to restore service or prevent a service disruption. An example of emergency maintenance would be restoration of service to customers that have lost power due to a broken tree branch on the overhead lines.[12]

[10] *Supra* note 7.
[11] *Ibid.*
[12] Exhibit 4, Tab 2, Schedule 5.

4. Corrective Maintenance

Corrective Maintenance involves repairing equipment after a deficiency has been reported via preventative and predictive maintenance tasks or other sources, such as inquiries from customers, feeder patrols, and deficiencies identified by crews during day-to-day operations. Corrective work activities contribute to maintaining safety, environmental integrity, and overall system reliability. These tasks typically involve a short planning horizon since a portion of the distribution system is faulted, isolated, or in otherwise in an unacceptable condition.

Corrective Maintenance contributes to public and employee safety by ensuring prompt repair or replacement of high-risk assets or asset components approaching imminent failure; eliminating safety risks such as trip hazards caused by sink holes on sidewalks and the absence of adequate pole guying, washing insulators located in high contamination areas to prevent flashover, and detection and elimination of energized contact voltage on surfaces and structures within Toronto Hydro's distribution system. Corrective work also contributes to Toronto Hydro's environmental objectives, for example by repairing cables and splices exhibiting signs of oil deficiency to prevent oil spills into the environment, and prevention of excessive corrosion by cleaning oil-filled equipment and applying corrosion inhibiting coatings. Other examples of Corrective Maintenance tasks include: (i) the replacement of a cracked porcelain insulator; (ii) the repair of a broken guy wires; (iii) the removal of vegetation growing on a pole and into an overhead line; or (iv) the replacement of a conductor splice.

Corrective maintenance can also be required as a result of an unplanned system events or emergencies. For example, a faulted section of underground cable that had been isolated from the system during an emergency response can be unearthed and repaired or replaced as a Corrective Maintenance action. For additional information, please refer to the Corrective Maintenance program.[13]

D3.1.1.3 Impact of Capital Investments on Maintenance

Toronto Hydro routinely assesses the impact of its capital investments on distribution system maintenance needs and planning. A significant portion of maintenance program expenditures is directed toward activities that are independent of capital investments, including: (i) routine maintenance to preserve asset performance over its expected life; (ii) vegetation management to

[13] *Supra* note 8.

maintain minimum clearance requirements for overhead conductors and equipment; (iii) and cyclical patrols and inspections undertaken to comply with minimum requirements under the Distribution System Code; and (v) emergency maintenance following severe weather and storm damage. Maintenance programs also provide the asset condition information necessary to plan sustainment programs. Where there is an impact, the directional relationship between capital investments and maintenance depends on a number of factors, including the type of investment (e.g. Growth and City Electrification, Sustainment and Stewardship, or Modernization), mandated requirements (e.g. OEB minimum inspection cycles), and the specific characteristics of the assets involved.

Growth investments are generally expected to put upward pressure on maintenance requirements as the number of assets on the distribution system increase to accommodate new customers. For example, the addition of Copeland TS (Phase 1) has increased the number of TSs (and station assets) that the utility has to regularly inspect and maintain, with some of these inspections occurring on a monthly basis. The expansion of Copeland TS (Phase 2) will similarly increase the number of station assets requiring maintenance, once complete. While these types of large, discrete S=stations expansion projects are fairly infrequent, more routine growth investments also tend to increase the total number of assets that must be incorporated into Toronto Hydro's existing preventative and predictive maintenance cycles. For example, from 2017 to 2022 the number of distribution transformers on Toronto Hydro's system increased by over 750 and the number of poles increased by over 4,500. 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,[14] and expects to expand this to additional Toronto Hydro-owned energy storage systems as they are added under the Non-Wires Solutions capital program.[15]

Within the Sustainment and Stewardship investment category, typical like-for-like asset replacement is generally expected to have no impact on routine maintenance and inspection requirements, especially where, as is most common, these investments are aimed at maintaining rather than improving overall asset condition. In certain cases, where Toronto Hydro conducts condition-based maintenance (increased frequency of maintenance activities for higher-risk assets within a population based on condition assessments), the utility could potentially reduce the number of

[14] Exhibit 4, Tab 2, Schedule 3.
[15] Exhibit 2B, Section E7.2.

assets requiring the higher maintenance frequency through capital investments aimed at improving condition demographics. As an example of condition-based maintenance, Toronto Hydro increased the frequency of inspections for Submersible Transformer during the period of 2019-2020 to manage the incremental risk posed by oil deficiencies within the submersible transformer population at that time prior to returning to a three-year cycle once the risk has been adequately managed. Typically, the impact would be minimal and this approach is not consistent with Toronto Hydro's general sustainment strategy to maintain asset condition. Similarly, like-for-like replacement activities will only reduce aggregate Corrective Maintenance expenditures if replacements are done at a high enough pace to materially improve asset health demographics, which could in turn reduce the expected volume of deficiencies requiring corrective intervention (e.g. repair). However, even this dynamic can be 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). In reality, Toronto Hydro has seen a rise in the volume of corrective work requests. This has resulted in approximately $20 million worth of backlog for lower priority work requests, which the utility expects will continue to grow.

Where Sustainment and Stewardship investments are removing legacy and functionally obsolete assets or configurations from the system, this can eliminate the need for maintenance activities or higher maintenance frequencies that are specific to the legacy asset type. Toronto Hydro anticipates that Sustainment and Stewardship programs targeting legacy assets such as air-blast circuit breakers, non-submersible network protectors, porcelain insulators, box construction, and rear lot construction will contribute to a gradual and modest reduction in costs related to legacy equipment maintenance as the population declines and the assets are replaced with equipment that typically requires lower maintenance costs, or are maintenance free. For example, unlike newer types of circuit breakers, air-blast circuit breakers require air compressors to function, and Toronto Hydro inspects and maintains these air compressors twice a year. As Toronto Hydro removes air-blast circuit breakers from the system through its Stations Renewal program,[16] it will aim to reduce and eventually eliminate the volume of these inspections under the Preventative and Predictive Station Maintenance program.[17] Sustainment and Stewardship programs, including Area Conversions, Underground System Renewal – Horseshoe, and Overhead System Renewal, also contribute to the gradual removal of the legacy 4.16 kV system, which enables the decommissioning of Municipal

[16] Exhibit 2B, Section E6.6.
[17] Exhibit 4, Tab 2, Schedule 3.

Stations, reducing the overall volume of station maintenance and inspection activities. At the same time, new equipment, and new standards and practices may introduce incremental maintenance requirements. The utility considers maintenance requirements when evaluating new products and developing new standards as part of its continuous Standards and Practices Review activities.

Replacement of legacy systems can also help to reduce emergency and corrective maintenance. Legacy designs in poor condition may require more frequent corrective or emergency repair as more components are expected to fail, and there is an increased risk to reliability, safety, and environment outcomes. In addition, obsolete assets and configurations can have access, capacity, and procurement issues that may increase costs during corrective or emergency work. For example, both the Rear Lot and Box Construction configurations addressed by the Area Conversions program are targeted, in part, because of the challenges crews face in accessing them for repairs and the corresponding tendency towards longer outages.[18] Rear Lot feeder outages are on average 2.5 hours longer than outages on the rest of the system and these feeders can be particularly vulnerable to outages during adverse weather contributing to higher emergency maintenance costs. In May of 2022 there was a derecho wind storm which interrupted power to approximately 142,000 Toronto Hydro customers including customers on three Rear Lot feeders, which were out for more than two days, with the longest lasting 53.1 hours.

Modernization investments often have the greatest potential to reduce maintenance costs, although like growth investments, they tend to include the installation of new assets, such as SCADA-mate switches and reclosers under the System Enhancements program,[19] which contribute to increasing volumes of routine maintenance and inspection activities. The Network Condition Monitoring and Control ("NCMC") program is one modernization investment that has a clear benefit in terms of reducing expected maintenance costs.[20] As a result of the implementation of NCMC, which installs sensors in network vaults providing remote monitoring and control, 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.[21]

[18] Exhibit 2B, Section E6.1.
[19] Exhibit 2B, Section E7.1.
[20] Exhibit 2B, Section E7.3.
[21] Exhibit 4, Tab 2, Schedule 2.

D3.1.1.4 Overview of Toronto Hydro's Refurbishment Practices

Both maintenance and refurbishment involve intervening on an asset to maintain or maximize its serviceability. Maintenance consists of activities that are necessary to ensure the reliable operation of an asset over its expected useful life. Refurbishment differs from maintenance in that it involves renovating an asset to extend its serviceable life. For example, tree trimming is a form of maintenance, while rebuilding a vault roof is a form of refurbishment.

Toronto Hydro's refurbishment efforts are mainly focused on assets that have been taken out of service (e.g. through a renewal project or as a result of failure). An asset may be considered for refurbishment if it meets specific criteria and is in good enough condition to be reintroduced into the system after appropriate testing. This is done for major asset types like transformers, network protectors, switchgears, and switches. Toronto Hydro evaluates major equipment returned from the field, and categorizes it based on the following criteria:

1) **Decommissioned equipment that remains operational:** Should a major asset such as a station power transformer be removed from the system as part of a system renewal project, or due to station decommissioning, Toronto Hydro will inspect and test the equipment to determine if it is still fit for service. If the equipment is still operational, the utility will keep it as a spare in case of reactive replacements.
2) **Repair of failed or defective equipment:** Equipment will be repaired or refurbished if it meets the following criteria: (i) it is under warranty; (ii) it is a critical spare (e.g. 4 kV assets); (iii) transformers less than 15 years old; (iv) network protectors less than 10 years old; (v) overhead switches less than five years old; or (vi) underground switches less than 15 years old. An example would be load conversion, where 4 kV equipment is removed from the system and replaced with the current standard. The removed assets are typically refurbished and kept as spares due to the scarcity of these obsolete asset types and in the event that other 4 kV assets on the system need to be replaced reactively.

Equipment that does not meet the specific criteria for re-use listed above will be scrapped.

Where appropriate, Toronto Hydro undertakes targeted refurbishments in the field to maximize the serviceable life of existing assets. For example, as mentioned above, the utility will rebuild a deteriorated vault roof, extending the useful life of the entire vault.

D3.1.2 Asset Replacement Practices

The decision to replace an asset can result from many drivers, including asset failure, deterioration and failure risk, functional obsolescence, historical performance, standards alignment, planning and execution efficiencies, capacity requirements, and third-party requests.

Failure, failure risk, and functional obsolescence are the three most significant trigger drivers for asset replacement for Sustainment and Stewardship investments. Renewal-driven replacement practices for specific asset classes can range from primarily reactive replacement, where replacement largely occurs when the asset has failed (i.e. it can no longer serve its intended function), to primarily proactive replacement, where the consequence of failure for an asset class (i.e. the asset's criticality) is high, making it unacceptable to run the asset to failure under most circumstances.

While a few asset classes are situated at the far ends of the reactive-proactive spectrum, Toronto Hydro manages most major asset classes using a blend of reactive and proactive replacement strategies. This approach reflects how the risk profile and specific performance challenges within and across asset classes evolves over time, particularly in a large, dense, and congested city served by a variety of highly utilized systems inherited from several predecessor smaller utilities. It also reflects variability in the location-specific criticality of individual assets across the system. The proportion of assets the utility replaces proactively is related to the utility's performance objectives and the risk assessments underlying projected performance.

The overall pace of asset replacement over time is also determined by long-term system stewardship objectives in accordance with good utility practice. As a steward of the grid, if Toronto Hydro expects a large demographic "wall" or "wave" of end-of-life assets approaching within a 10-15-year period, it has a responsibility to assess the impact and reasonability of smoothing out the investment profile. Practically this entails replacing a subset of the assets sooner, rather than waiting until the wave hits and being forced to replace all assets within a tighter window. This approach is preferred because it creates a more stable investment profile, leading to more realistic and efficient project resourcing and execution. It also has the benefit of yielding more predictable and stable rate impacts for customers. Increasingly, customers support investments that provide longer-term benefits. When specifically asked to make trade-offs between price and other outcomes (system health, reliability and efficiency) regarding these type of stewardship investments, the majority of customers surveyed agreed that Toronto Hydro's draft plan struck the right balance, with many customers expressing a preference for Toronto Hydro to spend more.[22]

The reverse of this dynamic is also relevant: if Toronto Hydro sees longer-term needs for an asset class easing-up over time, the utility may choose to slightly delay a proportion of necessary short-term investments, effectively accepting some short-term incremental asset failure risk in favour of a smoother investment profile and the related benefits. Note that with the emerging drive toward electrifying consumer loads (e.g. electric vehicles; heat pumps), Toronto Hydro anticipates that opportunities to defer asset replacement may be fewer in the future, since the utility is likely to face a higher rate of urgent low-voltage expansion needs (e.g. upsizing pole-top transformers to accommodate greater peak demand at the neighbourhood level).

Tables 2 to 6 below provide an overview of Toronto Hydro's current replacement practices for assets on each part of the distribution system.

[22] Exhibit 1B, Tab 3, Schedule 1

1 **Table 2: Summary of Overhead System Asset Replacement Practices**

Asset	Asset Replacement Practices
Poles	Toronto Hydro manages the risk profile of its pole population by proactively replacing poles in alignment with condition demographics and other risk factors (e.g. legacy asset replacement needs). Poles are replaced on an individual basis or as part of area rebuilds. Poles are prioritized for replacement based on condition, age, criticality, and relationship (e.g. proximity) to other high-risk assets. In the event poles fail while in service, Toronto Hydro replaces them reactively. Due to the urban environment in which Toronto Hydro operates, the utility has a very low risk appetite for catastrophic pole failure (i.e. collapse of pole) and designs its pole testing, inspection and reactive replacement programs to substantially mitigate this risk. During pole replacements, deteriorated and obsolete accessories such as porcelain insulators are also replaced because they are susceptible to contamination build-up, which can lead to asset failure and pole fires.
Pole-top Transformers	Toronto Hydro manages the risk profile of its pole-top transformer population through proactive and reactive replacement. The utility prioritizes transformers that present heightened failure risks based on inspection results, age, area reliability, and environmental risks (e.g. oil leaks containing polychlorinated biphenyls ("PCBs")). Due to the low individual criticality of a typical, PCB-free pole-top transformer, Toronto Hydro will generally replace these assets reactively or as part of a larger proactive area rebuild project when there are economies of scale. Toronto Hydro plans to replace the remaining "PCB at-risk" transformers in the distribution system to minimize failures and environmental risk. Toronto Hydro also expects that, due to the emerging pressures of electrification, space and capacity constraints will increasingly be a factor in the decision to schedule a pole-top transformer for proactive replacement.
Overhead Switches	Overhead switches are constantly exposed to harsh environmental conditions, and 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. Where appropriate, switches are replaced as part of a planned area rebuild, or else reactively upon failure due to age, condition, or external factors. Where safety risks are identified for a type or class of switches, the utility executes planned replacements of these assets to mitigate the risks.

Asset	Asset Replacement Practices
Overhead Conductors (primary and secondary)	Toronto Hydro does not have a dedicated proactive renewal strategy for overhead conductors. Where appropriate, conductors are replaced as part of a planned area rebuild (e.g. upgrade to tree-proof conductor in heavily treed areas) or reactively upon failure due to age, condition, or external factors. Toronto Hydro expects that, due to the emerging pressures of electrification, capacity constraints on the secondary conductor buses which supply low-voltage electricity at the neighbourhood level will increasingly be a factor in the decision to schedule renewal projects.

1 **Table 3: Summary of Underground System Asset Replacement Practices**

Asset	Asset Replacement Practices
Underground Cables (Polyethylene)	Toronto Hydro manages the risk profile of its underground cable population by both proactively and reactively replacing polyethylene (e.g. cross-linked polyethylene ("XLPE")) cables. The utility proactively replaces aged or poor performing cables through neighbourhood rebuild projects to manage significant reliability risks associated with these assets, mainly targeting poor performing direct-buried cables in the Horseshoe area. Otherwise, if these cables fail while in service, they are repaired or replaced reactively. With the introduction of a new Cable Diagnostic Testing program, Toronto Hydro is leveraging new forms of asset condition information to prioritize cable and cable accessory replacements both reactively and on a planned basis.
Underground Cables (Lead)	Underground lead cables have traditionally been replaced reactively on the downtown underground distribution system. However, with increasing reliability, safety, and operational risks associated with lead cables (i.e. leaking cables, congested cable chambers, increasing numbers of splices, dwindling supply and expertise), Toronto Hydro started to proactively replace paper-insulated lead-covered cables and asbestos-insulated lead-covered cables in 2020 and will continue to do so until the population is fully removed. The utility 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. Aside from the modest proactive investments that are planned for the 2025-2029 period, these cables are repaired or replaced reactively when they fail while in service.

Asset	Asset Replacement Practices
Underground switches	Toronto Hydro manages the risk profile of underground switches by proactively replacing them, taking into consideration age, condition, and failure impact. Toronto Hydro also plans to replace switches as part of area rebuild projects. Otherwise, switches that fail while in service are replaced reactively.
Underground Transformers	Toronto Hydro manages the risk profile of its underground transformer population through proactive and reactive replacement. Underground transformers are replaced as part of planned area rebuilds or on an individual basis if they pose an environmental risk due to the risk of leaking oil containing PCBs and are at or past their useful life and/or in deteriorating condition. Otherwise, transformers that fail while in service are replaced reactively. Toronto Hydro expects that, due to the emerging pressures of electrification, constraints on the secondary distribution system which supplies low-voltage electricity at the neighbourhood level will increasingly be a factor in the decision to schedule renewal projects.
Underground Legacy Switchgear	Historically, Toronto Hydro has replaced underground legacy switchgear in customer-owned vaults reactively. However, due to the growing number of deficiencies where repairs are not an option and require replacement due to obsolescence, the utility is introducing proactive replacement of these legacy assets starting in 2025. Toronto Hydro plans to target the worst condition and most critical assets to maintain reliability performance and reduce safety risks, prioritizing them according to condition, inspection and maintenance history, and past reliability.
Cable Chamber	Toronto Hydro manages the risk profile of its underground cable chambers by proactively replacing cable chambers in HI5 and HI4 condition due to the growing number of deteriorating chambers and the complexity of chamber reconstruction work. Cable chambers are also prioritized based on the types of customers and thermal loading of feeders. Otherwise, cable chambers that fail while in service are addressed reactively. The utility plans to proactively replace cable chamber lids to address public safety risks in high traffic areas.

Asset	Asset Replacement Practices
Underground Residential Distribution ("URD")	Toronto Hydro manages the reliability performance for customers served by the unique URD system by proactively replacing URD assets. Toronto Hydro targets critical and obsolete URD assets in deteriorating and poor condition or past their useful life such as switching and non-switching vaults, switches, and transformers that contribute to the deterioration of system reliability. The utility prioritizes URD replacement projects based on the condition of civil roofs as deficient roofs pose an immediate risk to the public. Otherwise, assets that fail while in-service are replaced reactively.

1 **Table 4: Summary of Network System Asset Replacement Practices**

Asset	Asset Replacement Practices
Network Units	Toronto Hydro manages the risk profile of its network unit population by proactively replacing units in alignment with condition demographics and other risk factors (e.g. safety and environmental risks). The utility proactively replaces network units with a higher risk of failure due to age, condition, obsolescence, or location (i.e. prone to flooding). Older units with obsolete "non-submersible" protectors, which make them susceptible to water ingress causing failure, are generally beyond their useful life and are at risk of leaking oil containing PCBs. The utility is aiming to reduce and eventually eliminate the population of non-submersible units due to increasing risks of flooding. Otherwise, units that fail while in service are replaced reactively. Toronto Hydro continues 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 Vaults	Toronto Hydro manages the risk profile of its network vault population by proactively replacing vaults or vault roofs in alignment with condition demographics and other risk factors (e.g. safety risks). Due to the complexity of vault rebuild projects, Toronto Hydro must maintain a steady pace of renewal targeting the worst condition locations. Vaults are prioritized primarily based on condition and the associated safety risks of structural deterioration, customers served, and external factors (i.e. road moratoriums). If a deteriorated vault is no longer needed due to load displacement, then the utility will decommission it. Otherwise, vaults that fail while in service are addressed reactively.
Network Cables	See Underground cables – polyethylene and lead.

1 **Table 5: Summary of Stations Asset Replacement Practices**

Asset	Asset Replacement Practices
Transformer Station ("TS") Switchgear	Toronto Hydro manages the risk profile of its TS switchgear population by proactively replacing assets to manage overall switchgear demographic risk and system reliability. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Existing units are often difficult and infeasible to safely maintain due to their design, and therefore, proactive replacement is preferred to resolve maintenance issues. Asset replacements need to be done proactively, as they have long lead times to procure (e.g. 12-18 months), and design and construct (e.g. 3-4 years). Replacement prioritization is dependent on various factors, including: age, enclosure construction, load, arc flash rating, breaker condition, obsolescence, and safety. These assets can fail while in service, and in such situations, customers may experience long outages while Toronto Hydro restores power and subsequently repairs or replaces the failed switchgear reactively.
TS Oil Circuit Breakers (KSO)	Toronto Hydro manages the risk profile of its TS oil circuit breaker population by proactively replacing assets. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Asset replacements need to be done proactively as they have long lead times. Toronto Hydro replaces TS KSO oil circuit breakers based on age, condition, load, obsolescence, and safety and environmental risks (i.e. oil containing PCBs). Otherwise, assets are replaced reactively when they fail while in service.[23] Given the above risks, Toronto Hydro plans to remove all remaining KSO Oil circuit breakers from the system in the 2025-2029 period.
Municipal Station ("MS") Switchgear	Toronto Hydro manages the risk profile of its MS switchgear population by proactively replacing them. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Asset replacements need to be done proactively due to long lead times. Existing units are often difficult and infeasible to safely maintain due to their design, and therefore, proactive replacement is preferred to resolve maintenance issues. Toronto Hydro replaces MS switchgear based on age, breaker condition assessment results, type of circuit breaker, load, the obsolescence of the asset, resiliency of the surrounding distribution system to withstand switchgear failures, and the safety and reliability risks they present. New MS switchgears are arc-resistant. When these assets fail while in service, Toronto Hydro will first attempt to repair the unit, but depending on the severity of the fault, may replace it reactively.

[23] *Supra* note 16.

Asset	Asset Replacement Practices
MS Primary Supply	MS primary supply assets (disconnect switches, cables, and circuit breakers) are proactively replaced to maintain overall condition demographics and reliability. MS primary supply assets are replaced proactively as part of MS power transformer replacement projects and may be included as part of switchgear replacement projects. Prior to 2019, power transformer replacements were typically completed without replacing their MS primary supply. Toronto Hydro proposes to continue to replace the primary supply at MSs 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. MSs targeted for primary supply replacement are prioritized based on failure risk as determined by age and configuration (e.g. direct-buried cable). It takes three months to reactively replace a failed primary supply.
Power Transformers	Toronto Hydro manages the risk profile of its power transformers by proactively replacing them to manage overall demographic risk and system reliability. Power transformers require long lead times (e.g. 12 months) to procure, design and construct and therefore need to be replaced as part of a steady proactive renewal program. These assets are prioritized based on condition assessment, age, dissolved gas analysis, load, and resiliency of the surrounding distribution system to withstand transformer failures. Toronto Hydro plans to increase pace of power transformer replacement to address an increasing power transformer failure rate.
Station Service Transformers ("SSTs")	Toronto Hydro replaces SSTs proactively to manage age demographics and maintain reliability on the system. Asset replacement also requires long lead times and as a result, needs to be done proactively. Units are prioritized based on their age and associated environmental risk (i.e. risk of oil containing PCBs). Once these assets fail in service, the station service supply cannot afford to experience a subsequent failure as that failure would render the station inoperable. Moreover, any planned renewal or maintenance work of ancillary systems may be delayed.
Remote Terminal Units ("RTUs")	Toronto Hydro replaces functionally obsolete RTUs proactively as they are beyond their useful life, and no longer supported by their manufacturers. These assets can be repaired within a two-week period; however, repairs cannot be maintained over the long term due to the scarcity of spare parts. These assets also have a long replacement time (e.g. six months) and are therefore difficult to replace reactively. These assets are prioritized based on age, number of customers connected, load and failure rate.

Asset	Asset Replacement Practices
Relays & Copper Communication Cable	Toronto Hydro replaces relays proactively, mainly driven by obsolescence and the need to support grid modernization, but also driven by failure risk due to age. Copper communications cables are replaced proactively with fiber to mitigate the failure risk associated with older cables and to allow Toronto Hydro to have complete control, since many of the copper communication cables in the system are owned by third-parties. Assets are prioritized according to the number of customers and load connected, and failure rate of the station.
Direct Current ("DC") Battery Systems	Toronto Hydro replaces and maintains DC battery systems to ensure they can supply power to the station for eight hours (as mandated by the Transmission System Code). Replacement of the assets is prioritised based on functional obsolescence, age, and condition of the asset.
AC Panels	Toronto Hydro proactively replaces AC panels to mitigate failure risk of obsolete and end-of-life assets. An AC panel failure has a large impact because they supply all the station loads such as heating, cooling, lighting, ancillary equipment and DC charging systems with no backup supply in case of failure. AC panel replacements are prioritized based on age and the number of customers connected to the station.

Table 6: Summary of Metering Asset Replacement Practices

Asset	Asset Replacement Practices
Meters	Toronto Hydro replaces meters proactively at or beyond the end of their useful life to manage risk of failure and customer billing interruptions. Meters are replaced reactively if they fail to read or communicate or suffer complete failure. Reactive meter replacement consists of the replacement of defective metering equipment in the field including: smart meters, suite meters, interval meters and primary meters.

D3.2 Asset Lifecycle Risk Management Policies and Practices

Customer-focused outcome measures such as system reliability, safety incidents, connections efficiency, and oil spills are lagging indicators of system performance. These measures are essential to understanding the actual experience of customers, stakeholders, employees, and the general public in relation to the distribution system. However, certain lagging measures, by their nature, can be difficult to directly influence through actions taken in the near-term. This is especially true for measures that are influenced by asset failure. Toronto Hydro manages hundreds of thousands of distribution assets that are typically in service for decades. These assets can fail in a variety of ways at any point in their lifespan, and it is impossible to know with precision exactly when failure will occur. Therefore, in the daily effort to direct expenditures toward cost-effective interventions that will drive performance outcomes, Toronto Hydro must rely on risk – a leading indicator of performance – to make informed investment decisions.

As a large urban utility with a highly utilized system and a significant asset renewal need, risk assessment is essential to ensuring that system reliability and other outcomes can be maintained within a constrained expenditure plan. Risk assessments are also used to determine areas of the system that would benefit the most from investments in grid modernization.

This section outlines Toronto Hydro's lifecycle risk management methods and practices for its distribution assets, detailing the utility's risk assessment frameworks, including key considerations in risk evaluation, and typical risk mitigation approaches. Capacity related risk is discussed separately in Section D3.3.

D3.2.1 Overview of Risk Assessment Methods

Toronto Hydro's risk assessment framework consists of the following key elements:

- Probability of Failure;
- Consequence of Failure; and
- Risk Analysis.

Details of each key element follows.

D3.2.1.1 Probability of Failure

Probability (i.e. likelihood) of failure ("PoF") is an important consideration in determining whether asset intervention is necessary. This section focuses upon three key forms of analytics that Toronto Hydro uses to enable PoF evaluation: (i) Asset Condition Assessment ("ACA"); (ii) predictive failure modelling; and (iii) Historical Reliability Analysis.

1. Asset Condition Assessment ("ACA")

As explained in Section D1 and in Appendix A to this Section, Toronto Hydro employs an ACA methodology to monitor the condition of various key asset classes within its system and produce a Health Score to support project planning. The ACA allows Toronto Hydro to use data collected through inspections to produce a relative numerical representation of an asset's condition, considering key factors that affect its operation, degradation, and lifecycle.

Toronto Hydro uses ACA to support tactical and strategic investment planning decisions. Planners use inspection data and health scores – in combination with other information and professional judgement – to prioritize assets for tactical intervention in the short- to medium term. This includes identifying priority deficiencies that require reactive or corrective action, and prioritizing assets for planned renewal projects in a given budget period. At a strategic level, Toronto Hydro uses ACA results to examine condition demographics and trends within major asset classes to support the development of longer-term investment plans within the annual Investment Planning & Portfolio Reporting ("IPPR") Process.

The ACA model that Toronto Hydro has implemented is the Condition-Based Risk Management ("CBRM") methodology. This methodology was developed and adopted by the major utilities in the United Kingdom in collaboration with the regulator, the Office of Gas and Electricity Markets ("Ofgem").[24] The methodology provides a health score for every applicable asset based on the most recent inspection information. The methodology also projects Future Health Scores for assets, which provides intelligence on asset demographics that the utility leverages to evaluate proposed investment strategies over longer periods. Since the adoption of CBRM in 2017, Toronto Hydro's Health Score calculations and projection methodologies have remained largely consistent, with the

[24] The specific implementation of CBRM used by Ofgem for regulatory purposes is called the Common Network Asset Indices Methodology, or "CNAIM".

exception of certain targeted adjustments to reflect inspection program changes and to ensure the model is producing results that are aligned with field observations.

The general approach used to produce the health score for each asset is illustrated in Figure 3.

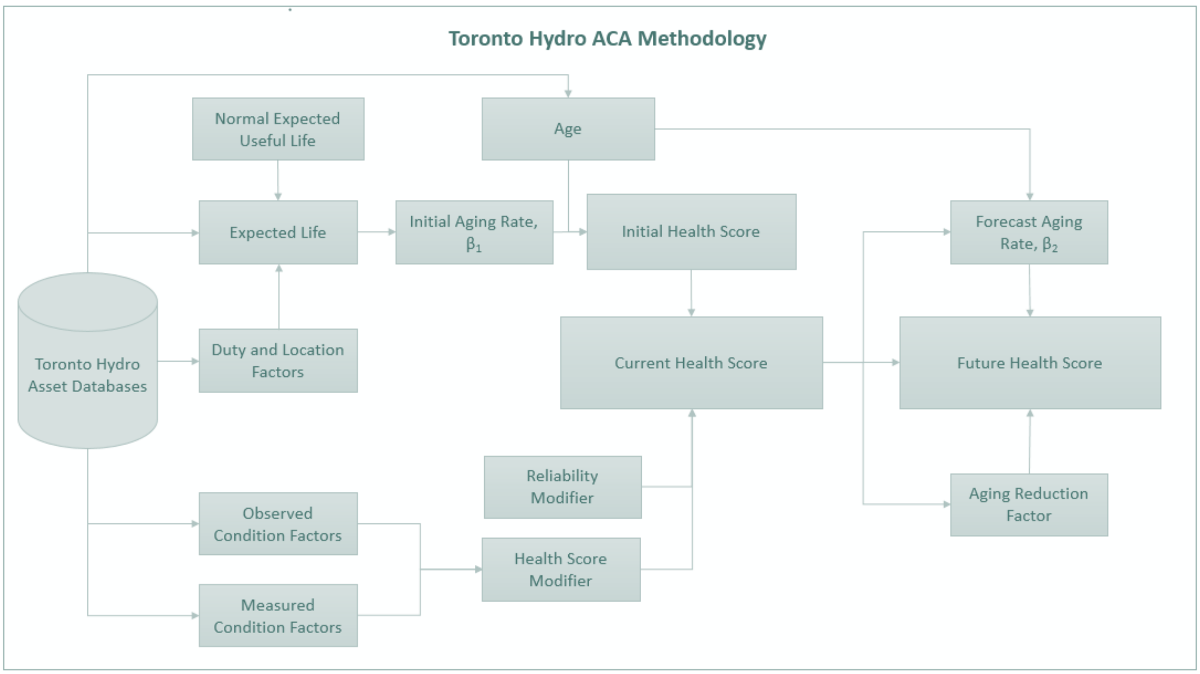


Figure 3: Asset Condition Assessment Process as Part of ACA

ACA results (i.e. Health Scores) for a particular asset class are grouped into five Health Index ("HI") bands that represent key stages of an asset's lifecycle, ranging from new or like new condition to the stage where asset degradation is significant enough to warrant urgent attention. Toronto Hydro uses asset health demographics and the underlying inspection details during the project scope development phase of IPPR, as outlined in Section D1. This enables planners to assess the relative probability of failure of their assets in the short and mid-term timeframe based on the HI band. The bands are defined as per Table 7 below.

Table 7: Health Index bands and definitions

HI Band	Lower Limit of Health Score	Upper Limit of Health Score	Definition
HI1	≥ 0.5	< 4	New or good condition
HI2	≥ 4	< 5.5	Minor deterioration; in serviceable condition
HI3	≥ 5.5	< 6.5	Moderate deterioration; requires assessment and monitoring
HI4	≥ 6.5	< 8	Material deterioration; consider intervention
HI5 (Current Health)	≥ 8	≤ 10	End of serviceable life; intervention required
HI5 (Future Health)	≥ 8	≤ 15	

Asset classes with HI scores are shown in Table 8 below.

Table 8: Assets Evaluated in the ACA

Switches	Breakers	Vaults	Transformers	Other
• Overhead Gang-Operated • SCADA-Mate • Air-Insulated Padmount • SF_6-Insulated Padmount • SF_6-Insulated Submersible • Air-Insulated Submersible	• 4 kV Oil Circuit (MS) • KSO Oil Circuit (TS) • SF6 Circuit (TS) • Vacuum Circuit (MS & TS) • Air Magnetic Circuit (MS & TS) • Airblast Circuit (MS & TS)	• ATS • CLD • CRD • Network • Submersible Switch • URD	• Station Power • Network • Submersible • Vault • Padmount	• Wood Poles • Network Protectors • Cable Chambers

The ACA output is essential in two respects. First, the ACA produces a relative outlook of the population's condition for each individual asset class within the program. Second, the ACA highlights trends in the condition of asset populations. For system planners, these insights provide an indication of the relative probability of failure for an asset and how failure risk within an asset population is evolving over time. Being aware of these issues and trends allows Toronto Hydro to balance capital investments against continuing maintenance. More generally, the ability to compare current and future HI results for an asset class can support decision-making when developing expenditure plan envelopes for longer-term investment programs. In its 2025-2029 Distribution System Plan ("DSP"), Toronto Hydro has used this information to compare proposed investment levels against current and projected volumes of assets in the two worst health bands ("HI4") and ("HI5").

As highlighted in Section D1.3.2.1, and as a next step in the evolution of the utility's ACA approach, Toronto Hydro is in the process of implementing the Probability of Failure component of the broader CBRM methodology. This extension of the methodology will allow the utility to convert an asset Health Score (which serves as an indirect indicator of relative PoF) into an absolute PoF value which can then be applied in quantitative risk-based decision-making frameworks, including the utility's value framework for capital investments. The role of PoF in these frameworks is discussed further in the following section.

2. Predictive Failure Modelling

Predictive failure modelling is another essential component of Toronto Hydro's approach to risk-based asset management. Predictive failure modelling involves the derivation of hazard rate functions for each asset class and the application of said functions to existing and future asset population demographics to produce a predicted number of failures per year. The utility leverages these failure models to support risk-based investment decision-making and system performance projections.

A hazard rate, commonly used in reliability engineering, represents the instantaneous likelihood of failure given that an asset has survived up to a particular time. To the extent that North American distribution utilities like Toronto Hydro have pursued quantitative risk-based asset management tools in recent decades, they have typically relied upon age-based hazard rate functions to produce quantified PoF values. In Toronto Hydro's case, while age-based PoF is currently the more mature mode of analysis for analytics such as reliability projections, the utility is in the process of introducing condition-based PoF as an enhancement to its decision-making tools and analytics. As noted above, this condition-based PoF is an extension of the Health Score concept within the CBRM framework.

As discussed in Section D1.2.1.1, as part of its ongoing multi-year effort to implement an industry leading Engineering Asset Investment Planning ("EAIP") platform, Toronto Hydro is developing a custom value framework which assigns relative value to investments based on their likely contribution to Toronto Hydro's key performance outcomes. For many of these investments, including a majority of the System Renewal programs, this value framework is built directly upon the utility's CBRM framework, ensuring that projects will be consistently prioritized on the basis of their verifiable contributions to mitigating quantifiable condition-based asset risk. The condition-based PoF values will serve as an important input to this framework.

The role of predictive failure modelling in reliability projection procedures is discussed in Section D3.2.1.3.

3. Historical Reliability Analysis

The third component of Toronto Hydro's probability of failure analysis involves the analysis of historical reliability data in order to identify failure trends for asset populations and areas of the system.

Toronto Hydro's reliability analytics system stores historical outage information which the utility uses as a tool in developing capital spending. By continuously analyzing the reliability performance of its circuits and substation assets, Toronto Hydro can identify areas experiencing reliability issues, which may be caused by asset deterioration or legacy design related issues. Toronto Hydro utilizes the following ten major cause codes to classify historical outages:

- Adverse Environment;
- Adverse Weather;
- Defective Equipment;
- Foreign Interference;
- Human Element;
- Lightning;
- Loss of Supply;
- Scheduled Outages;
- Tree Contacts; and
- Unknown.

From a probability of failure perspective, this data can be used to identify those asset classes and sub-classes, as well as parts of the system that experience a high frequency of failure. In specific scenarios, historical reliability performance can be a strong indicator of future issues. As an example, reliability data has been utilized as part of Toronto Hydro's planning procedures to identify feeders containing the most problematic direct-buried underground cables.

D3.2.1.2 Consequences of Failure

When determining the risk of asset failure, there are two components considered; the probability of failure (explained in Section D3.2.1.1) and the consequences of failure. Consequences are generally broken down into major categories (e.g. safety consequences) that align with Toronto Hydro's corporate pillars and outcomes framework.

1. Reliability

Toronto Hydro evaluates reliability consequences associated with its assets using a mix of quantitative and qualitative information:

- Reliability performance analysis;
- Customer engagement and consultation activities;
- Key account customer program and responses to customer calls and complaints;
- Reliability analysis identifying long-duration impacts; and
- Application of customer interruption costs.

Table 9 provides additional information related to each of the aforementioned tools and approaches.

1 **Table 9: Summary information used to establish Reliability Consequences**

Tool or Approach	Summary
Reliability Performance Analysis	As explained above in Section D3.2.1.1, Toronto Hydro's reliability analytics system keeps detailed records on outage events. The utility mines this data to gather insights into the frequency and consequences of different kinds of events, including various modes of asset failure for the different types of assets on the distribution system. This analysis is useful for developing statistical averages and ranges that are applicable in risk modelling (e.g. average number of customers interrupted and average duration of an outage for a pole-top transformer failure on the 27.6 kV system). It is also useful in determining which asset sub-types and specific parts of the distribution system are exhibiting higher than average reliability consequences (e.g. quantifying the higher average outage duration consequences for events on the rear lot system). Toronto Hydro leverages these reliability analytics both directly and in combination with other leading and lagging indicators to establish the relative consequence of failure for different assets, and to establish investment priorities. Reliability analytics are also important for more dynamic, "in year" management of customer reliability impacts. For example, a distribution feeder that is experiencing a rash of outages in the short-term will be monitored more closely and intervened upon more urgently as a potential "worst performing feeder." Flagging a feeder as a worst performer effectively elevates the consequence of failure of each subsequent outage, since further deterioration in performance would violate management's standards for acceptable reliability.

Tool or Approach	Summary
Network/Reliability Consequence of Failure ("CoF")	As part of its ongoing efforts to implement an EAIP system, Toronto Hydro is developing a custom Value Framework that is aligned with its corporate pillars and outcomes framework. Network/Reliability CoF is one component of the framework. The Network/Reliability CoF models the customers interrupted and duration impact of asset failure, leveraging Customer Interruption Costs ("CIC") to quantify the cost of failure to customers. CICs represent a measure of monetary losses for customers due to an interruption of electric service. CIC values are calculated in two parts: Event cost and Duration cost. The Event cost represents the impact to customers due to the occurrence of the outage. Within the Value Framework, the event cost is calculated by multiplying customer interruption costs with total customers impacted for an asset failure. The duration cost represents the costs incurred as the length of the outage increases, calculated by multiplying the duration cost by the average time to restore power after an asset failure, considering time required for switching operations and repair or replacement. This component of the value framework, when combined with the PoF, will supersede the utility's legacy Feeder Investment Model as the primary means of assessing the impact of asset failure through a fully quantified and probabilistic risk lens.

Tool or Approach	Summary
Customer Engagement	Toronto Hydro executes a variety of customer engagement programs designed to establish interactions with customers that provide the utility with qualitative and quantitative insight into the customer's experience, needs, preferences, and priorities. This information can come through various channels, ranging from ad hoc customer interactions, to periodic engagements with larger customers, to infrequent but highly comprehensive investment planning-related engagements and surveys. Key examples include: • **Key Account Customer Program:** Toronto Hydro's Key Account Customers are those customers who have critical loads, including: customers who have electricity use greater than one MW at a single site or combined across a number of sites, priority loads such as hospitals and financial institutions, essential public services including the Toronto Transit Commission, schools, and developers. Toronto Hydro manages a key account customer program for these customers to address specific concerns and issues in a timely manner. The utility proactively engages with these customers on a wide range of topics including resolving issues related to reliability and power quality. These engagements help Toronto Hydro to calibrate its decision-making to ensure it is aligned appropriately with the customer's experience of outage and power quality events. • **Rate Application Customer Engagement:** Every five years, in preparation for its rate-setting application cycle, Toronto Hydro undertakes extensive Customer Engagement as part of business planning. This process produces a detailed and comprehensive view of high-level customer preferences when it comes to key outcomes including reliability and resiliency. Toronto Hydro uses this information to calibrate its investment strategy and ensure general investment pacing and prioritization is reflective of the customer's willingness to pay to avoid the reliability consequences of system faults.

2. Environmental

Toronto Hydro takes all reasonable actions to reduce the risk of asset failures resulting in adverse effects to the environment. Beyond the potential environmental impacts that can result from certain asset failure modes, Toronto Hydro can face associated consequences such as potential non-compliance or breach of regulatory obligations, which in turn can have severe reputational and financial implications.

Toronto Hydro's major environmental concerns include: (i) oil or SF_6 gas leaks of all types; (ii) reducing greenhouse gas emissions ("GHG"); and (iii) mitigating the use of substances like asbestos, lead, and PCBs in its equipment. Through planned asset inspections, oil deficiencies in the system are identified and necessary corrective action is taken. Toronto Hydro is continuously striving to mitigate environmental risks such as the risk of oil spills, while simultaneously ensuring compliance with federal, provincial, and municipal regulations pertaining to the release of oil into the environment. Similarly, through inspection and renewal programs, assets containing lead, asbestos, and PCBs are identified and included for replacement with standardized and less harmful equipment. Toronto Hydro will mitigate the risk of oil spills containing PCBs on its overhead, underground and network systems by 2025 by replacing at-risk assets. Toronto Hydro is also acting to reduce SF_6 gas leakage into the environment. For example, the latest generation of SF_6-insulated switches Toronto Hydro installs have welded viewing windows that mitigate SF_6 gas leakage into the environment. Moreover, the utility is trialing Solid Dielectric ("SD") switchgear as an alternative to SF_6 insulated gear.

Toronto Hydro is including Environmental CoF as another component within its custom value framework as part of its EAIP implementation. The Environment CoF will reflect the above considerations, quantifying the impacts of oil and SF_6 gas leaks or contamination, GHG emissions, and equipment disposal. In addition, considerations for increased consequence due to the presence of substances such as PCBs will also be made in determining the overall environmental consequence of asset failure.

3. Safety

Mitigating safety risks to Toronto Hydro employees and the general public is the highest priority objective of Toronto Hydro's Asset Management process. As highlighted in Section E2.3, customers consider the safety of the system to be a default priority for the utility. Public and employee safety is the overarching priority of Toronto Hydro and is built into its culture, operations, and decision-making frameworks. Toronto Hydro continues to strive for zero public and employee safety incidents each year. Moreover, one of Toronto Hydro's objectives is to comply with all safety regulations and standards over the 2025-2029 period.

Toronto Hydro is implementing Safety CoF within its custom value framework. Safety CoF will quantify impacts to both public and crew safety, including direct and indirect costs associated with death or serious injuries, lost time injuries, and third- party damages resulting from asset failure.

Factors that impact the severity or probability of an injury, such as an asset's proximity to high traffic areas or the size of an asset, will also be considered within the overall Safety CoF.

Nearly all of the utility's asset renewal, service, and maintenance activities are driven in part (and sometimes entirely) by safety considerations. For example, Toronto Hydro's programs to reduce and eliminate obsolete legacy equipment and configurations are driven in large part by known safety risks and related operational restrictions. Examples of these activities include:

- Eliminating safety risks related to Electrical Utility Safety Rules ("EUSR") compliance issues associated with legacy box construction configurations;
- Reducing public and employee exposure to safety risks as a result of outages in rear lot configurations;
- Addressing emerging safety risks identified by the Electrical Safety Association ("ESA") such as potential fire risks at "Delta-Wye" locations; and
- Reducing public safety risk due to cable chamber lid ejections

Toronto Hydro's Environmental, Health and Safety ("EHS") and Standards functions, funded by the Human Resources and Safety program (Exhibit 4, Tab 2, Schedule 15) and the Asset and Program Management program (Exhibit 4, Tab 2, Schedule 9), have important roles in maintaining safe work practices, implementing engineering controls, and adhering to requirements related to environmental protection and occupational health and safety. In the event of an incident relating to asset failure(s) where there is an environmental or safety risk, staff responsible for the aforementioned functions (i.e. EHS and Standards) will investigate to determine the defect in the equipment. EHS bulletins will be released for immediate notification of potential workplace hazards, accidents, injuries, near misses, environmental issues, and important information regarding accident prevention. If applicable, a new standard for a replacement product will be developed.

If the defective equipment poses a significant risk to the system, a capital or maintenance program would be proposed to replace the asset with new standardized equipment. For example, delta-wye corrective work under the Corrective Maintenance program,[25] addresses the potential hazard of fire and shock posed by three-phase grounded wye-connected secondary transformation with no grounded neutral conductor between the transformer's secondary neutral terminal and the

[25] *Supra* note 8.

customer's service entrance equipment. This issue was flagged by the ESA and this work enables compliance to ESA requirements.

4. Public Policy

In addition to addressing customer reliability, environmental, and safety concerns, Toronto Hydro must remain compliant with public policies and regulations. Certain circumstances or asset failures carry with them the risk of putting Toronto Hydro in violation of public policies. Some relevant public policies include:

- Managing asbestos as per the *Ontario Occupational Health and Safety Act* as well as the *Canadian Environmental Protection Act* to eliminate and phase out asbestos;[26]
- Reducing the risk of PCB leakage into the environment and eliminating all PCB containing equipment greater than 50 ppm to comply with PCB Regulations as defined in the *Canadian Environmental Protection Act*, SOR/2008-273,[27] and in the City of Toronto *Municipal Code,* Chapter 681 – Sewers;[28] and
- Ensuring compliance with *Ontario Regulation* 22/4,[29] and safety performance as measured through the Serious Electrical Incidents Index.

5. Financial

Some of the consequences of asset failure discussed above can also have significant financial impacts for Toronto Hydro. Financial CoF will be integrated within Toronto Hydro's value framework in order to reflect the direct financial costs of failure required to replace or repair an asset. Asset failure can also cause outages disrupting the normal operations of businesses, damage the surrounding area (e.g. through oil spills), and create safety risks. These can increase the risk of Toronto Hydro incurring additional costs for environmental remediation, fines, and legal costs in the form of claims and any resulting litigation, in addition to asset replacement or repair costs. The potential financial impacts of failure differ depending on the nature of the failure and from asset to asset because assets operate under varying conditions and loadings.

[26] *Occupational Health and Safety Act* , R.S.O. 1990, c. O.1 and *Canadian Environmental Protection Act,* 1999.
[27] PCB Regulations (SOR/2008-273), under the *Canadian Environmental Protection Act,* 1999.
[28] Toronto Municipal code, Chapter 681 Sewers (July 27, 2023).
[29] O. Reg. 22/04: Electrical Distribution Safety, under Electricity Act, 1998, S.O. 1998, c. 15, Schedule. A.

D3.2.1.3 Risk Analysis

The probability and consequence inputs, as identified in Sections D3.2.1.1 and D3.2.1.2 respectively, are used either individually, or in combination as part of analyses prior to arriving at risk-based decisions related to long-term and short-term asset management plans and investments. The risk of failure may be determined by using a combination of qualitative and quantitative methods. Various risk-based tools are utilized to provide multi-faceted perspectives that support and ultimately justify investment decisions. The following subsections provide insight into the various risk-based decision-making tools that are used at Toronto Hydro.

1. Quantified Risk-Based Analysis

As mentioned in Section D3.2.1.1, Toronto Hydro is taking the next step in the advanced implementation of its risk frameworks by developing a custom value framework to inform its EAIP platform. The value framework will allow a quantitative assessment of the relative value for projects based on their alignment to key outcomes. It integrates risk assessments in quantifying the value for projects along with other value drivers, allowing the utility to consider the overall value of investments in decision-making and produce an optimized set of projects to achieve key performance outcomes.

Toronto Hydro’s value framework, especially as it relates to Sustainment and Stewardship investments, is rooted in the CBRM methodology and is informed by both the probability and consequence of failure inputs discussed in Section D3.2.1.1 and D3.2.1.2 above. The value framework integrates incremental development within its ACA methodology (such as condition based PoF curves) along with quantified consequence of asset failure (CoF) as detailed in Section D3.2.1.2 above, specifically:

- Network/Reliability Consequences;
- Environmental Consequences;
- Safety Consequences; and
- Financial Consequences

The custom Value Framework embedded within its EAIP platform will allow Toronto Hydro to assess and understand the risk profile of its assets in order to support decision-making as it relates to its short- and long-term investments, including assessments of value for alternative approaches for intervention. Comparing the change in risk mitigation (value of investment), along with other value drivers, over multiple years allows Toronto Hydro to evaluate trade-offs between outcomes, resource requirements, and budgetary pressures year over year. Subsequently, Toronto Hydro can leverage the capabilities of its EAIP tool to establish an optimized set of projects to achieve performance outcomes in each year that is aligned with its outcomes framework.

2. Reliability Projections

In order to conceptualize the impact of investment programs, Toronto Hydro performs an analysis of historical system reliability and produces a reliability projection ("RP"). The RP provides a risk-based view utilizing the major reliability indices (e.g. SAIFI, SAIDI) and enables informed decision making for capital investments. The RP is based upon:

a) asset demographics data and associated failure projections;
b) historical reliability performance; and
c) planned program investments.

The system historical reliability category is broken into individual cause codes and in some cases (e.g. defective equipment) down to the asset level. For Defective Equipment, Toronto Hydro projected failure and outage impacts at an asset class level based on associated demographics, historical reliability, and the expected benefits of it's 2025-2029 planned Sustainment and Stewardship investments. The utility applied a historical five-year average to project other cause codes. It also included projections for the reliability related benefits of Grid Modernization investments.

As part of the RP process, a reactive replacement scenario is produced, to estimate the performance of the current system without proactive intervention. The scenario depicts what is expected if assets remain in service and naturally reach end-of-life. Asset failures increase as they are operated beyond useful life and in deteriorated conditions, contributing to worsening reliability. This provides a reliability centric risk view for Toronto Hydro.

In addition to the reactive replacement approach, Toronto Hydro produces a scenario to project the reliability impact of the Sustainment and Stewardship programs and reliability related benefits of grid modernization programs on the system. This is determined by reviewing each planned program for reliability benefits, improved operational flexibility, and influences on asset demographics. The program benefits are applied to the individual outage cause codes (listed above in section D3.2.1.1) based on their level of impact on reliability. The results are then aggregated to the system level to obtain the final system-wide reliability projections. RP analysis and results used in the development of the capital expenditure plan are discussed in Section E2.2.2.3.

In general, this conceptual analysis is used by Toronto Hydro to evaluate the reliability impact of the proposed capital expenditure plan. This analysis also supports Toronto Hydro in setting targets for reliability performance as part of its Custom Performance Measures for SAIDI (excluding Loss of Supply, Major Event Days, and Scheduled Outages) and SAIFI (Defective Equipment).[30]

3. Worst Performing Feeder ("WPF")

Toronto Hydro assesses the overall performance of the system in order to improve service reliability for customers supplied by poorly performing feeders. The utility identifies feeders performing poorly over a rolling 12-month period and performs work to mitigate further interruptions. Toronto Hydro defines a feeder as performing poorly when it meets, or is trending towards meeting criteria below:

- Non-key account feeders that are at risk of experiencing seven or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of seven or more, or "FESI-7").[31]
- Key Account feeders at risk of experiencing six or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of 6 or more, or "KAWPF-6").
- Key Account feeders that contain large critical customers with Ion meters installed at their service entrance that have their operations negatively impacted by multiple sustained or momentary interruptions and/or power quality issues. These customers are typically large manufacturing facilities or hospitals, which are sensitive to voltage sags and momentary outages.
- Feeders that are experiencing systemic issues in a localized area that are resulting in, or at risk of resulting in multiple sustained or momentary interruptions.

The WPFs in the system are typically addressed through a combination of short-term intervention (both capital and maintenance) and complementary planned renewal work. Additional details

[30] Exhibit 1B, Tab 3, Schedule 2.

[31] Note that, with recent upgrades to the Network Management System and the ongoing transition to Oracle Utility Analytics for reliability analysis, Toronto Hydro is now capturing a greater number of very small outages. The utility is currently assessing the impact of this change on its FESI-7 measure (which counts individual outages equally, regardless of size) and may choose to redesign this feeder-based reliability the measure to more accurately reflect the experience of customers who are truly experiencing an unacceptable frequency of interruptions.

related to programs targeting worst performing feeders, which are in place to improve reliability and meet the needs of customers, may be found in Reactive and Corrective Capital program.[32] As a result of investments to improve the reliability of these feeders, sustained improvements have been achieved as illustrated in Exhibit 2B, Section C.

4. Enterprise Risk Management

Toronto Hydro considers a broad range of risks that the corporation faces through the Enterprise Risk Management ("ERM") process. Toronto Hydro's ERM framework has been designed to manage risks at the corporate level, and considers the risks facing individual asset classes and risks relevant to investment programs.

Toronto Hydro continuously works to identify and manage corporate risks that emerge from the asset base, and create new programs to manage these risks when prudent to do so. For example, various risks have been analyzed and managed using the ERM framework including risks posed by direct-buried cables, porcelain insulators, cable chamber lids, and secondary cables. The ERM framework groups such risk under categories such as "asset management risk" or "public safety risk". The ERM framework and the analytical results derived from the ERM process serve as another input into Toronto Hydro's overall risk assessment and management procedure. This input is available and updated regularly for monthly and annual tracking of risk mitigation measures while providing visibility into broader corporate risks.

5. Priority Deficiencies

When defective equipment is found, either through a planned inspection or following emergency response, the appropriate follow up actions are assigned based on the nature of the work. Toronto Hydro applies a risk framework to help prioritize repairs and corrective actions. In addition, the framework is useful for assessing risk trends related to both particular asset classes and system overall.

Toronto Hydro reviews all deficiencies to determine appropriate actions and the level of priority to be assigned to each deficiency. Prioritization of the asset deficiencies as part of the work request process is based on the urgency of the work and the risk it poses. The work requests are classified into three categories:

[32] *Supra* note 6.

- **P1**, requiring a resolution within 15 days;
- **P2**, requiring a resolution within 60 days; and
- **P3**, requiring a resolution within 180 days.

Toronto Hydro also identifies a P4 category of low priority deficiencies largely for the purposes of monitoring a deficiency, but no corrective work is issued. For additional details related to deficiencies, defective equipment, and prioritized reactive and corrective actions, please see the Reactive and Corrective Capital,[33] Corrective Maintenance,[34] and Emergency Response programs.[35]

6. Legacy Assets

Toronto Hydro's risk assessment frameworks include inventories of legacy assets and configurations that have been identified based on various factors (e.g. their likelihood of failure and resulting impact on system reliability, safety, or the environment). These assets and configurations are also typically functionally obsolete with limited or no support from manufacturers or third-party service providers. Toronto Hydro monitors these legacy assets to manage and minimize their associated risks to customers, employees, and the public. The utility evaluates legacy asset risk and performance over time, adjusting investment plans over the short, medium, and long-term to ensure the risks are being addressed at an appropriate and feasible pace. The reduction or elimination of these assets and the associated risks was a major contributing factor when developing the investment plans outlined in Section E of the DSP. For more information on Toronto Hydro's legacy assets, please refer to Section D2.

D3.2.2 Overview of Risk Mitigation Methods

Through its capital and maintenance investment plans, Toronto Hydro mitigates both the quantitative and qualitative risks identified above. Toronto Hydro manages risks by prudently investing in its assets while deriving value for customers. As such, the risk-based models and approaches described above are key inputs into the decision-making process for investment planning. Assets that pose a risk to the system are identified based on their contribution to the various risk factors discussed above as part of the IPPR process and grouped into investments categories.

[33] *Supra* note 6.
[34] *Supra* note 8.
[35] *Supra* note 5.

D3.2.2.1 Sustainment and Stewardship Investments

As part of Toronto Hydro's risk mitigation efforts, Sustainment and Stewardship investments form a significant portion of the utility's capital investments. These investments are geared towards maintaining the foundations of a safe and reliable system and standardizing outdated equipment. They aim to ensure long-term performance of Toronto Hydro's assets, maintain system reliability, and minimize asset failure risk. The Sustainment and Stewardship investment category also contains programs aimed at addressing the other risk areas identified in Section D3.2.1.2 and D3.2.1.3 above. Programs such as Area Conversions (Exhibit 2B, Section E6.1) are aimed at eliminating legacy designs along with their reliability and safety consequences. In addition, Sustainment and Stewardship programs inherently target assets that pose environmental risks, such as oil leaks, especially for equipment containing PCBs. They also include more specialized programs that address areas with high historical failures or failed assets, through programs such as the Reactive and Corrective Capital program.[36]

D3.2.2.2 Growth and City Electrification Investments

Growth and City Electrification investments allow Toronto Hydro to connect and serve growing demand for electricity as Toronto continues to grow, digitize and decarbonize key sectors of the economy. These investments ensure Toronto Hydro meets capacity and connection needs and is able to provide new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system. Toronto Hydro determines capacity and connection needs through the Stations Load Forecast, load connections forecasting, generations connections forecasting, and the Regional Planning process.[37] The Customer Connections program captures system investments that Toronto Hydro is required to make to provide customers with access to its distribution system, including enabling new or modified load and distributed generation connections to the distribution system.[38] Section D3.3 further discusses Toronto Hydro's policies and practices in regards to capacity planning and the connection of both load and generation customers.

D3.2.2.3 Modernization Investments

Modernization investments allow Toronto Hydro to adopt new technology to improve system performance and reduce costs over time, and to protect the system against intensifying threats.

[36] *Supra* note 6.
[37] Exhibit 2B, Section D4.
[38] Exhibit 2B, Section E5.1

Toronto Hydro invests in programs that allow for other cost-effective forms to mitigate the risks discussed in Section D3.2.1. For example, Toronto Hydro is investing in improving operational flexibility and observability through the System Enhancements program.[39] Installation of SCADA-Mate switches or reclosers allows Toronto Hydro to address reliability related risks, in a manner that compliments renewal activities in delivering the utility's overall reliability objectives.

Toronto Hydro is also investing in grid enhancement and modernization efforts to adapt to the changing needs of customers, environment, safety considerations, and stakeholders. The distribution grid faces pressure to support the energy transition and electrification such as the need to integrate increasing number of DERs and EVs in a safe and efficient manner. Toronto Hydro's Grid Readiness initiative aims to address the risk of increasing DERs and EVs proliferation. Moreover, Toronto Hydro's investments in Intelligent Grid initiative enhances observability and controllability of the grid, and mitigate risks around climate change and cybersecurity threats. For more information on the initiatives related to Grid Modernization, please refer to Exhibit 2B, Section D5.

D3.2.2.4 Maintenance and Refurbishment Activities

Toronto Hydro uses maintenance programs, as detailed in Exhibit 4, to both identify and mitigate risks in the system. Inspections are key in providing data inputs for risk analyses, including assessment of asset condition and identifying priority deficiencies that require intervention. This data provides Toronto Hydro with information on assets that is critical to decision making, such as the presence of oil leaks or other forms of equipment deterioration. In addition, maintenance programs can help maximize the life of assets, thereby managing the overall need for capital intervention. For example, treatment of wood poles helps protect against infestation and rot, reducing the probability of failure.

D3.2.2.5 Other Investments

Toronto Hydro must also invest to ensure it manages risks in terms of meeting the needs of its customers and stakeholders. For example, it must meet the expectations of regulatory bodies and governments with respect to policies. This includes proactive metering investments that ensure Toronto Hydro remains in compliance with the requirements set by Measurement Canada.

[39] *Supra* note 19.

D3.3 Asset Utilization Policies and Practices

This section highlights Toronto Hydro's policies and practices in regards to capacity planning and the connection of both load and generation customers. It details Toronto Hydro's process to assess capacity requirements, connections, and steps to mitigate risks.

D3.3.1 Capacity and Connections Capability Assessments

Toronto Hydro continues to monitor capacity related risks within its system from both a short- and long-term view point. This includes working with third parties such as the Transmitter (i.e. Hydro One Networks) and the Independent Electricity System Operator ("IESO") as required for planning purposes, for both load connections and generation connections.

D3.3.1.1 Distribution Capacity & Capability Assessments

1. **Peak Demand Forecasting**

Toronto Hydro uses a peak demand forecasting process to identify capacity constraints at substations within the system ("System Peak Demand Forecast"). This allows Toronto Hydro to maintain awareness of bus capacity as new connections are made and natural load growth (or reductions) occur. The System Peak Demand Forecast provides a near-to-medium term view of the station bus capacity so that appropriate plans can be made to accommodate varying growth within the system.[40]

In order to complete a ten-year System Peak Demand Forecast at the substation level, as shown in Figure 5, Toronto Hydro identifies the annual non-coincident peak loads (both summer and winter peaks) for each individual bus at its substations. These peak loads are then normalized based on historical temperatures at which they occur.

Following this, additional load growth is added to each bus considering economic variables. Toronto Hydro considered three new specific drivers in the development of the System Peak Demand Forecast: (i) hyperscale data centres, (ii) electrification of transportation, including EVs, and (iii) Municipal Energy Plans which include large anticipated connections in different areas of the city. In addition, all customer connection requests and planned permanent work such as load transfers and voltage conversions are added to each bus.

[40] See Exhibit 2B, Section D4.1.1 for a detailed description of Toronto Hydro's Peak Demand Forecast methodology.

Lastly, probabilistic simulations are performed to produce the final peak demand forecast of non-coincident bus peaks. For the System Peak Demand Forecast, Toronto Hydro modeled the variability of temperature to consider the impact of climate change on econometric indicators and simultaneously included drivers for data centers, electric vehicles, conservation and demand management, and distributed energy resources forecasts and applied a probability to determine the most likely outcome.

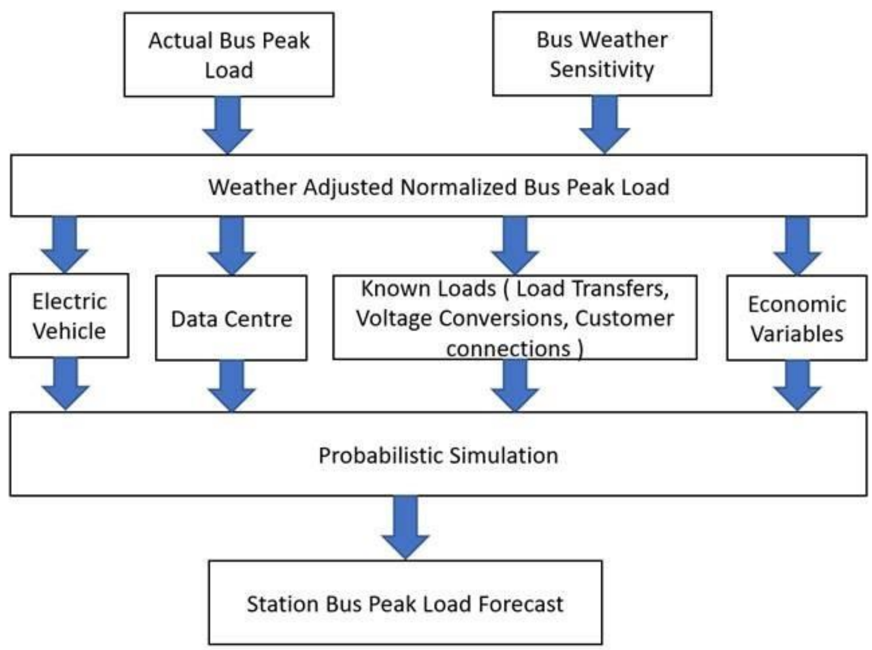


Figure 5: Process to Forecast Peak Demand at Substations

Recognizing the unprecedented energy transition set to unfold over the coming years, Toronto Hydro augmented its capacity planning and decision-making process with the results of long-term scenario modelling tool known as Future Energy Scenarios. The Future Energy Scenarios model is distinct from the Peak Demand Forecast in that it does not attempt to determine the most likely demand based on historical trends and other probabilistic sources of information. Rather, 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.[41]

[41] Future Energy Scenarios model is described in more detail in Exhibit 2B, Section D4, Appendix A and Appendix B.

2. Connection Capability

In order to connect new customers, both capacity and spare feeder positions are needed. As existing feeders reach their capacity, new feeders must be pulled from a station into the distribution system to connect new customers. Although a station may have the capacity to supply this demand, if there are no feeder positions to connect new feeders to the station, then the station would be unable to support new connections. To this end, Toronto Hydro also monitors the number of spare feeder positions at its stations. When new feeders are needed and no spare feeder positions are available, Toronto Hydro engages in capital work under the Load Demand program to transfer feeder loads and free up feeder positions so that new customer connections can be made.[42]

D3.3.1.2 Generation Capacity & Capability Assessment

Increased demand for power from consumers and the interconnection of distributed energy resources ("DER") have placed limitations on certain areas of the system. Toronto Hydro supports connecting DERs to the distribution system in alignment with the Distribution System Code and in coordination with Hydro One Networks and the IESO. Toronto Hydro has identified a number of constraints within its system that impact DER connections and interconnection-related decisions, including the following:

1) Short circuit capacity constraints;
2) Anti-islanding conditions for DER;
3) System thermal limits and load transfer capability; and
4) Protection and power quality challenges from high DER penetration.

To determine the impact of DER penetration on a station feeder, sophisticated fault and power flow simulation models are employed. These models provide visibility on different variables, such as fault current, and the contribution of those variables to the limiting constraints listed above.

Studies are performed for each new DER application enabling Toronto Hydro to continually evaluate the available existing short circuit capacity of the system.

[42] Exhibit 2B, Section E5.3.

D3.3.2 Capacity Risk Mitigation Methods

Based on the risk assessments above, Toronto Hydro invests in a number of programs to mitigate the risk of capacity shortfalls or the inability to connect new customers. These methods include expansion to increase capacity, enhancements to better utilize existing equipment, and load transfers as detailed below.

D3.3.2.1 Expansion Investments

Expansion investments provide one approach to manage the risk of capacity shortfalls within the system. By increasing capacity at substations, Toronto Hydro is able to address the need in localized areas of the system that experience load growth. Investments for expansion are primarily funded through the Stations Expansion program.[43] Expansion investments often require involvement from the transmitter, and Toronto Hydro may need to provide capital contributions for upgrades to transmission equipment at substations to enable an increase in capacity. Expansion may also be embedded as part of renewal activities for power transformers and switchgear units if deemed necessary, either to increase capacity or to increase the number of feeder positions available at a substation to provide new feeders to connect customers.

D3.3.2.2 Load Transfers

Prior to investing in expansion projects, Toronto Hydro assesses the feasibility to alleviate capacity shortfalls by transferring load to adjacent feeders, buses, or substations. If feasible, transfers are typically more cost effective than expansion. This approach allows Toronto Hydro to ensure efficient utilization of its existing infrastructure prior to investments in expansion.

D3.3.2.3 Enhancement Investments

Toronto Hydro also considers investments that allows it to enhance the system in order to alleviate capacity shortfalls or connection limitations, in a cost-effective manner. To manage load restrictions, especially due to peaks, Toronto Hydro has worked extensively with its customers to implement a Local Demand Response program to manage peak demand effectively and developed an Energy Storage Systems program.[44] For generation connections, investments in monitoring and control equipment are made through capital programs, including Generation Protection, Monitoring, and

[43] Exhibit 2B, Section E7.4.
[44] *Supra* note 15.

Control, to actively manage DER sources to ensure safe connections.[45] These investments allow Toronto Hydro to effectively manage capacity and connection limitations, without the need for extensive renewal activities, thereby deferring large capital investments. These investments form part of Toronto Hydro's Grid Modernization Strategy for 2025-2029.[46]

D3.4 Program Planning Approach and Project Development

This section details the framework and process that Toronto Hydro relies on to develop its capital and maintenance programs. It highlights the key components of the IPPR process that drives the development of investment programs, as shown in Figure 6.

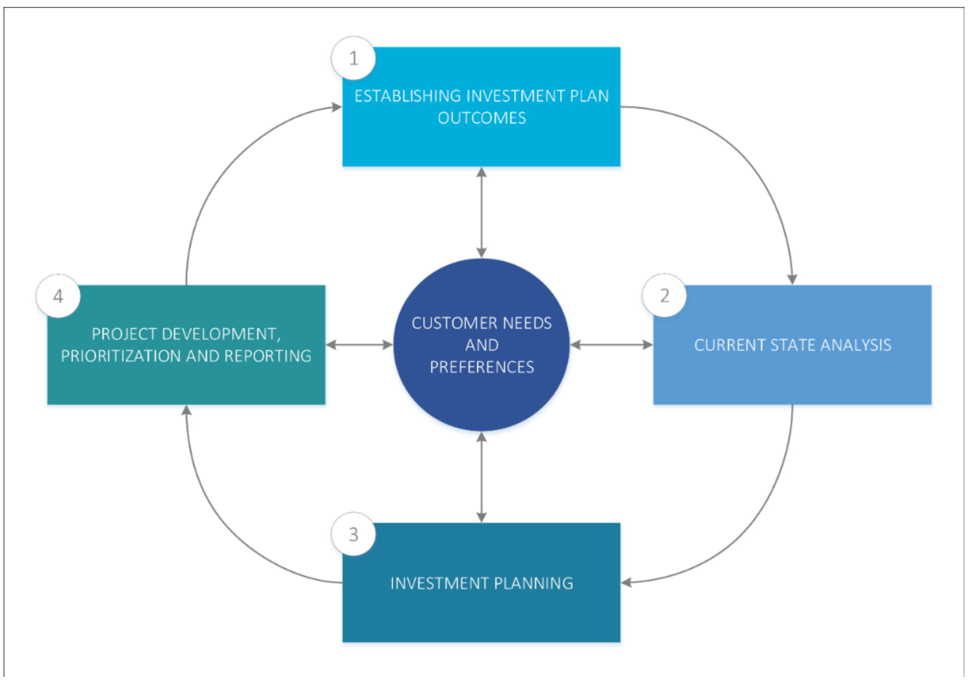


Figure 6: The IPPR Program Development Framework

The process can be divided into four key components:

1) **Asset Management Policy, Goals, and Objectives:** The process begins by establishing the asset management policy, goals, and objectives, and is informed by both the broader corporate strategy as well as customer needs, expectations, and feedback.

[45] Exhibit 2B, Section E5.5.
[46] Exhibit 2B, Section D5.

2) **Asset Needs Assessment:** This part of the process establishes an understanding of the current state of assets based on asset demographics and condition results. This information provides the base data required for planners to analyze the risk that the asset poses to the system.
3) **Portfolio Planning:** Based on the information output from the first two steps and the various risks discussed above, Toronto Hydro analyzes assets to identify the required level of spend to manage risk and in turn achieve the intended outcomes. Based on the driver of the work, investment programs are established as part of this step.
4) **Portfolio Reporting:** Once investment programs have been executed in the field through individual projects, the IPPR process includes a feedback loop where the project-specific execution status and project expenditures are reported to inform projects proposed in upcoming years.

D3.4.1 Asset Management Policy, Goals and Objectives

As discussed in Section D1, Toronto Hydro's Asset Management System ("AMS") is guided by its AM policy, goals, and related outcome objectives that the utility sets in alignment with its corporate pillars, objectives, and customer engagements. Figure 4 in Section D1 provides a summary of the AM policy, goals, and objectives, and Section E2 provides an overview of how Toronto Hydro established its AM outcome objectives for the 2025-2029 DSP.

Toronto Hydro uses outcome measures in each focus area to quantify the impact of investments towards each outcome. This framework is integral in enabling decision-making for asset management in both the long-term and short-term. For more details on Toronto Hydro's proposed Performance Measures for the 2025-2029 period, see Exhibit 1B, Tab 3, Schedule 1.

D3.4.2 Asset Needs Assessment

In order to create an optimized program, Toronto Hydro completes a needs assessment. In this regard, an important process is the current state analysis ("CSA") which provides Toronto Hydro with an assessment of the major assets that are currently installed in the system.

Key parameters that are collected from and integrated into the CSA include:

- Asset registry data (e.g. nomenclature, asset class/sub-class, installation type);
- Asset quantity data;

- Asset condition assessment and demographic data; and
- Asset-class and system-wide replacement value based upon useful life criteria.

The CSA utilizes information from Toronto Hydro's various enterprise systems, including the Geographic Information System ("GIS") and Enterprise Resource Planning ("ERP") system to establish the core asset registry data and asset demographics. Through the development of the CSA, Toronto Hydro can quickly establish key information on major assets including condition, age, useful life, and replacement value.

There are two key outputs from the CSA process:

- **Asset demographic data:** Provides a yearly break down for the number of asset units installed along with their respective costs. This data set allows Toronto Hydro to establish the percentage of assets past useful life.
- **Condition demographic data:** Indicates Health Scores (and subsequent Health Index bands) for applicable asset classes and sub-classes, helping to flag higher risk assets within the system from a condition perspective.

This process establishes foundational data that is used in the long-term and short-term planning processes for distribution assets. Figure 7 illustrates the inputs, elements, and outputs associated with the CSA.

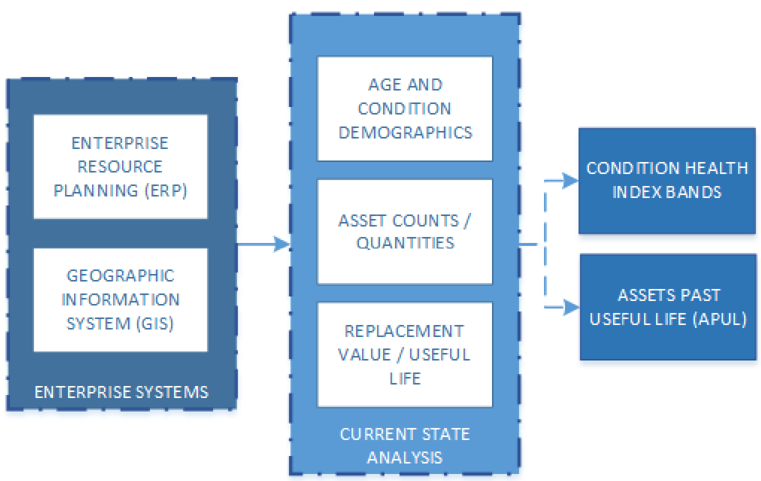


Figure 7: CSA Process

In addition to asset specific data, Toronto Hydro assesses emerging needs and challenges of the system by evaluating additional risk factors. For example, Toronto Hydro evaluates the available and forecasted capacity of the system to identify capacity-related risks. As discussed in Section D1.2.1.2 as well as D3.3 above, this is done through load forecasting, reviewing scenarios such as the Future Energy Scenarios ("FES"), load and generation connections forecasting, as well as the Regional Planning Process. These processes enable Toronto Hydro to identify spare capacity and anticipate areas of potential constraints as a result of developments and load growth or reductions in different areas of the City. The Regional Planning Process is an important input for distribution system planning (specifically, station plans), as a result of infrastructure planning on a regional basis to better predict system challenges. Capacity Planning is discussed in more detail in Exhibit 2B, Section D4.

Toronto Hydro accounts for emerging needs as they arise in the system. This could be as a result of asset specific information (legacy assets and configurations, safety and environmental concerns relating to a specific type of asset), climate and weather impacts, technological advances, or available capacity to connect customers. The processes identified in this section are used to assist system planners with developing well informed plans that consider the various risks and challenges mentioned above in order to meet the needs of the system.

The results of the Asset Needs Assessment that formed the basis of Toronto Hydro's system investment plan for 2025-2029 are discussed in Exhibit 2B, Section E2.2.

D3.4.3 Portfolio Planning

The Portfolio Planning process produces program-level expenditure plans in alignment with the utility's asset management objectives. As part of Portfolio Planning, asset-related data from the CSA is combined with system-wide information regarding known challenges facing the distribution system in order to assess asset and system needs. Toronto Hydro relies on the analyses and decision support tools (as discussed in Section D3.2 and Section D3.3) to identify assets or areas with high levels of risk requiring intervention. When identifying and proposing portfolios, the utility also accounts for customer feedback resulting from regular customer engagement activities. Customers' needs and preferences are a key input for determining the investments needed to meet customers' expectations on service.

During the Portfolio Planning process, Toronto Hydro develops investment requirements for managing system assets and challenges, based on the condition of assets, age of assets, risks of asset failure, legacy assets within the system, load growth, and opportunities for modernization. The analysis of assets from both a risk and outcomes perspective during the investment planning process ultimately drives the development (and management) of capital programs, which are detailed in Exhibit 2B, Sections E5 to E7 of the DSP.

The various risk analyses presented in Section D3.2 and Section D3.3 drive the overall investment required to manage the distribution system. Toronto Hydro assesses its entire asset base in light of the risks discussed above. Assets that are past their useful life or in HI4 ("material deterioration") or HI5 ("end of serviceable life") condition are identified, as defined earlier in Section D2.2. Information regarding historical failures is combined with asset level information to better understand not just the probability of failure but the cause of failure as well. The configuration of the system is also analyzed in these cases to see if inherent design limitations are contributing to increased risk for specific assets or types of configurations in the system. For example, the presence of legacy assets, such as paper-insulated lead-covered ("PILC") cable and asbestos-insulated lead-covered ("AILC") cable, can often result in safety or environmental consequences. The severity of the risk posed by these assets is considered when deciding whether to invest in replacing these assets proactively and also in determining the correct pace of replacement. Ultimately, similar types of interventions with the same driver are aggregated into capital programs. The expected probability of failure and historical reliability information also drives the requirement for Reactive and Corrective capital in order to address the level of failures observed.

In addition, Toronto Hydro must consider work that must be accomplished as part of its mandate (e.g. pursuant to the Distribution System Code), and responsibility as a Local Distribution Company ("LDC"). These investments may be demand driven or initiated by a third-party, and are categorized as System Access programs, such as Customer Connections or Externally Initiated Plant Relocations.

Program expenditures are then aggregated to create a total investment plan for any given year. The impact of the cumulative investment plan on outcomes is considered to ensure that investments are made in a prudent manner that manages the various risks discussed in this section while providing value for the customer.

Toronto Hydro considers, on an aggregate level, the impact of various investment levels on outcome measures (for example, SAIFI, SAIDI, and System Capacity). By forecasting the performance of key outcome measures over the long-term under proposed investment levels, Toronto Hydro is able to understand trade-offs in investing in different programs and at different investment levels. This initial investment requirement represents a bottom-up needs assessment by system planners for the optimal expenditure levels required.

Various investment strategies are reviewed and deliberated internally before selecting a proposed approach. Once investment plans are reviewed, the information becomes a foundational input as part of other corporate business planning activities.

For more details on how these activities unfolded for the 2025-2029 Capital Expenditure Plan, see Exhibit 2B, Section E2.

D3.4.4 Portfolio Reporting

The IPPR process also creates a feedback loop that provides information about program level completion and historical work executed in each program.

Information is reported on an individual project basis and includes the project's total spending and assets replaced or installed in any particular program. This data is broadly used within Toronto Hydro in assessing the status of capital programs as a result of the completed projects. This was first outlined in Section D1.2.1.3 under the discussions regarding the IPPR process. The aggregate of project-specific expenditures and asset units installed indicates how much of the capital investment program has been executed relative to the target for the program. Reporting is an important component in the process as it provides feedback on Toronto Hydro's ability to execute proposed investments as well as an opportunity to revisit and adjust plans for the upcoming years if needed.

D3.4.5 Project Development and Prioritization

As part of short-term planning activities, once capital investment programs are established, as explained in Section D3.4.3, assets and issues identified for each program are addressed as part of discrete capital projects. As explained within Section D1.2.2, the scope and project development process includes four phases: (i) identification of specific needs; (ii) assessment of options; (iii) high level scope creation; and (iv) refinement of scope and cost estimation.

During the first two phases, investment planners analyze discrete portions of the distribution system, such as a neighbourhood or street, in order to identify projects that align with the investment program criteria and drivers. Depending on the investment program driver and program type (i.e. core renewal, critical issues, or other necessary day-to-day operational investments), enterprise data is used to identify assets at a discrete level so that investment opportunities are identified, risk is managed, and outcome objectives are achieved. For example, with respect to a program driven by failure risk, enterprise systems and the analyses discussed in Section D3.2 can be utilized to identify the program-level prioritized assets that align with this driver.

In addition, ACA results can be used to identify those assets in HI4 and HI5 bands. Reliability analytics can be used to cross-reference studied locations against historical reliability events and performance issues. Finally, enterprise systems including the GIS are used to further support the study process, by providing supplementary details such as age, asset type and sub-type information.

For safety or capacity constraint-driven programs, nameplate information or localized data (as per the load forecasting process, discussed in Section D3.3) may be used to identify specific investment needs.

When an investment need for a project within a particular investment program has been confirmed and verified, phase three of the Scope and Project Development is carried out. A project draft, also known as scope of work, is produced which confirms the assets to be replaced, and establishes the high-level design for the new assets to be installed. While some projects may involve assets replaced in-kind, other projects may result in the installation of new assets in a new configuration. Examples include the conversion of overhead plant rear lot to underground plant in order to minimize outages caused by external factors, or the re-configuration of radial circuits to looped circuits and redistribution of load in order to reduce outage duration and impacts. Ultimately, the high-level forecasts produced via the long-term planning process will be further refined into an annual capital budget, as more rigorous project estimates are produced.

In tandem with producing the high-level design, Toronto Hydro documents the scope of work to be performed and produces a high-level cost estimate to execute the project. Efficiency savings can be realized by addressing the prioritized assets and issues along with adjacent assets that also require intervention as a single project, as opposed to replacing these assets individually on a reactive basis. Toronto Hydro is undertaking a multi-year project to implement its EAIP system. Projection information will be stored within this system, along with key supporting data points and impacted assets, to enable value calculations by applying Toronto Hydro's custom Value Framework. A project study may also be divided into multiple project drafts where necessary to allow construction to be executed in manageable pieces that are minimally intrusive to both the general public as well as customers. As part of the project development process, Toronto Hydro also considers issues such as city road moratoriums, physical restrictions, or particular design related problems that may delay the project or require a redesign. The project draft then undergoes a quality control assessment, before proceeding into the project finalization stage through the planning supervisor.

Once approved, the project is further refined both in terms of the scope of work as well as the cost estimate. As part of this process, field visits are conducted to ensure accuracy of the data that is used, obtain additional information and measurements, and to understand other potential risks for construction. Permitting requirements are also dealt with at this stage. This process results in a more refined project draft and cost estimate.

Ultimately, a series of projects are produced for each investment program, which results in further refinement to the capital investment spending levels for the associated program. Once the projects are finalized, they will be scheduled for execution based upon the Project Management and Execution process outlined in D1.2.3. Each project is scheduled based upon relative priority, resource availability, and system constraints (e.g. contingency issues or summer switching restrictions). Factors that impact project scheduling and execution include:

- Project scope and requirements, for example, asset delivery to locations and complexity of the site;
- External constraints such as coordination with external groups;
- Permitting and moratoriums;
- Supply chain;
- Coordination between other projects; and
- Resource balancing.

As part of scheduling, investment planners and program managers meet to discuss the relative priority of the various projects to establish the capital work program for execution in a given year. Toronto Hydro is currently on track to begin leveraging the optimization capabilities of its EAIP tool for the vast majority of its investment programs by the beginning of the 2025-2029 period. The implementation of EAIP will allow Toronto Hydro to implement and adopt a consistent and robust measure of value (and risk) for improved asset management decision making.

As part of the execution process, the detailed project design and estimate are produced to finalize capital investment spending levels. To address any required change to the project cost, schedule, or scope of work, Toronto Hydro maintains a change management and governance process. This process provides visibility across all relevant stakeholders on major project changes, requiring approval so that the change is appropriately processed and documented for awareness regarding lessons learned for future projects.

Asset Condition Assessment

Methodology Update and 2022 Results Analysis

1. Introduction

Asset Condition Assessment ("ACA") involves the use of condition inspection data to estimate the remaining serviceable life of physical assets. Utilities periodically inspect physical assets to monitor signs of degradation (e.g. visible corrosion) that can lead to asset failure. Inspection data on its own is useful in identifying and prioritizing assets for maintenance, refurbishment, or replacement. An ACA augments inspection data for assets by processing such data to arrive at a health score that represents an asset's condition and proximity to end of serviceable life.

This report highlights changes to Toronto Hydro's approach to ACA since implementing the Condition Based Risk Management framework ("CBRM") in 2017[1] and summarizes the ACA results for 2022 year-end ("YE"), including projections to 2029YE.[2] For convenience, the 2017YE results are also produced. Section 2 summarizes the key changes Toronto Hydro implemented to its ACA methodology, including continuous improvement efforts to implement additional components of the CBRM.

Section 3 highlights the ACA results for 2017YE, 2022YE, and projections for 2029YE, which are also summarized in Exhibit 2B, Section D3, Appendix B. Planners use inspection data and individual HI scores – in combination with other information and professional judgement – to prioritize assets for tactical intervention in the short- to medium-term. This includes identifying priority deficiencies that require reactive or corrective action and prioritizing assets for planned renewal projects in a given budget period. At a strategic level, Toronto Hydro uses ACA results to examine condition demographics and trends within major asset classes. ACA results (i.e. Health Scores) for a particular asset class are grouped into five Health Index ("HI") bands that represent key stages of an asset's lifecycle, ranging from new or like-new condition to the stage where asset degradation is significant enough to warrant urgent attention. This information supports the development of longer-term investment plans and serves as an important input into Toronto Hydro's 2025-2029 DSP. For more details on how Toronto Hydro leverages ACA within its Asset Management framework, please refer to Section D3.

2. Summary of Enhancement to ACA Methodology

Within CBRM there are three main aspects: Asset Health, Asset Criticality, and Asset Risk, with the latter being a combination of the first two. Each of these can be expressed as an index, which indicates relative value, or a specific value (probability or monetary). As part of its initial implementation in 2017, Toronto Hydro focussed on Asset Health expressed through the Health Index, which fully replaced and improved upon its previous asset health methodology. Since then, Toronto Hydro continues to review and refine the existing methodology, as well as build on it by adopting incremental components of CBRM, including condition-driven Probability of Failure ("PoF") on the Asset Health side and Consequence of Failure ("CoF") on the Asset Criticality side. Toronto Hydro retained EA Technology to help guide this process and to review the improvements as well as identify opportunities for continuous improvement. EA

[1] See EB-2018-0165, Exhibit 2B, Section D, Appendix C for details.

[2] The specific implementation of CBRM used by Ofgem for regulatory purposes is called the Common Network Asset Indices Methodology, or "CNAIM".

Technology's review of Toronto Hydro's current ACA models and results is included in Exhibit 2B, Section D3, Appendix C.

Table 1 below summarizes the material refinements introduced to the Asset Condition Assessment Methodology.

Table 1: Material Refinements to ACA Asset Models

Refinement	Description	Impacted Asset Models
Normal Expected Life	Toronto Hydro implemented changes to the normal expected life within the ACA models of impacted asset classes to reflect revisions to useful life values in light of its updated Depreciation Study completed by Concentric Inc.[3]	• Underground Transformer (Submersible, Padmount, & Vault) • Air Insulated Pad-mount Switches • Network Protectors • SCADAMATE switches • Circuit Breaker (Air Blast, Air Magnetic) • Station Power Transformer
Wood Pole Asset Model Refinement	The condition factor for the Wood Pole model was refined based on Toronto Hydro's field experience to better reflect specific condition parameters. Specifically, the level of granularity was increased within the models for the following condition parameters: Pole Base Rot was separated into: • Pole Base Rot (At/Below Ground Level) • Pole Base Rot (Above/ Level) Pole Void was separated into: • Pole Void (Wood Loss) • Pole Void (Hollow Heart/Pockets Present) Bird/Animal Damage: • Calibrated factor for "Extensive" condition observation Pole Separation was separated into: • Pole Separation (Cracks) • Pole Separation (Pole Top Feathering)	• Wood Pole

[3] Available at Exhibit 2A, Tab 2, Schedule 1, Appendix D. While the Depreciation Study was intended primarily to determine useful lives for financial purposes, Toronto Hydro leveraged insights gained from that exercise to review and revise as appropriate its 'engineering' or 'planning' useful lives.

Continuous Improvement:

In addition to the refinements and enhancements above, Toronto Hydro is in the process of implementing condition-driven PoF curves for applicable asset classes. For a given asset, the PoF per annum can be calculated with the following cubic relationship:

$$PoF = k \cdot \left(1 + (H \cdot C) + \frac{(H \cdot C)^2}{2!} + \frac{(H \cdot C)^3}{3!}\right)$$

Where:

- k, C – Asset class specific constants
- H **–** Asset health score unless $H \geq 4$, 4 otherwise

Historical failure data in conjunction with the calculated health scores are used to determine PoF parameters on an asset class basis.

In addition to the PoF, Toronto Hydro intends to implement the Consequence of Failure ("CoF") and Criticality aspects of CBRM, co-ordinating and aligning with Value Framework developments for System Renewal investments as part of its implementation of an Asset Investment Planning ("EAIP") system. For details on Toronto Hydro's Value Framework developments, please see Section D1.2.1.1 and D3.2.1.1.

3. Health Score Results

Tables 3-5 and Figures 1-3 provide a summary of the health index distribution for each asset class by count and percentage:

- Historical, as of the end of 2017;
- Current, as of the end of 2022
- Future, projected for year end 2029

The health bands are defined as per table 2 below:

Table 2: Health Index bands and definitions

HI Band	Lower Limit of Health Score	Upper Limit of Health Score	Definition
HI1	≥ 0.5	< 4	New or good condition
HI2	≥ 4	< 5.5	Minor deterioration; in serviceable condition
HI3	≥ 5.5	< 6.5	Moderate deterioration; requires assessment and monitoring
HI4	≥ 6.5	< 8	Material deterioration; consider intervention
HI5 (Current Health)	≥ 8	≤ 10	End of serviceable life; intervention required
HI5 (Future Health)	≥ 8	≤ 15	

Table 3: Summary of Health Index Distribution as of year end 2017.

Asset Class	Health Score				
	HI1	HI2	HI3	HI4	HI5
Cable Chambers	8,112	1,162	1,350	398	89
4kV Oil Circuit Breaker	36	4	123	24	
AirBlast Circuit Breaker	15	9	206	1	3
Air Magnetic Circuit Breaker	145	90	247	21	53
Oil KSO Circuit Breaker	10	7	11	11	1
SF6 Circuit Breaker	130	6	18	3	3
Vacuum Circuit Breaker	578	46	13	2	29
Network Protectors	1,086	185	319	74	26
Overhead Gang operated Switches	854	27	76	3	9
Air Insulated Padmount Switch	404	20	73	30	45
SF6 Insulated Padmount Switch	402	-	2	-	6
SCADAMATE Switches	1,084	1	26	-	8
Air Insulated Submersible Switch	755	79	27	7	-
SF6 Insulated Submersible Switch	353	14	7	3	19
Station Power Transformers	83	77	61	13	8
Network Transformers	1,334	255	166	60	7
Padmount Transformers	5,547	656	283	113	18
Submersible Transformers	7,816	588	271	172	55
Vault Transformers	6,807	4,315	450	214	45
Underground Vaults (Combined)	1,017	186	72	12	29
ATS Vaults	8	-	-	-	-
CLD Vaults	21	-	-	-	-
CRD Vaults	9	-	1	-	-
Network Vaults	322	120	63	11	29
Submersible Switch Vaults	115	5	-	-	-
URD Vaults	542	61	8	1	-
Wood Poles*	63,526	7,354	29,779	5,687	722

*Please note that Wood Pole results are re-calculated based on the refinement to the Wood Pole asset model highlighted in Table 1 above.

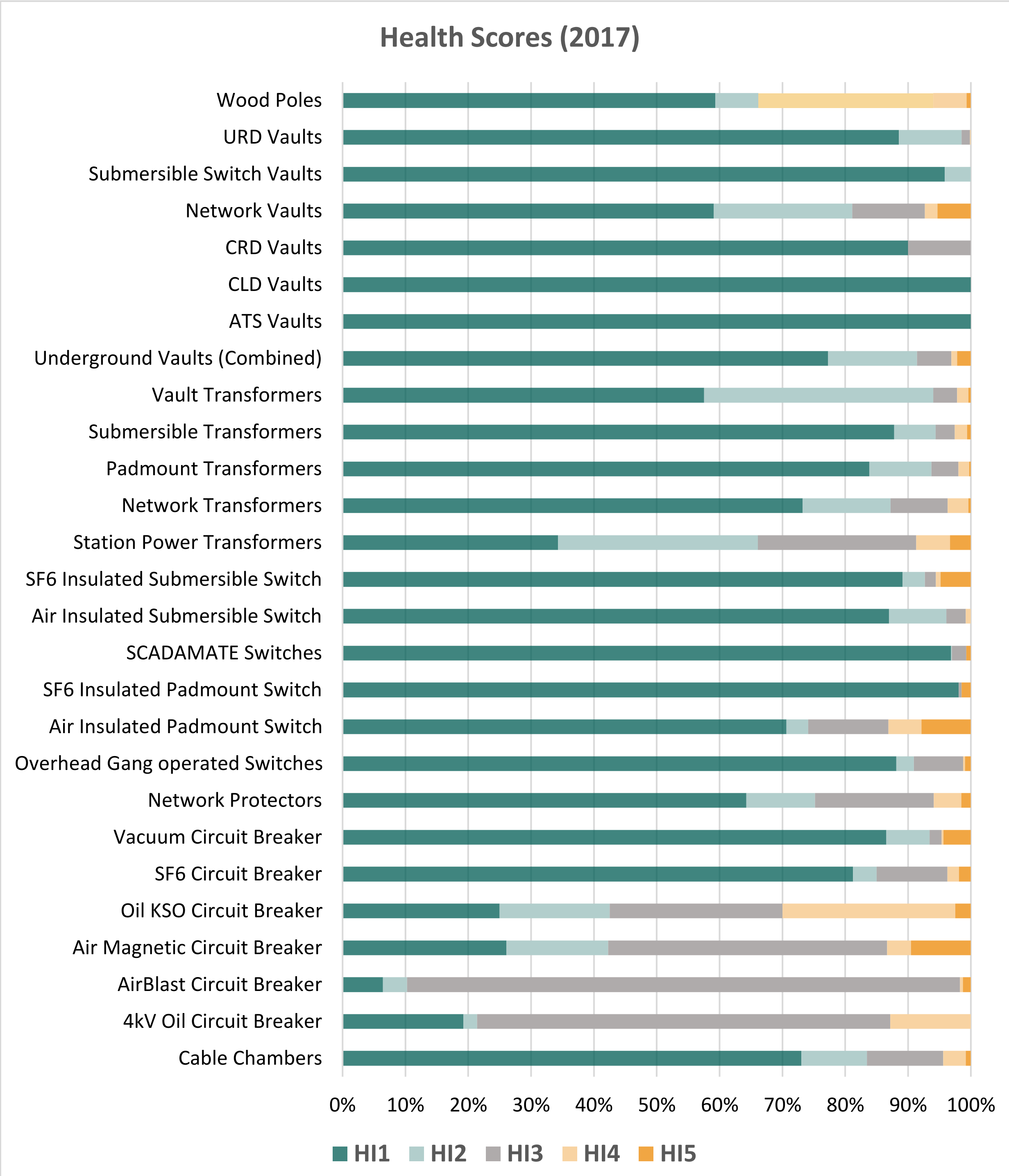
Table 4: Summary of Current Health Index Distribution as of year end 2022.

Asset Class	Health Score				
	HI1	HI2	HI3	HI4	HI5
Cable Chambers	6,640	1,346	2,079	462	130
4kV Oil Circuit Breaker	4	-	53	-	1
AirBlast Circuit Breaker	2	1	137	8	8
Air Magnetic Circuit Breaker	61	47	357	2	27
Oil KSO Circuit Breaker	1	13	9	-	-
SF6 Circuit Breaker	121	6	2	4	-
Vacuum Circuit Breaker	803	12	10	-	-
Network Protectors	1,342	129	233	21	3
Overhead Gang operated Switches	659	98	88	10	13
Air Insulated Padmount Switch	359	4	64	24	29
SF6 Insulated Padmount Switch	663	-	-	1	16
SCADAMATE Switches	1,078	9	66	4	13
Air Insulated Submersible Switch	720	183	67	7	-
SF6 Insulated Submersible Switch	437	18	15	7	10
Station Power Transformers	87	66	12	8	-
Network Transformers	1,370	244	61	40	3
Padmount Transformers	5,142	1,085	527	233	24
Submersible Transformers	8,120	699	162	133	47
Vault Transformers	6,799	3,869	571	247	11
Underground Vaults (Combined)	870	164	49	53	47
ATS Vaults	5	1	-	1	-
CLD Vaults	20	2	-	-	-
CRD Vaults	8	3	-	-	-
Network Vaults	225	110	44	46	45
Submersible Switch Vaults	70	3	-	-	-
URD Vaults	542	45	5	6	2
Wood Poles*	68,288	7,566	21,073	8,950	509

Table 5: Summary of Future Health Index projected for year end 2029.

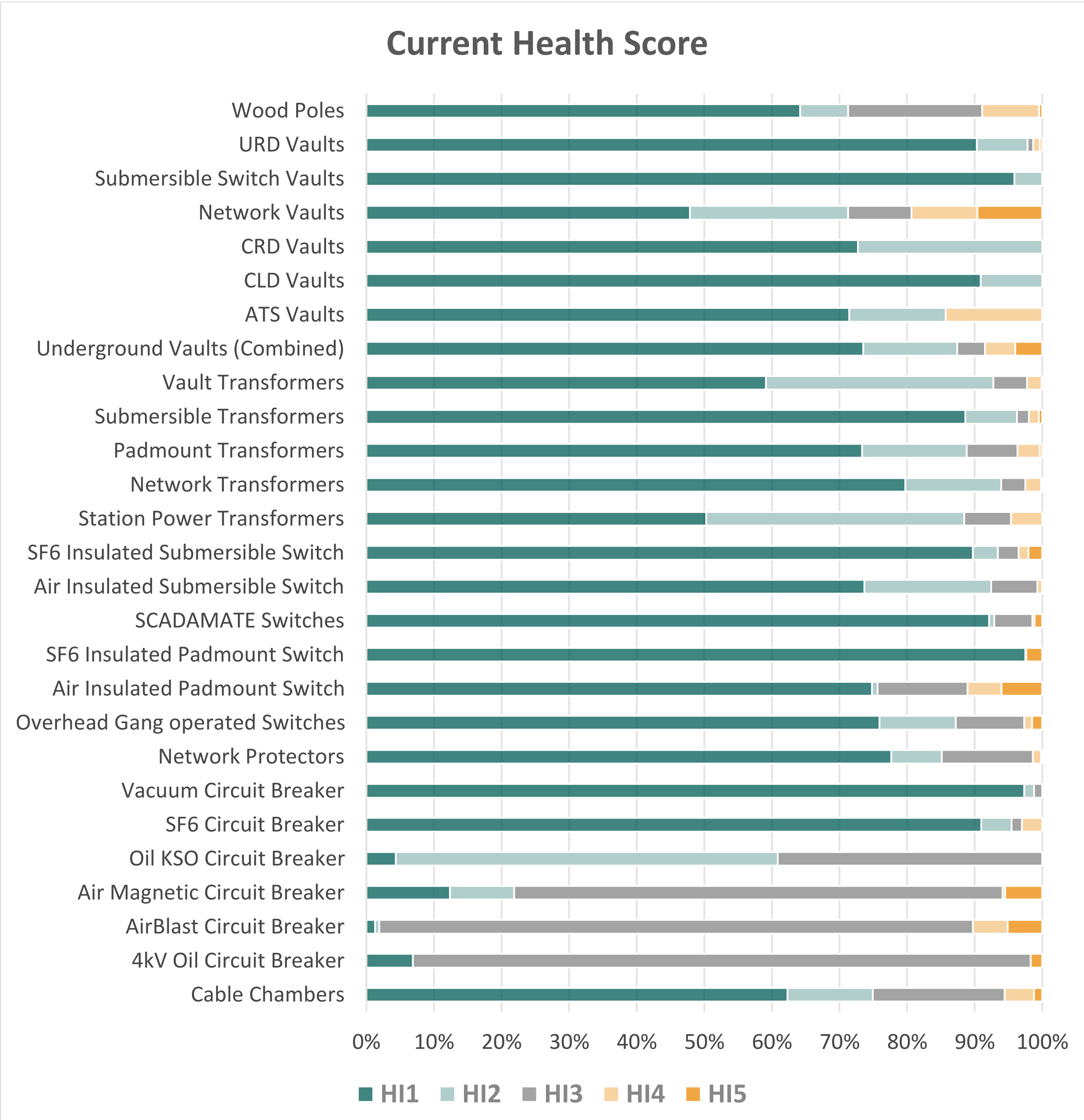
Asset Class	Health Score;				
	HI1	HI2	HI3	HI4	HI5
Cable Chambers	6,015	1,026	2,503	535	578
4kV Oil Circuit Breaker	4	-	29	24	1
AirBlast Circuit Breaker	2	-	97	43	14
Air Magnetic Circuit Breaker	11	50	41	361	31
Oil KSO Circuit Breaker	1	-	8	14	-
SF6 Circuit Breaker	93	28	4	2	6
Vacuum Circuit Breaker	786	17	10	12	-
Network Protectors	1,298	40	56	187	147
Overhead Gang operated Switches	517	106	111	91	43
Air Insulated Padmount Switch	320	18	13	16	113
SF6 Insulated Padmount Switch	663	-	-	-	17
SCADAMATE Switches	724	65	69	149	163
Air Insulated Submersible Switch	667	53	152	90	15
SF6 Insulated Submersible Switch	419	26	9	6	27
Station Power Transformers	82	11	60	12	8
Network Transformers	1,243	111	215	87	62
Padmount Transformers	4,451	542	887	595	536
Submersible Transformers	7,330	642	635	240	314
Vault Transformers	5,220	1,668	3,595	587	427
Underground Vaults (Combined)	848	101	83	52	99
ATS Vaults	4	1	1	-	1
CLD Vaults	20	-	2	-	-
CRD Vaults	8	3	-	-	-
Network Vaults	207	92	34	47	90
Submersible Switch Vaults	68	4	1	-	-
URD Vaults	541	1	45	5	8
Wood Poles*	60,308	8,350	5,570	24,464	7,694

Figure 1: Health Score Distribution by Asset Class as of year end 2017



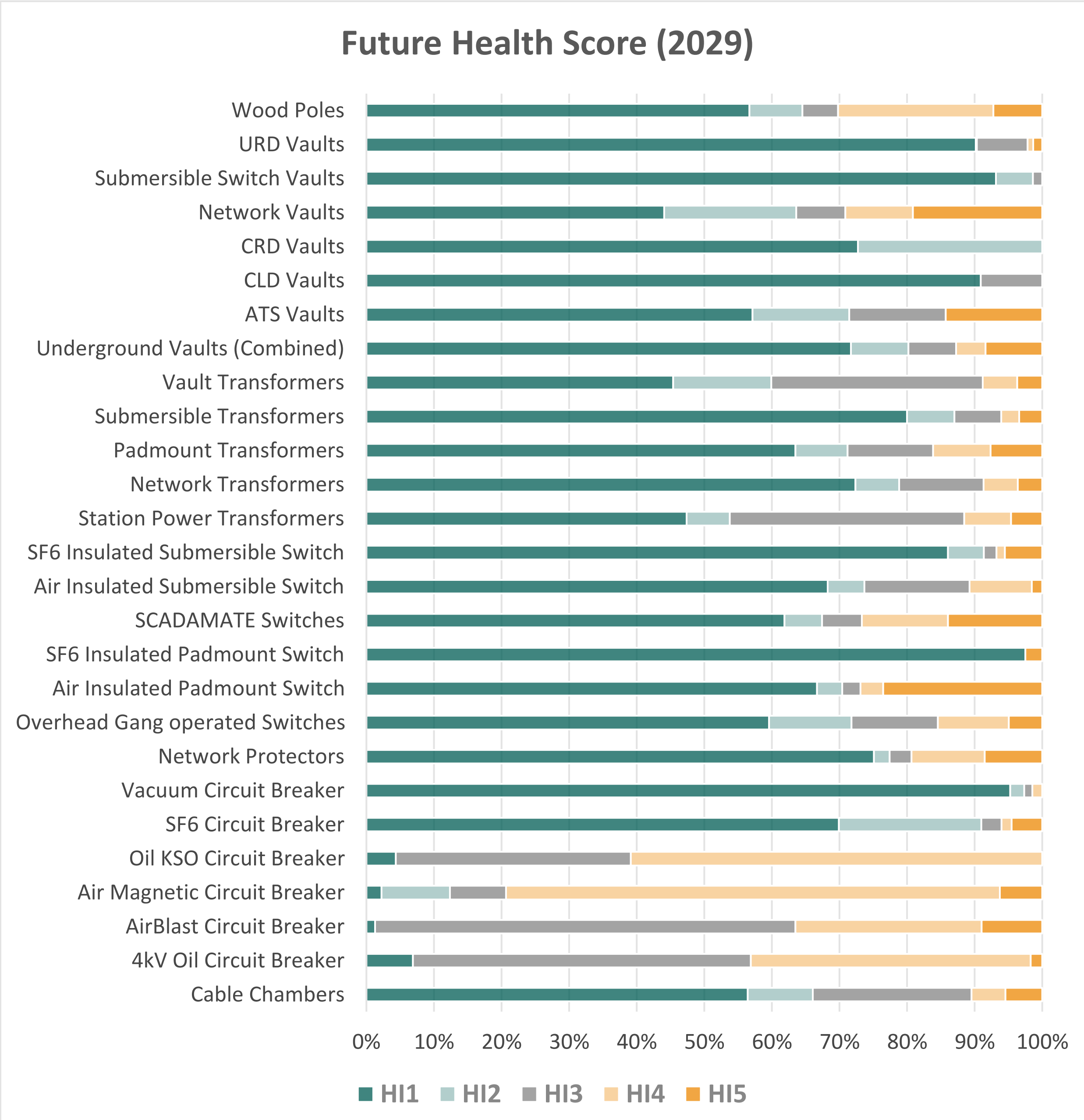
HI1 - New or good condition; HI2 - Minor deterioration, in serviceable condition; HI3 - Moderate deterioration, requires assessment and monitoring; HI4 - Material deterioration, consider intervention; HI5 - End of serviceable life, intervention required;

Figure 2: Current Health Score Distribution by Asset Class as of year end 2022

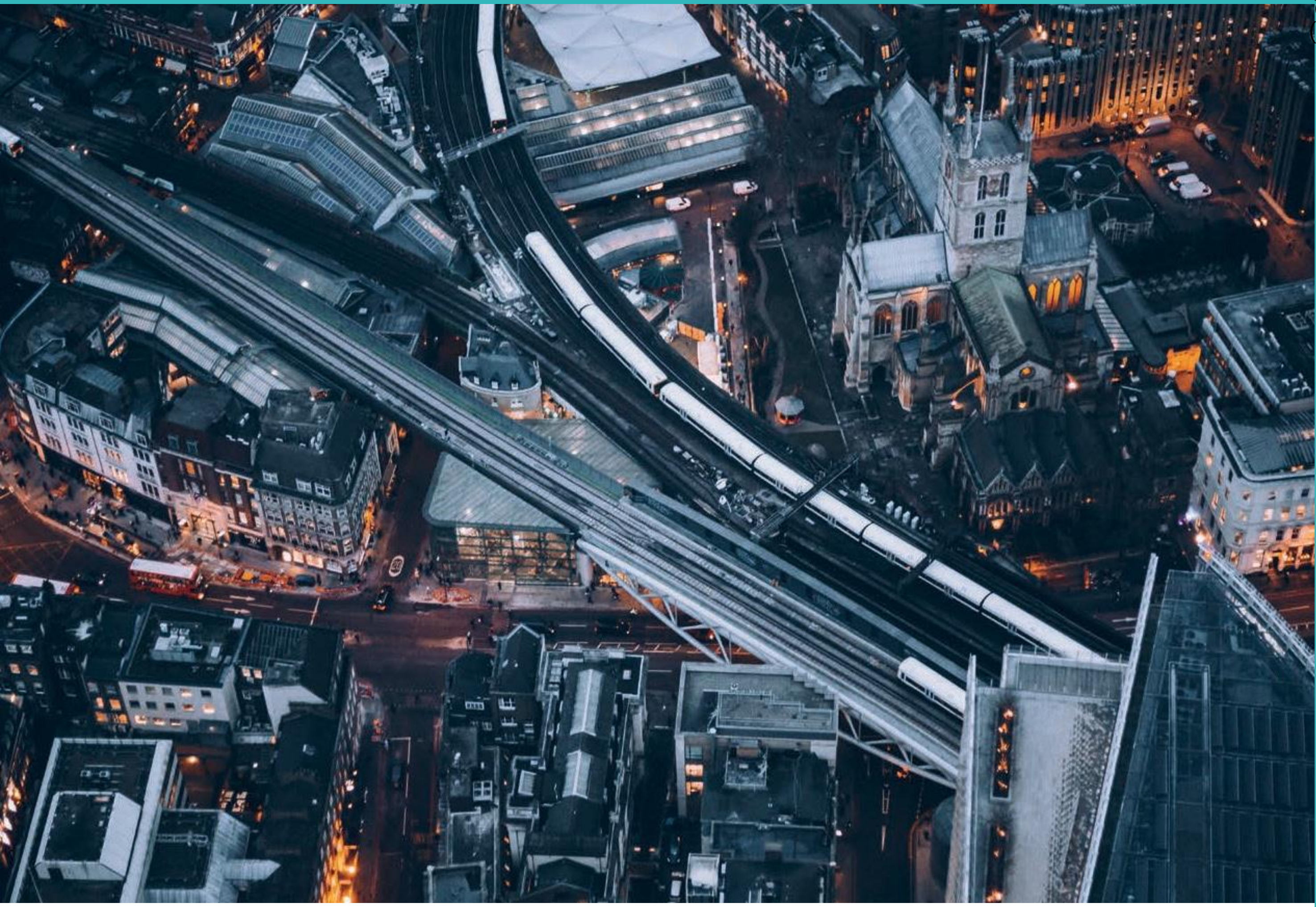


HI1 - New or good condition; HI2 - Minor deterioration, in serviceable condition; HI3 - Moderate deterioration, requires assessment and monitoring; HI4 - Material deterioration, consider intervention; HI5 - End of serviceable life, intervention required;

Figure 3: Future Health Score Distribution by Asset Class for year end 2029



HI1 - New or good condition; HI2 - Minor deterioration, in serviceable condition; HI3 - Moderate deterioration, requires assessment and monitoring; HI4 - Material deterioration, consider intervention; HI5 - End of serviceable life, intervention required;



REPORT

Review of ACA Modelling Enhancements and Customisations

Private and Confidential

Prepared for: Toronto Hydro-Electric System Ltd.

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03/07/2023	V1	Andrew Harrison, Tracy Pears	Draft for review by THESL
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Final Approval

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Contents

1. Introduction

Toronto Hydro-Electric System Limited (THESL), is a wholly owned subsidiary of Toronto Hydro Corporation, and is the largest municipal electricity company in Canada. Its electrical distribution network comprises of over 13,500km of underground cables and 15,000km of overhead lines that distribute around 19% of the electricity consumed in the province of Ontario to approximately 790,000 customers located within the city of Toronto and its surrounding area.

THESL is recognised within the region as a sustainable electricity company and is committed to develop its in-house capabilities through continuous improvement. Within the discipline of asset management, this has included an undertaking to implement a series of Asset Condition Assessment (ACA) models based on the Common Network Asset Indices Methodology (CNAIM).

CNAIM, or the Common Methodology as it is often referred to, is the approach used by Distribution Network Operators (DNOs) in Great Britain to report asset health and criticality as part of their regulatory reporting requirements. EA Technology has supported the GB Distribution Network Operators through the development of CNAIM and has worked with the majority of the GB DNOs to implement the methodology and embed it within their organisations.

In 2017/8, THESL, supported by EA Technology, successfully completed a project to develop, build and commission a suite of enhanced CNAIM-based ACA models to support their endeavours pertaining to the adoption of an advanced condition-based approach for electrical system planning, the strategic evaluation of both capital investments and day-to-day maintenance activities.

Since 2021 THESL has embarked on the process of enhancing its implementation of the ACA methodology, including implementation of probability of failure (PoF) and consequences of failure (CoF). EA Technology was engaged to provide guidance and feedback on the derivation of appropriate inputs to the PoF and CoF calculations.

This latest engagement involves an independent review of the ACA implementation, enhancements and customisations made by THESL since 2018. Consideration has been given to the general outputs of the enhanced THESL ACA models, alignment with the core principles of the CNAIM methodology, and the generally accepted industry practices for condition and risk-based asset management within an electrical distribution arena.

1.1 Scope and Objectives

The agreed scope of work to be undertaken by EA Technology comprises of three main activities:

- Task 1: a review of the changes and enhancements THESL has made to its health score methodologies since 2018.
- Task2: a review of the current and future health score outputs for three asset classes selected by THESL.
- Task 3: a review of THESL's implementation of probability of failure, consequence of failure, asset criticality and risk.

The objective of this undertaking is to provide assurance to THESL that the enhancements and customisations introduced into the ACA models since 2018 align with the core principles of the CNAIM methodology.

This piece of review work has been undertaken remotely and is limited to the materials supplied by THESL which, where necessary, have been supported by clarifications made via video conference meetings.

2. Definitions

The following terms and abbreviations are contained within this document:

ACA	Asset Condition Assessment
BOSCEM	Basic Oil Spill Cost Estimation Model
CAD	Canadian Dollar
CBRM	Condition Based Risk Management
CI	Customer Interruption
CMI	Customer Minutes of Interruption
CNAIM	Common Network Asset Indices Methodology
CoF	Consequence of Failure
DNO	Distribution Network Operator
GB	Great Britain
HI	Health Index
HS	Health Score
ITIS	Interruption Tracking Information System
kV	Kilovolt
PoF	Probability of Failure
PCB	Polychlorinated Biphenyl
SF_6	Sulphur Hexafluoride
THESL	Toronto Hydro-Electric System Ltd.
UG	Underground
WSIB	Workplace Safety and Insurance Board

3. THESL ACA Model Portfolio

Following completion of the initial ACA model development project in 2018, THESL currently operate and maintain a total of 21 asset condition assessment models. These models are listed in Table 1 below.

Table 1 Breakdown of THESL ACA models by Asset Type

Asset Type	THESL ACA Model / Asset Class
Switchgear	Air Insulated Pad-mounted Switches Air Insulated Submersible Switches Air Magnetic Circuit Breakers Air Blast Circuit Breakers Network Protectors Oil Circuit Breakers Oil KSO Circuit Breakers Overhead Gang Operated Switches SCADAMATE Switches SF_6 Circuit Breakers SF_6 Insulated Pad-mounted Switches SF_6 Insulated Submersible Switches Vacuum Circuit Breakers
Transformer	Network Transformers Pad-mount Transformers Station Power Transformers Submersible Transformers Vault Transformers
Overhead Line	Wood Poles
Civils	Cable Chambers UG Vaults

The initial ACA model development project was immediately followed by an independent review which was completed by specialist asset management consultants from EA Technology with expert asset condition modelling knowledge. This review recommended that changes to the ACA model calibration and its associated processes were made in order to disassociate the ACA model outputs from established THESL tactical asset management practice, which would allow the core CNAIM methodology to provide a more strategic view of the asset portfolio.

Following a short series of specialist asset management training sessions, and with the support provided by EA Technology, THESL successfully revised the calibrations such that the ACA models were less reliant upon computational caps and collars designed to ‘force’ health score calculations subject to the identification of user-specified asset deficiencies obtained through programmes of inspection. It is understood that the ACA models were internally reviewed by THESL to ensure real-world alignment before the models were ‘frozen’ prior to the start of preparations for the 2018/2019 regulatory filing.

4. ACA Asset Health Score Review

4.1 Introduction

Task 1 has involved a review of THESL's ACA model inputs and calibrations to identify any changes that have been made to the ACA Health Score derivation methodology since the models were previously frozen in 2018.

The review has considered:

- the full range of ACA models contained within Table 1 above;
- variation(s) in information sources, data validation, and input data fields which feed the ACA models' computational algorithms;
- changes to data processing approach, algorithm format, and calculation sequence;
- the process of ACA Health Score calibration employed by THESL;
- any revisions to calibration values (including condition caps and collars) and, where appropriate;
- THESL's rationale and justification for change.

4.2 Review of Findings

The independent desktop review has considered the information provided by THESL, from which it appears that THESL's asset management function remains comfortable with the vast majority of the previously frozen 2018 ACA models.

Information exchanged between THESL and EA Technology has confirmed that THESL have explored the possibilities for further ACA model development behind the scenes. Consideration has been given to potential solutions pertaining to geographic, situational and locational influences thought to directly affect asset health. However, difficulties have been experienced with a number of potential avenues explored in terms of data quality, availability, and ease of data maintenance. These issues are considered to affect the repeatability of ACA modelling over time, and therefore THESL have elected not to include this data enhancement until such time that a more enduring solution can be found. A summary table of ACA model modifications is provided in Table 2 below.

THESL have confirmed that there have been no notable changes in asset inspection and maintenance programmes since the last review, and that input data sourcing, processing and validation approaches remain unchanged since 2018, and therefore no changes to the number of model input data fields have been made.

Table 2 Summary of ACA Methodology Changes 2018 to Present

	Changes to ACA Model							
THESL ACA Model / Asset Class	Information Source?	Source Data Validation?	Model Input Data Fields?	Computational Algorithm Format?	Calculation Sequence?	Calibration Process?	Calibration Value?	Caps or Collars?
Air Insulated Pad-mounted Switches	No	No	No	No	No	No	No	No
Air Insulated Submersible Switches	No	No	No	No	No	No	No	No
Air Magnetic Circuit Breakers	No	No	No	No	No	No	No	No
Air-Blast Circuit Breakers	No	No	No	No	No	No	No	No
Cable Chambers	No	No	No	No	No	No	No	No
Network Protectors	No	No	No	No	No	No	No	No
Network Transformers	No	No	No	No	No	No	No	No
Oil Circuit Breakers	No	No	No	No	No	No	No	No
Oil KSO Circuit Breakers	No	No	No	No	No	No	No	No
Overhead Gang operated Switches	No	No	No	No	No	No	No	No
Pad-mounted Transformers	No	No	No	No	No	No	No	No
SCADAMATE Switches	No	No	No	No	No	No	No	No
SF_6 Circuit Breakers	No	No	No	No	No	No	No	No
SF_6 Insulated Pad-mounted Switches	No	No	No	No	No	No	No	No
SF_6 Insulated Submersible Switches	No	No	No	No	No	No	No	No
Station Power Transformers	No	No	No	No	No	No	No	No
Submersible Transformers	No	No	No	No	No	No	No	No
UG Vaults	No	No	No	No	No	No	No	No
Vacuum Circuit Breakers	No	No	No	No	No	No	No	No
Vault Transformers	No	No	No	No	No	No	No	No
Wood Poles	No	No	No	Yes	No	No	Yes	No

From a computational perspective, the high-level desktop review has found that modification to the THESL ACA Health Score methodology has only taken place within a single asset class, namely wood poles. For all other asset classes, the previously established input information sources, data validation techniques, computational algorithms and calculation sequences are understood to remain unchanged. THESL stand by the results produced by these models and have stated that their approach to ACA model verification, review and calibration continues to be directly aligned with earlier guidance and direction provided by EA Technology and continues to remain effective. Therefore modification of these ongoing ACA models and their associated maintenance processes has been deemed unnecessary.

Within the Wood Pole ACA model, the identified changes are considered to represent a significant indication of asset management maturity development and evidence of THESL's adoption and engagement with advanced asset management techniques. The modifications made to the wood pole ACA model are considered to be comparatively minor in nature, as they relate specifically to the observed condition point factor derivation. However, this act of refinement demonstrates the existence of functioning closed loop feedback channels within the organisation's asset management system, and proof that they are being effectively used.

Wood pole structures owned and operated by THESL are understood to be subject to a lengthy, 10 year inspection cycle, of which only a proportion of the asset population are condition assessed in any one year. This approach to asset inspection is commonplace as, if implemented correctly, the condition of other assets within the wider population can be either implied or inferred, reducing resource requirements and operational costs. However, this inspection approach also has a significance during ACA methodology and model development, as traditionally asset managers raise concerns about the ability of field data to accurately reflect the condition of physical assets which have not been inspected for a long period of time. Hence, the development of ACA models in such circumstances often takes place using only a proportion of the wood pole asset population and/or inspection information – which is neither unusual nor unexpected during asset modelling solution development.

Following the completion and commissioning of ACA models for asset classes with long inspection periods, over a period of time updated asset inspection data is collected, processed, and used to inform health score calculation. Gradually inference and implied condition are replaced with real condition data which enables the generation of more accurate asset health profiles.

ACA model outputs need to be subjected to regular review in order to reduce the risk of model drift – where the results produced by condition assessment modelling systems start to vary such that they gradually no longer accurately reflect the "real-world" physical asset condition. The key control to protect against drift being either re-calibration or model refinement.

As an organisation, THESL have acquired vital essential modelling experience with their updated ACA methodology and solution and are understood to have conducted a series of regular ACA model output reviews and tests. It is through this analysis that THESL have identified the early signs of conservative model drift, in which the health score profiles generated by the ACA system relating to wood poles are being recognised as being too pessimistic. i.e. are being represented by a higher health score than would be expected.

Evaluation of the ACA results has identified examples of field inspectors discovering multiple minor pole defects, small pole voids or low levels of pole rot at a wood pole structure being interpreted by ACA models as causing potential for an unacceptable increase in probability of failure, thereby directing intervention. THESL recognise such identified attributes as potential concerns; however, within the existing wood pole management framework, they would not provide a sufficient justification for significant capital intervention.

In part, this situation has been caused by inexperience and unfamiliarity pertaining to health score definition and interpretation and is likely to have been as a result of an overstatement of specific observed condition point influence during the model's initial development and calibration. The resulting effect being a natural misalignment of health score values during a period of bedding in and condition data refreshment.

EA Technology understand that the condition data input 'Pole Rot' was initially a combination of three data fields (Surface Rot Below Ground Level, Surface Rot at Ground Level, and Surface Rot Above Ground Level) collected during routine inspection. The data input into the ACA model was the worst of the recorded inspection results, with a commonly applied calibration. Following a review of the model outputs, THESL identified that the resultant condition factor was providing an excessive influence within the health score derivation. By separating these originally combined input data fields and using individual calibration tables, a higher degree of influence control can be obtained. THESL's ACA model refinement now treats the observed condition points 'Pole Base Rot (At/Below Ground Level)' and 'Pole Base Rot (Above Ground Level)' separately.

In the 2018 wood pole model, the observed condition points 'Pole Void' and 'Pole Separation' were treated in a similar way to 'Pole Rot'. The worst of two recorded inspection results formed the input into the ACA model, again, with a commonly applied calibration. Following the review of the results from the model outputs, THESL have separated the inputs as shown in Table 3 and included individual calibration tables to increase the modelling effect of moderate hollow hearts/pockets presence and reduce the modelled effect of pole structures found to possess slight cracks when compared to structures suffering with slight pole top feathering.

Table 3 Observed Condition Inputs for Pole Voids and Pole Separation in 2018 and 2022 Models

ACA Model 2018	ACA Model 2022
Pole Void	Pole Void (Wood Loss) Pole Void (Hollow Heart/Pockets Present)
Pole Separation	Pole Separation (Cracks) Pole Separation (Pole Top Feathering)

As part of the review process, the calibration associated with 'Extensive Animal damage' has also been revised (increased slightly) to align with the identified deficiencies outlined above.

In order to facilitate the changes outlined above, the computational data processing algorithms used to determine the Pole Rot, Pole Void and Pole Separation condition factors must have been modified to accept the additional data fields and calibration inputs. However, algorithms associated with the calculation of the Observed Condition Factor retain the standard MMI (Maximum and Modified Increment) technique used in CNAIM and is therefore considered to remain consistent with the underlying principles of the Common Methodology.

EA Technology consider that this type of ACA model refinement is only to be expected and would form part of the natural organic asset condition modelling process as organisations such as THESL adopt and embrace more modern, advanced asset management approaches. As in the case outlined above, any such model or methodology revision would be expected to include detailed internal evaluation, review and, where necessary, aspects of model re-calibration. Evidence of this having taken place exists in the fact that the observed condition factor 'Animal Damage' has been adjusted to ensure result consistency.

5. Review of Current and Future ACA Health Score Outputs

Task 2 has involved a desktop review of the ACA model outputs for the following asset classes as selected by THESL: Wood Poles, Network Transformers and Submersible Transformers. The data extract files have been provided in MS Excel format and include all data inputs, intermediate calculations (e.g. initial health score, condition modifiers, health score caps and collars), current health score values and predicted health scores for future years.

Observations on the implementation of the CNAIM methodology, the calibration settings and the current and future health index profiles for wood poles, network transformers and submersible transformers are provided in Sections 5.1 to 5.3. As part of the review, the intermediate calculations, including derivation of observed and measured condition modifiers and ageing rates have been verified as being consistent with the CNAIM methodology.

5.1 Wood Poles

The wood pole model comprises 106,386 assets ranging in age from new to more than 45 years old. The initial health score of each asset is derived from its age and the normal expected life of the asset class (45 years). More than 25% of the population (29,469 poles) have an initial health score of 5.5 driven by the age of the asset. This seems to be quite high and is likely to be due to the calibration of the Normal Expected Life (see Section 7.1).

The model includes both observed and measured condition modifiers as indicated in Table 4.

Table 4 Wood Pole Model: Observed and Measured Condition Modifiers

Observed Condition			Measured Condition	
Modifier	Worst Condition of:	HS Collar(s)	Modifier	HS Collar(s)
Pole Leaning	-	Yes	Pole Strength	Yes
Bird/Animal Damage	-	Yes	Shell Thickness	Yes
Pole Based Rot	At/below ground level Above ground level	Yes		
Pole Separation	Cracks Pole top feathering	Yes		
Pole Void	Wood loss Hollow heart/pockets present	Yes		

Health score collars have been applied to all of the modifiers such that poor results from a condition inspection or measurement give a health score that is at least the specified value of the collar. The setting of the condition factors and the corresponding health score collars are considered to be reasonable and aligned with both THESL's established practices and the principles of the CNAIM methodology.

The current and future (year 5) health index profile* for wood poles as calculated using the ACA methodology is shown in Figure 1.

* The Health Index banding criteria are those in CNAIM v1.1 where HI has an upper limit of a health score of 4.

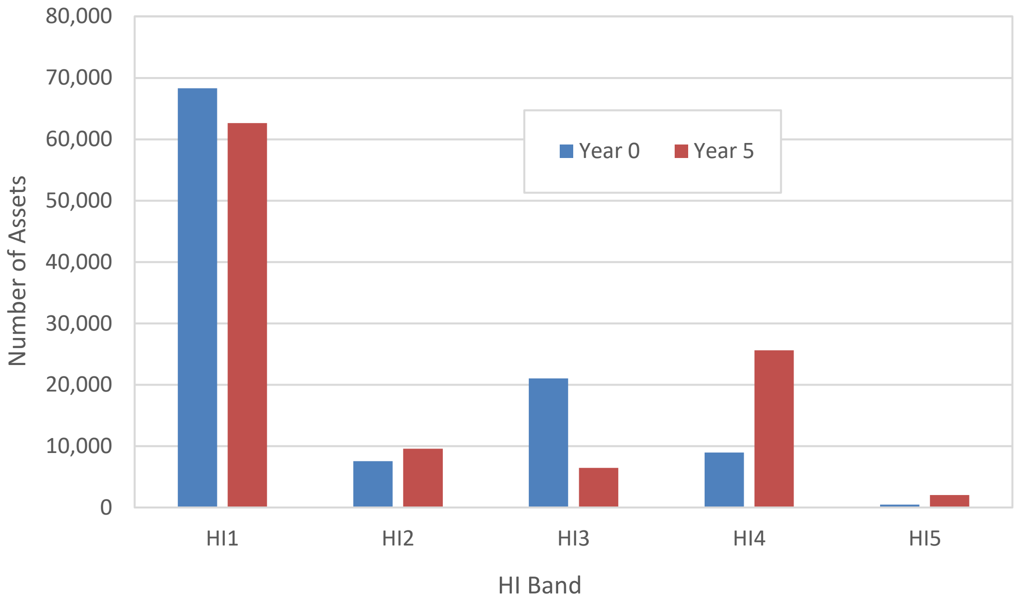

Figure 1 Wood Poles: Current and Future (Year 5) Health Index Profile

The current health index profile seems reasonable given the age profile and condition of the asset population. The 'spike' in the number of wood poles in the HI3 band is driven by assets that have ages beyond the expected life of 45 years.

Just over 2% of the asset population have health score values set through condition collars, mainly due to moderate pole separation (cracks and pole top feathering). This shows a considered approach to the setting of condition collars to identify assets with issues requiring intervention.

The CNAIM methodology includes an additional (reliability) modifier to reflect any issues or observations that are not reflected in the observed and measured condition modifiers. THESL have used this methodology feature in the wood pole model and applied a collar of 7.25 to assets that have been confirmed to be in a poor condition by inspectors in the field. This is considered to be an appropriate use of the reliability modifier mechanism to directly impact asset health where information is available.

Figure 1 shows a slow movement of assets from HI1 to HI2 and HI3 over the next 5 years, with a more rapid progression from HI3. This seems reasonable given the age profile and underlying condition of the asset portfolio and indicates that the health score modifiers have been set appropriately, resulting in a realistic ageing rate for the prediction of health scores into the future.

5.2 Network Transformers

The network transformer model comprises 1,718 assets ranging in age from new to more than 40 years old. The initial health score of each asset is derived from its age, the normal expected life of the asset class (35 years) and a measure of how hard the asset is working (the ratio of peak loading to transformer rating). THESL recognise that there are inaccuracies in the transformer loading data and it is understood that a default is applied to any transformers with a calculated utilisation of more than 200%. This is a valid approach where known inaccuracies and inconsistencies exist in the data sources.

There are 229 assets with an initial health score of 5.5 driven by either the age of the transformer and / or a reduced normal expected asset life due to the high duty that the asset is experiencing. This proportion of assets with a maximum initial score of 5.5 is reasonable given the age profile and high utilisation of some of the transformers.

The model includes both observed and measured condition modifiers as indicated in Table 5. .

Table 5 Network Transformer Model: Observed and Measured Condition Modifiers

Observed Condition			Measured Condition	
Modifier	HS Collar(s)	Comments	Modifier	HS Collar(s)
External Condition of Tank	Yes	Stronger factors and collars for corrosion of the lid and base than for corrosion of the transformer body	Partial Discharge	Yes
Oil Leaks	Yes	Stronger factors and collars for leaks from the base than for leaks not from the base	Temperature Readings	Yes
Connection Condition	No	-		
Primary Switch Condition	Yes	-		

A number of health score collars have been applied such that poor results from a condition inspection or measurement give a health score that is at least the specified value of the collar. The setting of the condition factors and the corresponding health score collars are considered to be reasonable and aligned with both THESL's existing practices and the principles of the CNAIM methodology.

The current and future (year 5) health index profile* for network transformers as calculated using the ACA methodology is shown in Figure 2.

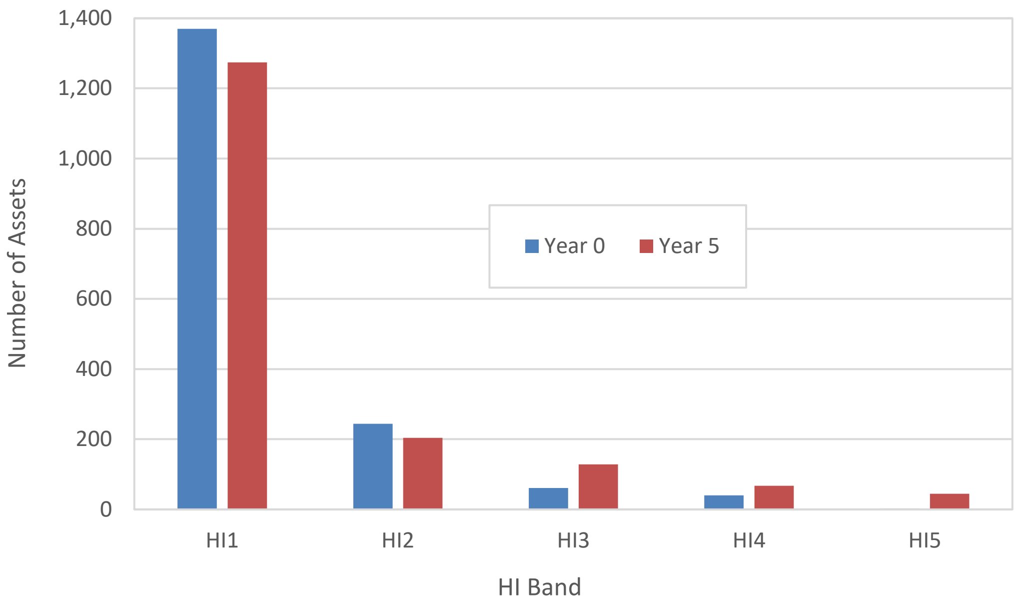

Figure 2 Network Transformers: Current and Future (Year 5) Health Index Profile

* The Health Index banding criteria are those in CNAIM v1.1 where HI has an upper limit of a health score of 4

The current health index profile looks reasonable given the age and condition of the asset population. A small number of assets (44) have health score values set through condition collars, mainly due to corrosion issues and / or significant oil leaks. This shows a considered approach to the setting of health score collars to identify assets with issues requiring intervention.

Figure 2 shows the assets moving slowly through the health index bands over the next 5 years. This seems reasonable given the age profile and underlying condition of the asset portfolio and indicates that the health score modifiers have been set appropriately, resulting in a realistic ageing rate for the prediction of health scores into the future.

5.3 Submersible Transformers

The submersible transformer model comprises 9,161 assets ranging in age from new to more than 40 years old. The initial health score of each asset is derived from its age, the expected life of the asset class (30 years) and a measure of how hard the asset is working (the ratio peak loading to transformer rating). THESL recognise that there are inaccuracies in the transformer loading data and have applied a default to any transformers with a calculated utilisation of more than 150%. This is a valid approach where data inaccuracies exist.

There are 568 assets with an initial health score of 5.5 driven by either the age of the transformer and / or a reduced expected asset life due to the high duty that the asset is experiencing. This proportion of assets with a maximum initial score of 5.5 is reasonable given the age profile and utilisation of some of the transformers.

The submersible transformer model includes three observed condition modifiers as follows:

- External condition of tank (with stronger factors and collars for corrosion of the lid and base than for corrosion of the transformer body).
- Oil leaks (with stronger factors and collars applied to leaks from the base than to leaks not from the base).
- Connection condition. No condition collars are applied.

The setting of the condition factors and the corresponding health score collars are considered to be reasonable and aligned to the principles of the CNAIM methodology.

The current and future (year 5) health index profile* for submersible transformers as calculated using the ACA methodology is shown in Figure 3.

* The Health Index banding criteria are those in CNAIM v1.1 where HI has an upper limit of a health score of 4

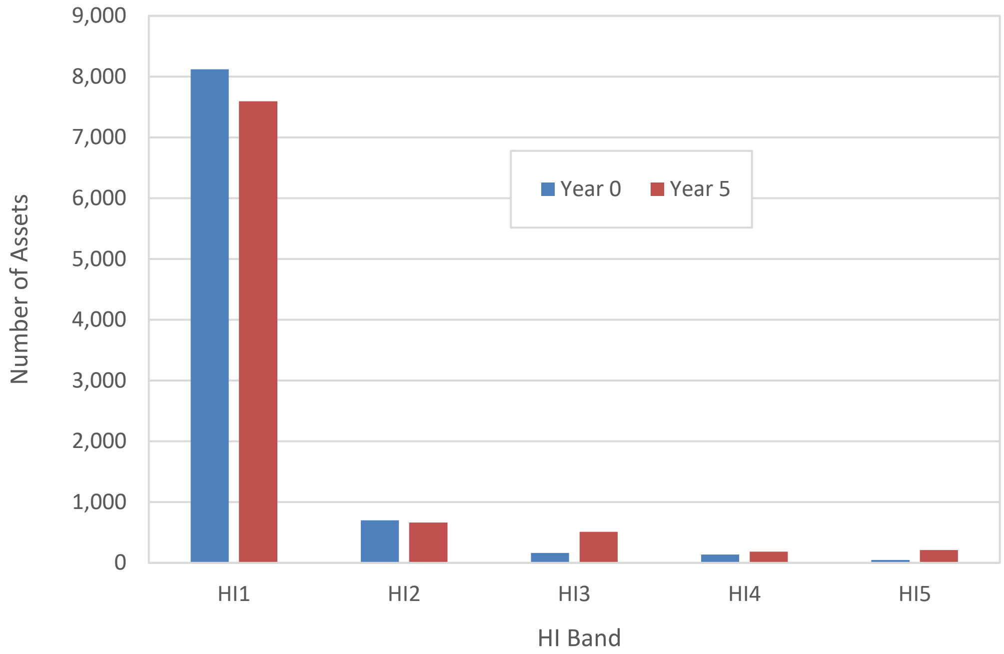

Figure 3 Submersible Transformers: Current and Future (Year 5) Health Index Profile

The current health index profile would appear to be reasonable given the age and condition of the asset population. A small proportion of assets (around 3%) have health score values set through condition collars, mainly due to oil leaks and corrosion issues. This shows a considered approach to the setting of health score collars to identify assets with issues requiring intervention.

Figure 3 shows the assets moving slowly through the health index bands over the next 5 years. Again, this seems reasonable given the age profile and underlying condition of the asset portfolio and indicates that the health score modifiers have been set appropriately, resulting in a realistic ageing rate for the prediction of health scores into the future.

5.4 General Comments

The high-level assessment of THESL's ACA models for wood poles, network transformers and submersible transformers has found the logic, factor evaluation and calculation sequence to align with the principles of the CNAIM methodology. In particular, the results show:

- heath index profiles indicative of an asset population that appears to be maintained and generally in a good condition;
- the proportion of health score results that have been 'forced' by health score collars seems reasonable for the asset populations; and
- acceleration of assets to the HI4 band appears reasonable and aligns with established THESL asset management thinking and existing business processes.

EA Technology understand that THESL are continuing to work on improving data quality. This review has highlighted the following data anomalies:

- The network transformer and submersible transformer models include some unrealistically high utilisation values. THESL have recognised the potential for data inaccuracies and applied default duty factors above threshold transformer utilisations (understood to be 200% in the network transformer model and 150% in the submersible transformer model). This is a valid approach and provides a straightforward way of eliminating questionable data and potentially overstating the heath score and ageing rate for the affected assets.

- It is understood that more than one data source is being used for network transformer utilisation and operating temperature. Some of this data looks suspect, with a number of units apparently delivering 3 times name plate rating having reported maximum operating temperatures in the region of 40°C. This is clearly a data discrepancy and may possibly understate the measured condition modifier and hence the health score of affected assets.
- Wood pole inspection frequency is understood to be conducted on a rolling 10 year cycle. However, the data extract file provided contains condition data collected either in or before 2012. The review has also found that for a small proportion of structures within the population, the nature of the structure material is either unknown, unclear, or 'wood'. Such data gaps and discrepancies are not unusual in asset populations of this size and should reduce over time as more data is collected, resulting in more granular health index profiles.

6. Review of THESL's Probability of Failure, Consequence of Failure, Asset Criticality, and Risk Implementation

Task 3 has involved a review of THESL's ACA derivation of asset probabilities of failure, the determination of consequence of failure values from their broader Value Framework, and the approach to the application of criticality factors in order to calculate risk. Due to the recognised differences in operating and regulatory environment between Ontario and Great Britain, this review has not focused on establishing whether THESL have been able to duplicate the CNAIM methodology's calculation sequence. Instead, it has determined whether the implementation is reasonable and aligned with generally accepted industry practices and the underlying principles of the Common Methodology.

6.1 THESL Failure Mode Definitions

The CNAIM methodology considers functional failures* in the derivation of probability of failure (PoF) and consequences of failure (CoF). These relate to the inability of an asset to adequately perform its intended function and are therefore not solely limited to failures that result in an interruption to supply. Three failure types are included within the CNAIM methodology (incipient, degraded, and catastrophic) and these are used in the evaluation of both PoF and CoF.

THESL have defined three failure modes depending on the asset deterioration stage and corresponding remedial action as listed in Table 6. These failure modes have been applied in the ACA methodology for the derivation of probability of failure and consequence of failure values. The three failure modes align with both THESL's established practices and the principles of the CNAIM methodology and are considered to be appropriate for the evaluation of asset PoF and CoF.

Table 6 THESL Failure Mode Definitions

Failure Mode	Description
Incipient	A failure associated with early-stage asset degradation. Such failures can be resolved through the undertaking of planned corrective action which may require an outage.
Degraded	A failure associated with advanced asset degradation, for which reactive repair would be expected to only have a limited effect. Such failures are likely to result in planned asset replacement.
Outage	A failure associated with advanced asset degradation, which will often result in a sustained outage until unplanned reactive works have been completed.

* Functional failures considered in Common Methodology relate only to those failures directly resulting from the condition of the asset itself; failures of function due to third party activities are not included.

6.2 Probability of Failure

The CNAIM methodology uses a standard relationship between health score and PoF based on a modified cubic relationship as follows:

$$PoF = k \cdot \left(1 + (H \cdot c) + \frac{(H \cdot c)^2}{2!} + \frac{(H \cdot c)^3}{3!}\right)$$

where:

PoF = probability of failure per annum

H = a variable equal to health score, unless health score ≤ 4 and then H = 4

k & c = constants (for a given asset category)

The value of c fixes the relative values of the probability of failure for different health scores (i.e. the slope of the curve) and k determines the absolute value.

Within CNAIM, c has been set to the same value (1.087) for all asset categories and has been selected such that the PoF for an asset with a health score of 10 is ten times higher than the PoF of a new asset.

The value of k has been set for each asset category covered by the CNIAM methodology by considering the number of functional failures in the different failure modes recorded in Great Britain over a five year period.

As the values of k are averaged across the DNOs within Great Britain, it is appropriate for THESL to derive representative values of k for each asset class from the asset populations and known failures in each of the failure mode categories defined in Table 6. During the engagement on THESL's continued CNAIM/CBRM implementation in 2021/22, EA Technology explained the approach to determining k and provided THESL with an Excel spreadsheet* showing a worked example of how to derive a 'composite' value of k from multiple failure modes.

THESL have comprehensive records of historic failures and have been able to derive k values for each of the asset classes covered by the ACA methodology. During the initial review of the probability of failure curves it was found that the calculated PoF values were excessively high for some asset classes. Following a trouble-shooting session with EA Technology asset management specialists, THESL revisited the definition of incipient failures to exclude failures that could be classed as operational defects.

The k values provided by THESL for each of their asset classes have been reviewed as part of Task 3 and the revised definition of incipient failures gives PoF curves that seem credible across all asset classes. It is not meaningful to compare THESL's k values with those in CNAIM given the proportions of each failure type comprising a 'composite' failure, the asset populations and differences in asset management practices; however, the process undertaken to derive representative values of k is considered to be robust and the corresponding PoF curves appear reasonable.

6.3 Consequences of Failure

All of the ACA models developed by THESL include the four consequence categories associated with asset failure that are included within CNAIM: Network Performance, Safety, Financial, and Environmental. Sections 6.3.1 to 6.3.4 below consider each of the defined consequence categories in turn.

* *Derivation of k.xlsx*. Excel spreadsheet provided to THESL by email on 15 April 2021.

The Consequences of Failure methodology in CNAIM is based on the production of a Reference Cost of Failure in each consequence category which represents the 'typical' effects of a failure based on an organisation's experience. Asset-specific modifying factors are then applied to these reference costs in order to reflect the costs associated with a condition-based failure of the specific asset. These factors are generally referred to as criticality factors and are discussed further in Section 6.4.

6.3.1 Network Performance Consequences

In the CNAIM methodology, the Network Performance Consequences of Failure take into account the way in which electrical system operators restore customer supplies following unplanned events and asset failures. THESL's ACA approach to Network Performance CoF appears to directly align with CNAIM with the consideration of three distinct phases of supply restoration that reflect a staged restoration process:

- Phase 1 makes allowance for system redundancy, auto-change-over schemes, intelligent networks, and SMART grid technologies which either prevent reportable supply interruptions or those that act independently and automatically to restore healthy electrical system components before any interruption (duration) is required to be recorded as part of the governing regulatory system.
- Phase 2 is associated with system re-configuration via switching operations in an effort to firstly minimise, and secondly provide a means of isolation for non-serviceable network sections whilst reconnecting more connected customer supplies.
- Phase 3 typically involves activities designed to either repair or replace failed power system assets thereby enabling the integrity of the original system to be restored.

Quantification of Network Performance Consequences of Failure usually involves analysing the number of customer supplies affected by supply interruptions caused by asset failure along with their associated outage durations. Alternatively, system operators need to establish a robust mechanism through which reductions in available system capacity and capability can be determined. For convenience, this quantification often works in terms of domestic supply equivalence and is generally more easily understood.

THESL's ACA quantification of Network Performance CoF is formed using two component parts reflecting the costs of customer interruptions (CIs), and the on-going cost of electrical supply outage duration (CMI). The sum of the blended CI and CMI costs is then multiplied by the probability of interruption before the application of any criticality factors.

THESL have carried out an in-depth evaluation of the information held within their Interruption Tracking Information System (ITIS) relating to historical asset failure, unplanned outage, and emergency response activities. Following the completion of a statistical analysis of the data, THESL have been able to both identify and quantify network performance consequences for each of the failure modes under consideration.

This review has found that in terms of secondary transformers, the Network Performance CoF (outage duration) determinations for fuse replacements, component repairs, and the restoration of supplies through the adoption of alternative 'temporary solutions' straightforward to understand and apply. Transformer replacement is not as intuitive, as the relationship between transformer location and assignment of the closest resource (yard) availability is not as immediately obvious for those unfamiliar with the nuances of the organisation.

Quantification of asset failures are presented in terms of the number of connected customers supplies affected and takes account of the likelihood of electrical protection system success through a statistical determination of the number of multiple supply interruption occurrences on a per failure mode basis. Consideration should be given to extending this form of evaluation into network configurations that possess higher security of supply standards such as n-1 where asset failures do not necessarily result in unplanned outages.

Both CoF calculation stages employ THESL system performance data and financial values which provide a solid basis for defence if challenged. Although highly dependent upon system control data processes, THESL's implementation of this aspect of the ACA modelling process appears to align with the underlying philosophy of CNAIM where asset failures result in unplanned outages.

6.3.2 Safety Consequences

THESL's ACA models have been designed to generate consequence of failure values for events that have the potential to result in loss of life, cause reportable lost time accidents, or inflict damage to a third party's property. It is understood that the approach taken is universally applied across the entire suite of THESL's ACA models.

When considering asset failures which result in fatality, the ACA models calculate the safety consequences of failure differently depending upon whether or not the deceased is a direct employee of the utility. In the instance that direct employees are fatally wounded, the consequence values are based upon figures associated with the Ontario Workplace Safety and Insurance Board (WSIB). The consequence values used to represent fatalities involving members of the general public are also based on WSIB figures and are further supplemented by financial values outlined in the WorkSafe BC Incident Cost Calculator.

Safety consequences of failure associated with lost time incidents are derived using an Exposure Hour Methodology based upon THESL data, with WSIB costs for direct employees of the utility and Government of Canada figures for events not involving employees.

At the present time, safety consequences associated with damage to third party property are not included within the total safety consequence value determination.

The consequence values used within the ACA models are summarised in Table 7 below.

Table 7 ACA Safety Consequences of Failure Inputs

Safety Consequence Category	Probability of Consequence Occurrence	Consequence Value
Fatality	Values set as per CNAIM	Direct Employee $1.6m CAD Member of the Public $1.784m CAD
Lost Time Accident	0.00815%	Direct Employee $15k CAD Member of the Public $6k CAD
Damage to Third Party Property	No data available	Defaulted to $0 CAD

The approach taken to determine the Safety Consequence of Failure values is considered to directly align with the principles outlined within the CNAIM methodology. They appear to be based upon sensible information sources, and as they comprise of recognised industry and government standard figures, would be considered both reasonable and defendable if challenged.

6.3.3 Financial Consequences

The Financial Consequences of Failure in THESL's ACA models are determined by defined asset failure modes as outlined in Section 6.1:

- *Incipient failures*. Financial consequences are based upon the financial figures used to determine the regulatory Rate Case Filing and real-world OPEX expenditures obtained from THESL's historical data.
- *Degraded failure* financial consequences are based upon THESL's standardised unit cost information combined with THESL's previous experience of managing and undertaking capital works.
- *Outage failures*. Financial consequences have been derived from analysis of THESL's historical emergency response figures.

The inclusion of standardised unit costing information is considered to be an appropriate route to determine the Financial Consequences of Failure within the ACA methodology as the values incorporated are both recognisable and defendable in equal measure.

6.3.4 Environmental Consequences

THESL's ACA models consider four different aspects of environmental impact when calculating the Environmental Consequences of Failure. These relate to loss of oil containment, the release of SF_6 insulant gas, the potential effects of asset failures resulting in fire, and the generation of waste.

The environmental consequences for oil and SF_6 releases are treated in the same way. For each failure mode under consideration, an evaluation has been made to determine the likelihood of insulant release; this is currently supported by a worst-case scenario assumption that a total loss of insulant occurs. The product of these values is then multiplied by an environmental contamination/release cost which is used to derive individual environmental consequences.

The environmental consequences associated with fire centre around the potential to ignite oil and are again calculated by first determining a likelihood of fire event occurrence, a representative means of quantifying the impact of any fire event (typically via the conversion to equivalent volume of CO_2 emitted), and the identification of a per unit emission cost.

Fire event probability has been sourced from THESL's Interruption Tracking Information System to identify the number of asset failures that involved fire events as a proportion of the total number of asset failures experienced for each asset class. THESL have then used asset records to determine how much oil assets contain, before using standardised government figures to calculate a financial value for the environmental consequences.

It is understood that THESL are, at the time of writing, not able to accurately determine a satisfactory mechanism through which waste disposal costs can be accurately identified. This is thought to be due in part to the variability of scrap materials on the open market which offsets the total cost of asset decommissioning and disposal. Within the ACA models, therefore, the financial value pertaining to the environmental consequences from generation of waste have been set to a default value such that they do not contribute to the overall Environmental Consequences of Failure calculation.

A summary of the Environmental Consequences of Failure inputs is shown in Table 8 below.

Table 8 ACA Environmental Consequences of Failure Inputs

Category	Calculation Input	Information Source
Oil	Probability of release occurrence	THESL ITIS and Oil Spill Incident Records
	Assumed Volume released (per event)	Assumed complete loss of all asset oil. Source THESL asset records.
	Unit cost (per litre)	Basic Oil Spill Cost Estimation Model (BOSCEM) by the US Environmental Protection Agency
SF_6	Probability of release occurrence	THESL ITIS and EHS data
	Assumed Volume released (per event)	Assumed that all asset SF_6 is lost. Source THESL asset records.
	Unit cost (per kg)	Government of Canada CO_2 emission cost scaled to SF_6 equivalent \$1,195/kg CAD
Fire	Probability of failure causing fire	Derived from THESL's ITIS data
	Volume of fire (CO_2 emission)	Total oil volume taken from THESL asset records converted to CO_2 emission value.
	Unit Cost (CO_2 emission)	Government of Canada \$50/ton CAD
Waste	Waste disposal costs	Not currently used. Defaulted to \$0 CAD

The ACA approach to environmental CoF quantification is regarded as being aligned with CNAIM, and is considered to employ sensible, defendable unit costs and probabilities against each relevant consequence category. The difficulties THESL are experiencing in relation to determining average asset disposal costs are understood, as is the intention to continue to search for a workable solution.

6.4 Asset Criticality

The CoF methodology within CNAIM is based on the production of a Reference Cost of Failure in each consequence category which represents the 'typical' effects of a failure based on DNO experience. Asset-specific modifying factors are then applied to these reference costs in order to reflect the costs associated with a condition-based failure of each asset. These factors are generally referred to as criticality factors.

THESL have followed a similar approach to the CNAIM methodology and considered the application of criticality factors in each of the four consequence categories as discussed in Sections 6.4.1 to 6.4.4 below.

6.4.1 Network Performance Criticality

THESL's ACA models contain a Customer Sensitivity Factor that can be employed to reflect circumstances where the impact of unplanned power outages is increased due to customer reliance on electricity (e.g. customers with health issues such as a dependency on dialysis machines). This criticality factor is currently defaulted to unity, and therefore does not influence the Network Performance Consequences of Failure. THESL are understood to be considering the most appropriate approach to applying the Customer Sensitivity Factor and may introduce it in the future.

For a small number of asset classes, THESL are understood to have introduced an additional criticality factor which considers the accrued labour hours recorded against asset intervention.

Statistical analysis performed by THESL during evaluation of consequences of failure has identified differences in response times depending on where assets are located. For example, there are increased logistical challenges in the downtown area which can lead to increased intervention costs as well as potentially extending the duration of supply interruptions.

The exact way in which this modifying factor has been implemented remains unclear, and care must be taken to avoid double counting when determining financial failure costs. However, if proven internally by THESL to be credible, robust, reliable and statistically significant, it is a clever use of the criticality factor facility and would be considered to be completely aligned with the principles which underpin CNAIM.

6.4.2 Safety Criticality

THESL's ACA models make provision for two inputs to the Safety Criticality Factor: a Traffic Factor and a Size Factor. The Size Factor is currently defaulted to unity as THESL do not believe that the severity of any interaction with a failed asset is influenced by its operating voltage, rating, or physical size.

The Traffic Factor has been introduced to reflect how busy the immediate vicinity around the asset is perceived to be. This factor is set using individual asset risk ratings, which have been derived directly from CNAIM guidance. Therefore, ACA models should increase the safety consequences of assets in densely populated areas such as main throughfares, within close proximity to stadiums etc. The magnitude of the Traffic Factor in the ACA models is not known; however, factors in the range from 0.7 to 2.0 would be regarded as reasonable and aligned to CNAIM principles.

6.4.3 Financial Criticality

THESL have identified that significant differences exist in the cost of undertaking asset replacement depending upon the geographic region in which work is required. Two regions, referred to anecdotally as "Downtown" and "the Horseshoe" have been defined, and a Location Factor has been derived from analysis of THESL's historical material and labour costs.

It is understood that the Location Factor is intended to represent some of the challenges associated with resourcing within THESL, and the availability of specific skillsets in particular areas; e.g. lines teams within the city centre region. If set by individual asset class, such an approach can be made to reflect the additional time required for appropriate resources to make their way to asset failures. However, care must be taken not to overinflate the effects of this phenomenon by double counting. It is considered that if a Location Factor is applied globally (i.e. across all ACA models) then there is a possibility that the calculation of financial risk will be distorted.

For those asset classes where the Financial Consequences of Failure are directly linked to the ratings or capacity of the replacement unit, THESL's ACA models include a Size Factor. This enables the costs associated with asset replacement to be scaled to the size of the failed unit. However, as the ACA calculated costs are currently determined using unit costs this feature is set to apply a default value that does not affect the overall Financial Criticality Factor.

6.4.4 Environmental Criticality

The transformer and switchgear ACA models make provision for two inputs to the Environmental Criticality Factor to account for the location of the asset and the presence of polychlorinated biphenyls (PCBs). THESL have identified that oil filled assets that are contaminated with PCBs are more expensive to dispose of when compared to non-contaminated units and have included a PCB Factor. This has been determined from the ratio of the decontamination cost for a metric ton of soil with PCB oil to the decontamination cost for a metric ton of soil with regular (no PCB) soil and is considered to be reasonable and defendable if challenged.

The second input to the Environmental Criticality Factor is the Location Factor which accounts for the additional clean-up costs associated with assets close to water. It has been determined using the BOSCEM method by dividing the environmental cost of asset failure close to water by the environmental cost of asset failure on dry land. This approach is consistent with the principles of the CNAIM methodology and is considered to be reasonable and defendable if challenged.

6.5 General Comments

The review of THESL's derivation of asset probabilities of failure and the determination of consequence of failure values from their broader Value Framework has found the implementation to be logical and to align with the principles and framework of the CNAIM methodology. In summary:

- THESL have incorporated three failure modes into the ACA methodology which have been defined to align with the company's asset management practices. This approach allows THESL to make use of historical data to evaluate failure rates and costs of remedial action in each of the failure modes.
- THESL have comprehensive records of historic failures and have been able to derive k values for each of the asset classes covered by the ACA methodology. The analysis undertaken is considered to be robust and the corresponding PoF curves appear reasonable.
- The Consequence of Failure categories used by THESL align with those in CNAIM. These capture the key issues affecting electricity network businesses and can be quantified in terms that allow for monetisation within each consequence category, thus enabling the assessment of risk on a comparable basis across all asset categories.
- Reference Costs of Failure and criticality factors have been derived from recognised data sources and are considered to be relevant to THESL's operating environment.
- The approach to determining reference costs of failure and criticality factors is logical and transparent and, where asset failures result in unplanned customer outages, would be considered robust and defendable if challenged.

7. Discussion and Opportunities for Future Enhancements

THESL have made significant progress in the implementation of their ACA methodology since EA Technology's initial engagement in 2017. They have demonstrated a clear understanding of the concepts behind the GB's Common Methodology and have developed probability of failure curves and consequence of failure values that are appropriate to their operating and regulatory environment whilst retaining alignment with the objectives and principles of CNAIM.

THESL's ACA methodology continues to evolve and it is therefore likely that there will be modifications and enhancements as it 'beds-in' (matures) within the company and more inspection data becomes available to inform the models. This is considered to be a natural process in which the models will improve incrementally over time as the benefits of the approach are realised across the organisation.

Sections 7.1 to 7.4 below summarise the key observations from EA Technology's review of THESL's enhancements and customisations to the ACA methodology. In addition, suggestions for future ACA model developments and/or refinements are provided.

7.1 Health Score Derivation

The principles and philosophy upon which the THESL ACA methodology is based make allowance for asset managers and system operators to draw upon their experience to not only identify, but actually define, sub-groups within asset populations where there are known differences in service lives, asset performance, etc. Examples include:

- *Normal Expected Lives*. Variation in service life by user-identified and defined sub-populations would be expected. This offers the opportunity to enhance the granularity of the health score outputs by setting different Normal Expected Lives by, for example, manufacturer, type, period of manufacture, or material (for wood poles).
- *Duty Factor*. The identification of input data fields which influence asset duty factors should be considered, particularly for switchgear asset classes.

The CNAIM methodology has provision for a Measured Condition Modifier to incorporate information gained from diagnostic tests and measurements into the models. Established condition assessment techniques with empirical relationships include thermography, SF6 condition, oil analysis and partial discharge results. These could be incorporated into existing ACA models to improve the quality of calculated health score results and allow more differentiation between assets.

Following the inclusion of additional condition related inputs, the next natural step in developing asset health indices involves the disaggregation of asset systems into sub-components with their own health score assessment. For example, a Station Transformer could be regarded as a 'composite system' made up of a 'transformer' and separate 'tapchanger'. The health score of the overall transformer asset is then derived from a combination of the health scores of both of these sub-components.

7.2 Health Score Calibration

A small number of ACA models including the SCADAMATE Switches, Air Magnetic Circuit breakers, Air blast Circuit breakers, and SF_6 Circuit Breakers have been calibrated to align health score derivations with THESL's tactical asset management practices. Calibration factors are considered to be very aggressive where asset deficiencies are identified, and the models are heavily influenced, if not dependent, upon health score caps and collars.

It is understood that THESL are using this approach at the present time whilst the organisation is building confidence in both the ACA methodology and the outputs from the models. However, the company recognises that this style of model calibration limits the methodology's ability to provide a longer term strategic view of the asset population and intends to review calibration of the condition modifiers in the future.

The underlying CNAIM methodology provides a mechanism such that fundamental indications of empirically proven conditions, perhaps through the existence of Operational Restrictions, may be linked to a Reliability Modifier that directly impacts the asset health score. The use of a Reliability Modifier may offer a potential solution that could help provide a more strategic view of asset classes such as SCADAMATE Switches, Air Magnetic Circuit breakers, Air blast Circuit breakers, and SF_6 Circuit Breakers.

7.3 CoF Determination

THESL appear to have good asset information and a wide range of both fault data and asset failure information. These data sources have been used to perform a number of statistical analyses and evaluations that in turn have informed the ACA methodology.

The following areas have been noted during the review process where refinements to the determination of network performance and environmental consequences could be incorporated in the future:

- The existing ACA methodology for the quantification of Network Performance CoF works well for asset failures that result in unplanned outages and electrical supply interruptions. However, for network configurations that contain redundancy or possess higher levels of supply security and may not result in power outages, the current quantification method is likely to understate the system level risk when asset failure occurs. It is recommended that THESL consider how asset failures in such circumstances are quantified and incorporated into the ACA methodology.
- It is understood that there is an absence of reliable data relating to volumes of electrical asset insulant loss resulting from asset failures and the ACA methodology assumes that a total loss of insulant containment will take place as a result of failure. This assumption will hold true for distribution voltage switchgear but is unlikely to be an accurate portrayal of either EHV switchgear with multiple insulant chambers or transformer oils, and therefore is likely to overstate the Environmental Consequences of Failure for such assets. THESL may wish to consider exploring this area in more detail in the future.

The availability of good asset data provides an opportunity for increased accuracy in consequence quantification as even basic knowledge of asset makes, types and designs can be exploited when calculating the financial impacts associated with different types of asset failure. For example, the inclusion of weights and measures stated on manufacturer nameplates could be used to calculate volumes of waste generated and insulant losses; this would provide more granularity to the ACA model outputs.

THESL recognise that they have information sources which could be further exploited to provide additional input data in the derivation of consequences of failure. It is understood that THESL intend to explore this area in the future to refine and enhance the outputs from the ACA models.

7.4 Criticality

When determining the Safety Consequences of Failure, THESL have successfully employed a risk based locational rating referred to as a 'Traffic Factor' as a criticality. Unless they form part of a statutory collection requirement, or are generated by other departments within the business, input parameters like this are valuable, but potentially very expensive to collect and difficult to maintain.

One observation made during this review is the absence of any electrical system criticalities that associate assets with either strategic, commercially sensitive or contingency related circuits. Such criticalities can be used to reflect reductions in system level integrity or possess the potential to cause major supply disruption, and therefore may be subject to differences in either operational or working practices. This may influence both Network Performance and Financial Consequences of Failure.

REPORT

Reimagine tomorrow.

Toronto Hydro-Electric Service Limited: 2018 Value of Service Study

Submitted to Toronto Hydro-Electric Service Limited

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1 Executive Summary

Nexant, Inc. was retained by Toronto Hydro-Electric Service Limited (THESL) to conduct its 2018 Value of Service (VOS) study to estimate the costs customers incur during power outages. This research project was designed to collect detailed outage cost information from THESL's residential, small and medium business (SMB), and large commercial and industrial (C&I) customer classes. This report summarizes the methodology and results of the study.

The primary objective of the VOS study was to estimate system-wide outage costs by customer class. The VOS analyses are based on data from three separate surveys (one for each customer class) conducted between January and April, 2018. The responses were used to estimate the value of service reliability for each customer segment, using procedures that have been developed and validated over the past 25 years by the Electric Power Research Institute (EPRI) and other parties.[1]

1.1 Response to Survey

Table 1-1 shows the total number of completed surveys by customer class and the target sample size for each class. The response rate among residential customers was strong, as over 1,000 customers completed surveys either online or via mail, exceeding the target of 800. The response rate for small and medium business customers was lower than expected. Even after increasing the incentive and drawing an additional sample, the total number of completed surveys was only 245. The study results are valid, but obtaining results by smaller geographic regions within the service territory (as with residential customers) was not feasible and the confidence bands are wider than they otherwise would have been if the targets had been reached. For large C&I customers, Nexant scheduled and conducted onsite interviews covering 100 entity/service address combinations, which was the sample design target for this customer class. In some cases, all of the data needed for the outage cost estimates was not available at the interview—either because the interviewee did not have it readily available or was not willing to disclose it. Nexant was able to follow up after the interview and obtain the necessary data for a number of customers, but was not able to obtain it for 16 of them. The number of complete data points for large C&I was thus 84.

Table 1-1:
Total Number of Completed Surveys by Customer Class

Customer Class	Target	Completed Surveys
Residential	800	1061
Small/Medium Business	800	245
Large Commercial & Industrial	100	84

[1] Sullivan, M.J., and D. Keane (1995). *Outage Cost Estimation Guidebook*. Report no. TR-106082. Palo Alto, CA: EPRI.

1.2 Outage Cost Estimates

Table 1-2 provides the cost per outage event estimates by customer class. Cost per outage event is the average cost per customer incurred from each outage duration. Given the dynamic survey instrument design which accounted for historical outage onset times, these values represent the average outage cost across all time periods. For a 1-hour outage, large business customers experience the highest cost ($71,808) and residential customers experience the lowest cost ($10.87).

Table 1-2:
Cost per Outage Event Estimates by Customer Class

Outage Duration	Residential ($/Event)	SMB ($/Event)	Large Business ($/Event)	Blended ($/Event)
1 minute	$8.45	$257.38	$32,438	$51.24
1 hour	$10.87	$857.84	$71,808	$131.81
4 hours	$17.56	$2,142.39	$275,182	$381.77
8 hours	$23.35	$4,098.01	$379,381	$626.90
24 hours	$34.53	$8,426.27	$992,647	$1,412.73

Figure 1-1 and Table 1-3 show cost per average kW by customer class. Cost per average kW is the cost per outage event normalized by average customer demand among respondents. This metric is useful for comparing outage costs across segments because it is normalized by customer demand.

Figure 1-1:
Cost per Average kW Estimates by Customer Class

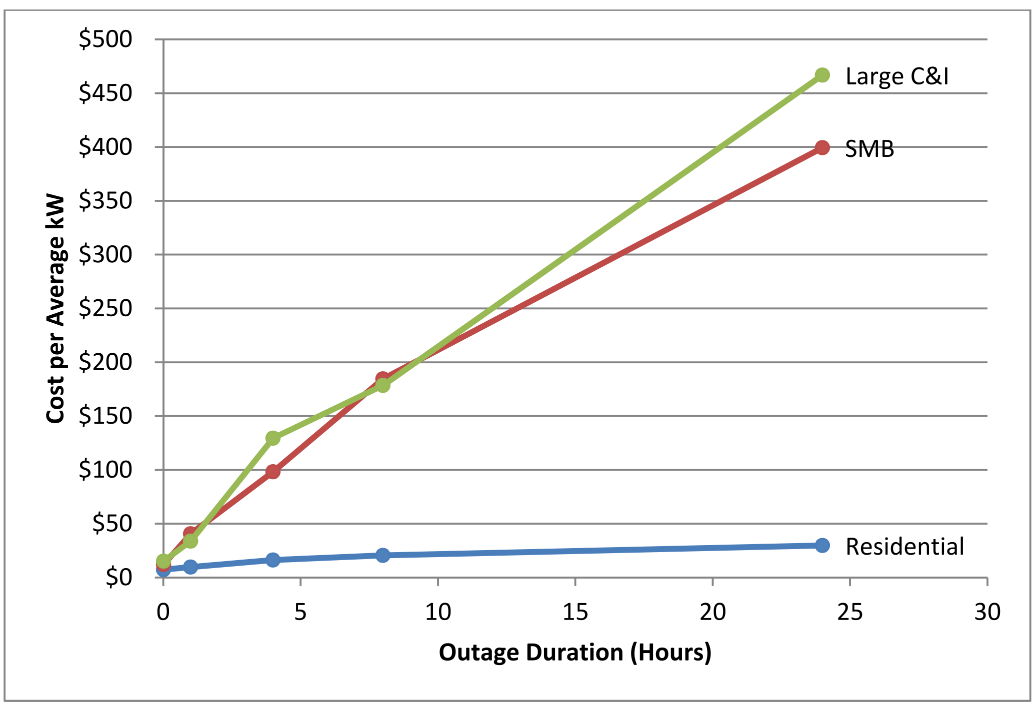


Table 1-3:
Cost per Average kW Estimates by Customer Class

Outage Duration	Residential ($/kW)	SMB ($/kW)	Large Business ($/kW)	Blended ($/kW)
1 minute	$7.31	$12.04	$15.25	$12.80
1 hour	$9.78	$40.68	$33.77	$33.14
4 hours	$16.32	$98.29	$129.41	$94.50
8 hours	$20.53	$184.57	$178.41	$153.83
24 hours	$29.80	$399.42	$466.81	$355.23

Table 1-4 provides the cost per unserved kWh estimates by customer class. Cost per unserved kWh is the cost per outage event normalized by the expected amount of unserved kWh for each outage scenario. This metric is useful because it can be readily used in planning applications, for which the amount of unserved kWh as a result of a given outage is commonly available. At 1-minute, cost per unserved kWh is at its maximum for each region and customer class because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. As duration increases, cost per unserved kWh decreases steeply because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate.

Cost per unserved kWh is useful, as it provides an "apples-to-apples" comparison of how customers value electric service versus what they pay for electric service. For all 4 customer classes and all outage durations, customers place a substantially higher value on an unserved kWh than what they would have paid if that electricity had been delivered. Residential customers experience an outage cost of $5.34 per unserved kWh for a 4-hour outage and $1.75 per kWh for a 24-hour outage, which are lower than the other customer classes, but still substantially higher than what they pay per kWh.

Table 1-4:
Cost per Unserved kWh Estimates by Customer Class

Outage Duration	Residential ($/kWh)	SMB ($/kWh)	Large Business ($/kWh)	Blended ($/kWh)
1 minute	$616.11	$722.43	$915.28	$768.06
1 hour	$13.21	$40.68	$33.77	$33.14
4 hours	$5.34	$24.57	$32.35	$23.63
8 hours	$3.55	$23.07	$22.30	$19.23
24 hours	$1.75	$16.64	$19.45	$14.80

Table 1-5 provides the duration cost per unserved kWh estimates by customer class. Toronto Hydro uses duration costs for its planning activities. This metric considers the cost of an outage event to be the full cost of the outage event minus the cost for a momentary, 1-minute outage. The duration cost for a 1-minute outage is thus always $0. The duration cost per unserved kWh is the duration cost per outage event normalized by the expected amount of unserved kWh.

Table 1-5: Duration Cost per Unserved kWh Estimates by Customer Class

Outage Duration	Residential ($/kWh)	SMB ($/kWh)	Large Business ($/kWh)	Blended ($/kWh)
1 minute	$0.00	$0.00	$0.00	$0.00
1 hour	$2.94	$28.47	$18.51	$20.26
4 hours	$2.77	$21.62	$28.54	$20.45
8 hours	$2.27	$21.62	$20.39	$17.66
24 hours	$1.32	$16.13	$18.81	$14.26

Toronto Hydro was seeking a single, per-hour cost based on historical outages and Table 1-6 provides these "blended duration costs." The table shows these figures for different types of outages in Toronto Hydro service territory from 2010 to 2017. The "Outages Included" column shows which types of outages were included in the blended cost. All outages were categorized by Toronto Hydro as either "Momentary," "Planned," or "Sustained." Given that the results of this study are only valid for outages lasting 24 hours or less, all outages greater than 24 hours were excluded from the calculations. Within each outage type, outages could also be classified as "Loss of Supply Events" or could have occurred on "Major Event Days." These subcategories of outages were either left in the dataset or excluded, depending on the calculation.

The "Event Cost" column shows the average event cost of the outages in the dataset, based on the blended estimates in Table 1-5 and weighted by the number of customers impacted by the outage. The "Duration Event Cost" column shows the weighted average duration event cost, which is the event cost minus the blended 1-minute event cost estimate of $51.24. The "Duration" column shows the weighted average outage duration. The two "Hourly Cost" columns show each event cost per hour, or the "Event Cost" columns divided by the "Duration" column. Depending on the types of outages included, the weighted average duration ranges from 2.9 to 3.6 hours. The hourly event costs are within a relatively tight range, varying from $84.31 to $89.78, while the hourly duration event costs range from $69.94 to $71.87.

Table 1-6: Blended Duration Cost Based on Historical Outage Durations

Outages Included*	Subset of Outages Excluded	Event Cost		Duration (Hours)	Hourly Cost	
		Event Cost	Duration Event Cost		Hourly Event Cost	Hourly Duration Event Cost
Sustained	-	$288.96	$237.72	3.39	$85.32	$70.19
Sustained	Loss of Supply Events	$300.72	$249.48	3.57	$84.31	$69.94
Sustained	Major Event Days	$256.56	$205.32	2.86	$89.60	$71.70
Sustained	Loss of Supply Events, Major Event Days	$272.70	$221.46	3.09	$88.23	$71.65
Sustained, Planned	-	$288.44	$237.20	3.37	$85.54	$70.34
Sustained, Planned	Loss of Supply Events	$299.77	$248.53	3.54	$84.57	$70.11
Sustained, Planned	Major Event Days	$256.81	$205.57	2.86	$89.78	$71.87
Sustained, Planned	Loss of Supply Events, Major Event Days	$272.50	$221.26	3.08	$88.45	$71.82

* Only includes outages up to 24 hours in duration

Interruption costs for THESL are lower than those of other utilities for which recent studies have been conducted - notably Pacific Gas & Electric (PG&E) in 2012 and Southern California Edison (SCE) in 2019. The shape of THESL's outage cost distributions are similar to those of other studies, but they are lower in magnitude. Looking specifically at the survey data from THESL and SCE, significant differences exist in the underlying populations for the two utilities, making comparisons of the interruption costs tenuous. For example, Toronto's non-residential customer population comprises different industry types and the customers had higher annual consumption than SCE. This suggests that interruption costs from areas other than Toronto should not be used to estimate THESL's customer interruption costs.

1.3 Impact of Outage Timing

This study provided useful information on how outage costs vary across season and different times of the day. For the residential and SMB analyses on the impact of outage timing, onset times were aggregated into four key time periods with distinct costs per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

With fewer observations in the large C&I segment, onset times were aggregated into two key time periods as the analysis could not identify clear trends within the more granular time periods used for residential and SMB customers. The two key time periods for large C&I customers were:

- Morning and Afternoon (7 AM to 5 PM); and
- Evening and Night (6 PM to 6 AM).

These groups of onset times were further divided among summer and winter for all three customer classes. Figure 1-2 provides the relative cost per outage event estimates for summer and Figure 1-3 provides the estimates for winter, which were derived from the customer damage functions described in Appendix A. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each outage cost estimate in Section 1.2 (referred to as the "base value"). As shown in the figure, outage costs for SMB and large C&I customers are sensitive to onset time. SMB outage costs vary from 46.6% lower than the base value on a summer evening to 80.6% higher on a winter morning. SMB outages in summer and winter mornings have the highest percentage increase as these outages likely start and end during normal business hours, potentially disrupting an entire day of work. Large C&I outage costs vary from 59.2% lower during summer nights to 18.3% higher during winter days. Considering that non-residential outage costs vary substantially depending on the onset time, it is important that planning applications apply these relative values.

Figure 1-2:
Relative Cost per Outage Event Estimates by Onset Time and Customer Class – Summer

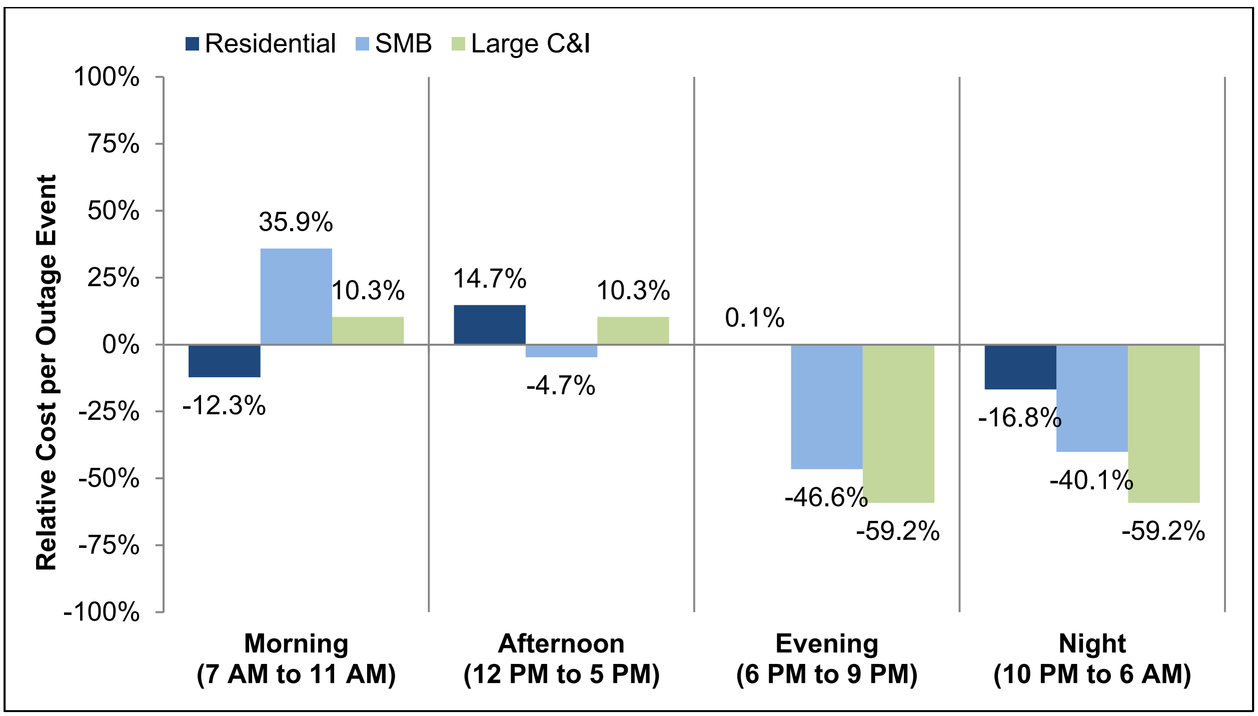
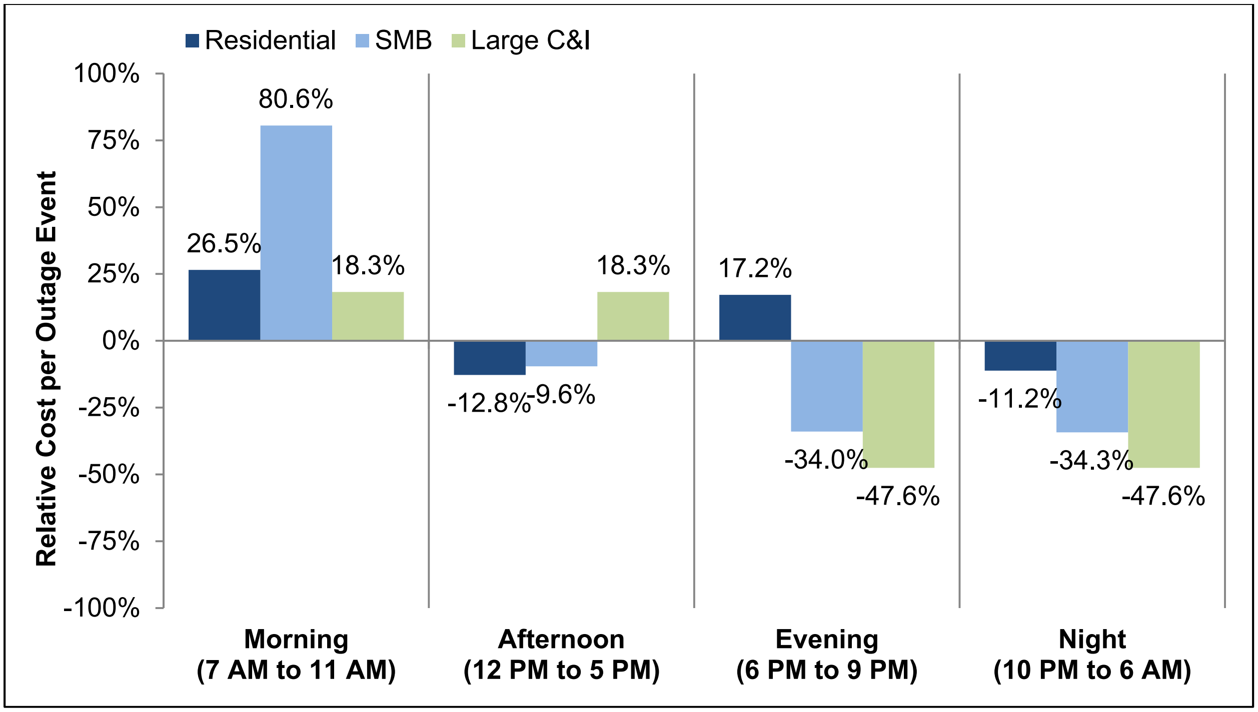


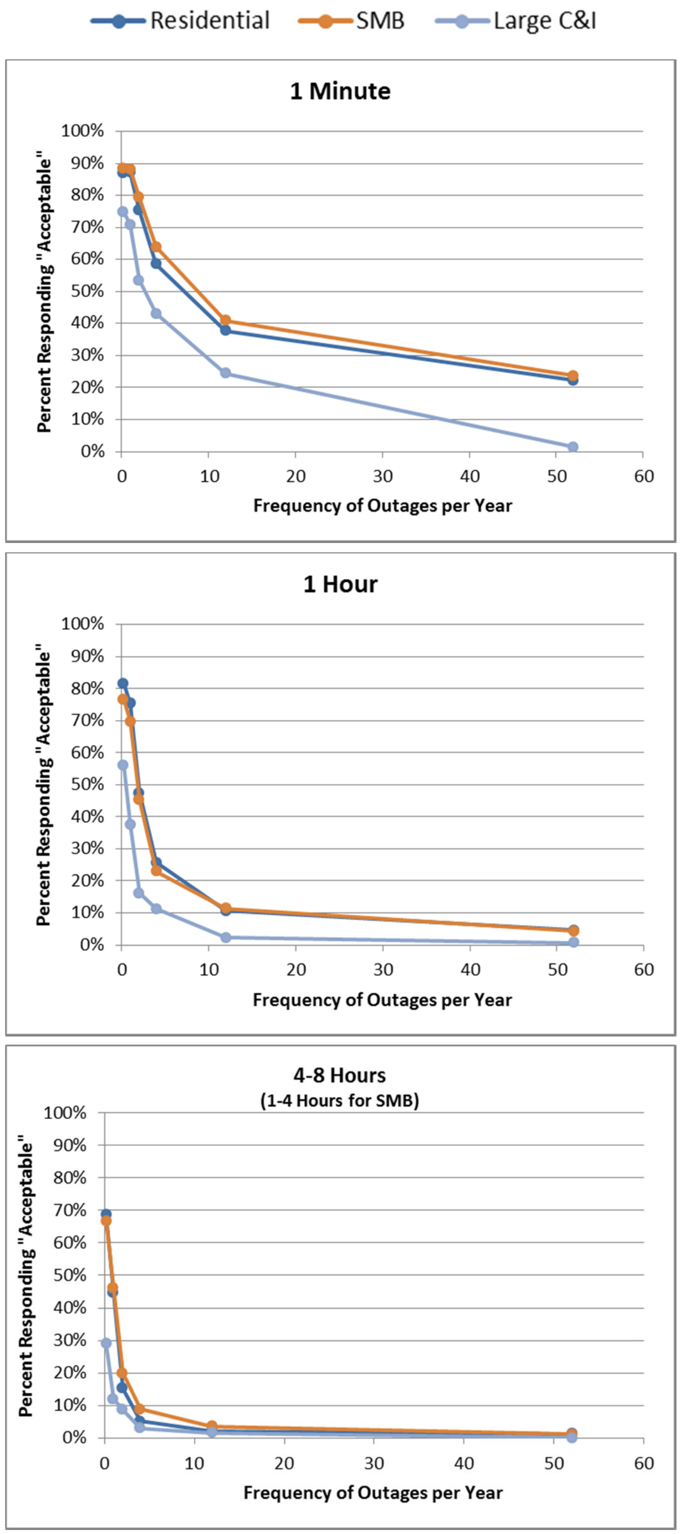
Figure 1-3:
Relative Cost per Outage Event Estimates by Onset Time and Customer Class – Winter



1.4 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 1-4 shows the percent of customers rating each combination of outage frequency and duration as acceptable. As expected, a customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Large C&I customers have a higher standard than residential and SMB customers for what level of reliability is considered acceptable.

Figure 1-2:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable by Customer Class



2 Introduction

Nexant, Inc. was retained by Toronto Hydro-Electric Service Limited (THESL) to conduct its 2018 Value of Service (VOS) study – research to estimate the costs customers incur during power outages. This research project was designed to collect detailed outage cost information from THESL's residential, small and medium business (SMB), and large commercial and industrial (C&I) customer classes. This report summarizes the methodology and results of the study. The primary objective of the VOS study was to estimate system-wide outage costs by customer class.

As VOS cannot be measured directly, it is estimated from outage cost surveys of utility customers. These cost estimates can be used to assess the cost-effectiveness of investments in generation, transmission and distribution systems and to strategically compare alternative investments in order to determine which provides the most combined benefits to the utility and its customers. This comprehensive approach to valuing reliability, commonly known as "value-based reliability planning," has been a well-established theoretical concept in the utility industry for the past 30 years.[2] With the methodology employed in this study, the results can be directly applied to utility investments.

The responses were used to estimate the value of service reliability for each customer segment, using procedures that have been developed and validated over the past 25 years by the Electric Power Research Institute (EPRI) and other parties.

2.1 Study Methodology

The VOS analyses are based on data from in three separate surveys (one for each customer class) conducted between January and April, 2018. This survey methodology has been implemented by many electric utilities throughout the United States over the past 25 years. This study and the prior studies employed a common survey methodology, including sample designs, measurement protocols, survey instruments and operating procedures. This methodology is described in detail in EPRI's Outage Cost Estimation Guidebook.[3] The results of 34 prior studies conducted using this methodology are part of a meta-analysis of nationwide outage costs that is summarized in a 2015 report by Lawrence Berkeley National Laboratory (LBNL).[4]

2.2 Economic Value of Service Reliability

The purpose of VOS research is to measure the economic value of service reliability, using information regarding outage costs as a proxy. Under the general theory of welfare economics, the economic value of service reliability is equal to the economic losses that customers

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[2] For an early paper on value-based reliability planning, see: Munasinghe, M. (1981). "Optimal Electricity Supply, Reliability, Pricing and System Planning." Energy Economics, 3: 140-152.

[3] Sullivan, M.J., and D. Keane (1995). *Outage Cost Estimation Guidebook*. Report no. TR-106082. Palo Alto, CA: EPRI.

[4] Sullivan, M. J., Schellenberg, J. & Blundell, M., 2015. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, Berkeley, CA: Lawrence Berkeley National Laboratory.

experience as a result of service interruptions. The history of efforts to measure customer outage costs goes back several decades. In that time, several approaches have been used. These include:

- Scaled macro-economic indicators (i.e., gross domestic product, wages, etc.);
- Market-based indicators (e.g., incremental value of reliability derived from studies of price–elasticity of demand for service offered under non-firm rates); and
- Survey-based indicators (i.e., cost estimates obtained from surveys of representative samples of utility customers).

The most widely used approach to estimating customer outage costs is through analysis of data collected via customer surveys. In a customer outage cost survey, a representative sample of customers is asked to estimate the costs they would experience given a number of hypothetical outage scenarios. In these hypothetical outage scenarios, key characteristics of the outages described in these scenarios are varied systematically in order to measure differential effects of service outage events with various different characteristics. A variety of statistical techniques are then used to identify and describe the relationships between customer economic losses and outage attributes.

Survey-based methods are generally preferred over the other measurement protocols because they can be used to obtain outage costs for a wide variety of reliability conditions not observable using the other techniques. These methods were selected for use for this THESL VOS study.

2.3 Valuation Methods

Two basic valuation methods are used to measure outage costs in the surveys – direct cost measurement and willingness-to-pay (WTP). Direct cost measurement techniques involve asking customers to estimate the direct costs they will experience during a service outage. WTP measurement techniques involve measuring the amount customers would be willing to pay to avoid experiencing the outage. In both approaches, the surveys ask respondents to provide these estimates for a number of outage scenarios, which vary in terms of the characteristics of the event.

2.3.1 Direct Cost Measurement

Nexant used direct cost measurement for non-residential customers (SMB, and large C&I), as outage costs for these customers are more tangible and much less difficult to estimate directly. At its most general level, the direct cost of an outage is defined as follows:

$$\begin{aligned} Direct\ Cost = Value\ of\ Lost\ Production + Outage\ Related\ Costs \\ - Outage\ Related\ Savings \end{aligned}$$

The *Value of Lost Production* is the amount of revenue the surveyed business would have generated in the absence of the outage minus the amount of revenue it was able to generate given that the outage occurred. It is the business's net loss in the economic value of production after their ability to make up for lost production has been taken into account. It includes the entire cost of making or selling the product as well as any profit that could have been made on the production.

Outage Related Costs are additional production costs directly incurred because of the outage. These costs include:

- Labor costs to make up any lost production (which can be made up);
- Labor costs to restart the production process;
- Material costs to restart the production process;
- Costs resulting from damage to input feed stocks;
- Costs of re-processing materials (if any); and
- Cost to operate backup generation equipment.

Outage Related Savings are production cost savings resulting from the outage. When production or sales cannot take place, there are economic savings resulting from the fact that inputs to the production or sales process cannot be used. For example, during the time electric power is interrupted, the enterprise cannot consume electricity and thus will experience a savings on its electric bill. In many cases, savings resulting from outages are small and do not significantly affect outage cost calculations. However, for manufacturing enterprises where energy and feedstock costs account for a significant fraction of production cost, these savings may be quite significant and must be measured and subtracted from the other cost components to ensure outage costs are not double counted. These savings include:

- Savings from unpaid wages during the outage (if any);
- Savings from the cost of raw materials not used because of the outage;
- Savings from the cost of fuel not used; and
- Scrap value of any damaged materials.

In measuring outage costs, only the incremental losses resulting from unreliability are included in the calculations. Incremental losses include only those costs described which are above and beyond the normal costs of production. If the customer is able to make up some percentage of its production loss at a later date (e.g., by running the production facility during times when it would normally be idle), the outage cost does not include the full value of the production loss. Rather, it is calculated as the value of production not made up plus the cost of additional labor and materials required to make up the share of production eventually recovered.

2.3.2 Willingness-to-Pay Approach

Cost estimates for the residential segment are based on a WTP question, as residential customers do not experience many directly measureable costs during an outage. Considering that most of the outage cost for residential customers is a result of inconvenience or hassle, WTP is a better representation of their underlying costs. The WTP approach to outage cost estimation is quite different than the direct cost measurement approach. Rather than asking what an outage would cost the customer, the WTP approach asks how much the customer would pay to avoid its occurrence. This technique employs the concept of compensating valuation, where customers are asked to estimate the economic value that would leave their welfare unchanged compared to a situation in which no outage occurred. This approach is especially useful when intangible costs are present, which by their nature are difficult to estimate using the direct cost measurement approach.

2.4 Report Organization

The remainder of this report proceeds as follows:

- **Section 3 – Survey Methodology:** This section covers the survey methodology, including details on the survey implementation approach by customer class, survey instrument design, sample design and data collection procedures for each customer class.
- **Section 4 – Outage Cost Estimation Methodology**: The results of this study focus on the following six metrics: cost per outage event, cost per average kW, cost per unserved kWh, duration cost per outage event, duration cost per average kW, and duration cost per unserved kWh. This section on the outage cost estimation methodology explains what each of these five key metrics represents, how they are calculated from the survey data and how they are related to each other.
- **Sections 5 through 8 – Results**: These four sections provide the results for residential customers (Section 5), small/medium business (Section 6), large C&I (Section 7), and blended (Section 8). Results are presented for the metrics defined in Section 4. Each section concludes with results related to the level of reliability that each customer class considers acceptable.
- **Appendix A – Customer Damage Functions:** This appendix details the customer damage functions, which are econometric models that predict how outage costs vary across customers, outage duration and other outage characteristics.
- **Appendices B through D – Survey Instruments:** These appendices contain the survey instruments used for the study for each customer class.

3 Survey Methodology

Table 3-1 provides an overview of the survey implementation approach by customer class. Residential customers were recruited with a letter that encouraged them to go online to complete the survey (the letter included a link to the online survey along with a unique access code specific to each customer). If a residential customer did not complete the survey online, Nexant arranged to have a paper copy sent to the customer's mailing address. Customers for whom THESL had email addresses were sent an email with a direct link to that customer's unique online survey. SMB customers were recruited by telephone. They were encouraged to fill out the survey online, but were also offered the option of receiving a paper survey to complete and submit through the mail. If the customer preferred to go online to complete the survey, a link to the online survey and a unique access code specific to each customer were provided in an email. Large C&I customers were recruited by telephone and received an in-person interview. THESL key account representatives assisted with recruitment by contacting large C&I customers to inform them of the study and request their participation.

Although all survey instruments included variations of willingness-to-pay (WTP) and direct cost questions, the results in Sections 5 through 8 are based on the valuation methods listed in Table 3-1. Cost estimates for the residential segment are based on a WTP question, as residential customers do not experience many directly measureable costs during outages lasting 24 hours or less. Considering that most of the outage cost for residential customers is due to inconvenience or hassle, WTP is a better representation of their underlying costs. For SMB and large C&I customers, direct cost measurement is the preferred valuation method, as their outage costs are more tangible and much less difficult to estimate directly.

Table 3-1:
Survey Implementation Approach by Customer Class

Customer Class	Sample Design Target	Recruitment Method	Data Collection Approach	Valuation Method	Incentive Provided
Residential	800	Letter/Email	Mail/Internet Survey	WTP	$10
SMB	800	Telephone	Mail/Internet Survey	Direct Cost	$50/$100
Large Business	100	Telephone	In-person Interview	Direct Cost	$150

3.1 Survey Instrument Design

The survey instrument asked customers to estimate interruption costs for six different hypothetical outage scenarios. The outage scenarios were described by five different factors: season, time of week, start time, end time, and outage duration. For each customer, the start time was the same for all scenarios to avoid confusion. Table 3-2 summarizes a set of outage scenarios for one particular customer. Each survey used either summer or winter as the season. Half of the surveys had summer as the season for scenarios A-E and winter as the season for scenario F. The other half had the seasons reversed. Each survey contained two scenarios with a 4-hour duration—one for summer and one for winter. The time of week was "Weekday" for all scenarios, as this survey was designed to facilitate modeling of seasonal variation instead of weekend/weekday variation. The survey instruments are included as appendices in case more detail is required on other aspects of the survey.

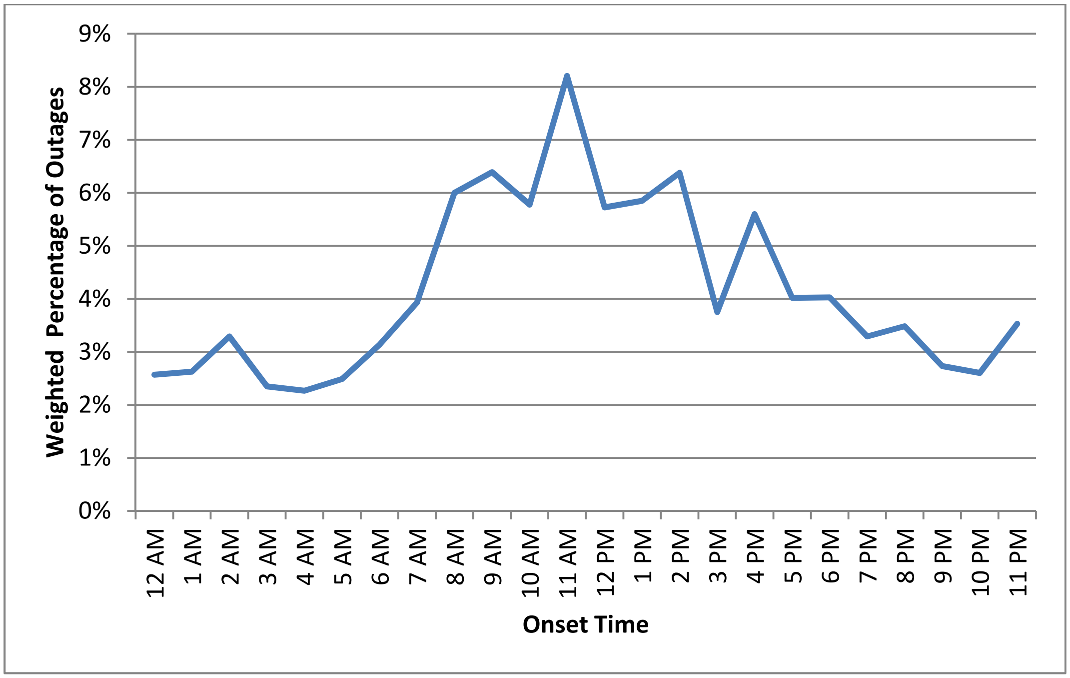
Table 3-2: Example Set of Outage Scenarios

Scenario	Season	Time of Week	Start Time	End Time	Duration
A	Summer	Weekday	11:00 AM	3:00 PM	4 hours
B	Summer	Weekday	11:00 AM	11:01 AM	1 minute
C	Summer	Weekday	11:00 AM	Noon	1 hour
D	Summer	Weekday	11:00 AM	7:00 PM	8 hours
E	Summer	Weekday	11:00 AM	11:00 AM (Next Day)	24 hours
F	Winter	Weekday	11:00 AM	3:00 PM	4 hours

The distribution of hypothetical onset times among survey respondents was determined by examining the historical distribution of outages for THESL from 2010-2017. Figure 3-1 shows the distribution of outage onset times for sustained outages during this time period.[5] The outages were weighted by the number of customers impacted by the outage. The most common weighted onset time was the 11:00 AM hour, which accounted for just over 8% of impacted customers. The survey instrument randomized the outage scenarios in proportion to the distribution of onset times in Figure 3-1. The outage cost estimates provided in Sections 5 through 8 are thus representative of the average outage cost across all time periods.

[5] The distribution excludes outages categorized by THESL as "momentary" or "planned." It also excludes outages occurring on major event days during the period, or for which the cause was loss of supply.

Figure 3-1:
Distribution of Sustained Outages by Onset Time
Weighted by Total Customers Interrupted (2010-2017)



3.2 Sample Design

The study aimed for the following number of completed surveys for each customer class:

- 800 residential customers;
- 800 SMB customers;
- 100 large C&I customers.

Before detailing the sample design methodology and how these sample points were distributed among usage categories, it is important to note that a “customer” refers to a unique combination of “entity name” and “service address” in THESL’s customer database. For residential customers, there was generally only one account ID associated with each unique combination. For non-residential customers, there could be multiple account IDs for an entity name-service address combination. When customers completed an outage cost survey, they provided cost estimates for the specific service address. Usage and customer contact information were aggregated across all of the accounts associated with each entity at each service address and then the customers were sampled.

Nexant stratified each customer class by the log of usage (a proxy for outage cost) by employing a two-step process to achieve an optimal sample stratification scheme. In the first step, Nexant identified the optimal stratum boundaries using the Dalenius-Hodges method. Next, it determined the optimal allocation among the Dalenius-Hodges strata using the Neyman allocation. This two-step approach is particularly useful for measuring skewed populations and maximizes survey precision for a given sample size and number of strata. This sampling approach is necessary as the distribution of usage per customer is highly skewed.

Tables 3-3, 3-4, and 3-5 summarize the sample designs for residential, SMB, and large C&I customers respectively. The residential and SMB customer classes each had four sample strata—labeled as ‘usage categories’ in the leftmost column of each table. The large C&I customer class was divided into three strata. For each of the customer classes, the sample stratification method led to the largest usage category having a larger percentage of customers in the sample than in the population. This allowed the sample to capture the higher and more variable outage costs for customers in those categories.

Table 3-3:
Sample Design Summary – Residential

Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
0 to 0.25	62,103	9%	204	26%
0.25 to 0.57	194,060	30%	196	24%
0.57 to 1.1	252,994	39%	191	24%
1.1 and above	145,816	22%	208	26%
	654,973	**100%**	**800**	**100%**

Table 3-4:
Sample Design Summary – SMB

Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
0 to 1.35	14,668	23%	204	26%
1.35 to 4.78	22,380	35%	196	25%
4.78 to 25.8	17,499	27%	191	24%
25.8 and above	9,146	14%	208	26%
	63,693	**100%**	**800**	**100%**

Table 3-5:
Sample Design Summary – Large Business

Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
235 to 911	158	34%	27	27%
912 to 1934	189	41%	31	31%
1935 and above	113	25%	42	42%
	460	**100%**	**100**	**100%**

3.3 Data Collection Procedures

This section summarizes the data collection procedures for each customer class.

3.3.1 Residential Customers

The residential survey was conducted online and via mail. It was distributed to the target respondents in two waves. In the first wave, respondents received a cover letter on THESL stationery explaining the purpose of the study and requesting their participation. This letter also contained a URL and unique respondent ID number so that respondents could complete the survey online. Approximately two weeks after the first wave was mailed, respondents who did not complete the online survey received a reminder letter with a paper copy of the survey. The letters and survey packet included an 800 number that respondents could call to verify the legitimacy of the survey and ask questions. Customers who completed the survey were sent a $10 incentive cheque in the mail.

3.3.2 Small & Medium Business Customers

SMB customers were first recruited by telephone to ensure that Nexant identified the appropriate individuals for answering questions related to energy and outage issues for that company; and to secure a verbal agreement from them to complete the survey. Telephone interviewers explained the purpose of the survey and indicated that an incentive was to be provided to thank the respondent for their time. The individuals were then sent an email containing an individualized survey link or had the survey package mailed or faxed to them containing:

- Additional explanation of the purpose of the research;
- Clear and easy-to-understand instructions for completing the survey questions;
- A telephone number they could call if they had questions about the research or wished to verify its authenticity;
- The survey booklet (or a link in the email to compete the survey online); and
- Return envelope with pre-paid postage (for the paper survey option).

One week after the survey link was emailed or the survey was faxed, respondents were given a reminder call. Customers who requested regular mail received their reminder calls after approximately two weeks. About ten days after the reminder calls were made to the email recipients, the email was re-sent to anyone who had not yet completed the survey. If the survey was still not completed within ten days, it was assumed that the customer would not complete the survey and they were not contacted again. An incentive of $50 was mailed to respondents who completed the survey form.

The recruitment effort for the initial sample of 3,200 customers did not yield the response rate normally seen with SMB customers for VOS studies. To boost the number of responses, Nexant obtained authorization from THESL to increase incentives from $50 to $100. It also drew an additional sample of 3,200 SMB customers to raise the total sample to 6,400. The response rate increased modestly from initial levels, but remained low compared to previous studies—as only 245 customers completed and submitted surveys out of a target of 800.

3.3.3 Large C&I Customers

For large C&I customers, an experienced telephone recruiter first located and recruited an appropriate representative at each of the sampled premises with the assistance of THESL. The target respondent was usually a plant manager or plant engineering manager – someone who was familiar with the cost structure of the enterprise. Once the target respondent was identified and agreed to participate, the scheduler set up an appointment with the field interviewer. Once the appointment was scheduled, Nexant emailed the customer a confirmation along with a written description of the study and an explanation of the information they would be asked to provide. The interview was scheduled at the convenience of the customer. A financial incentive of $150 was offered for completion of the information. On the agreed upon date, Nexant's field interviewer visited the sampled site and conducted the in-person interview.

4 Outage Cost Estimation Methodology

4.1 Outage cost metrics

The results sections for each customer class (Sections 5 through 7) primarily focus on the following five outage cost metrics:

- Cost per Outage Event
- Cost per Average kW
- Cost per Unserved kWh
- Duration Cost per Outage Event
- Duration Cost per Average kW
- Duration Cost per Unserved kWh

Before presenting the results, it is important to understand how each of these metrics was derived. This section begins with a description of the cost per outage event estimate, as it came directly from the survey responses and the other cost metrics were derived from this one.

Cost per outage event is the average cost per customer resulting from each outage duration. It was derived by calculating a weighted average of the values that the respondent provided on the survey. Each scenario on the survey focused on a specific outage event and then asked the respondent to provide the cost estimate. The respondent was essentially providing the cost per outage event estimate. Before calculating the weighted average of these estimates, the top 0.5% of values normalized by usage was dropped from the analysis for residential and SMB. These outliers were dropped because respondents may erroneously provide unrealistically high estimates when taking an outage cost survey, as a result of human error or misunderstanding of the question. This step was skipped for large C&I customers as trained interviewers were walking customers through the questions. In addition, for residential customers, answers were considered outliers when the respondent selected the maximum $100 WTP response for all of the six scenarios (25 respondents). This set of responses suggested that the respondent was not carefully considering the outage scenario. After dropping outliers, cost per outage event was derived as an average of the customer responses, weighted by usage category for each segment.

Cost per average kW is the average cost per outage event normalized by average customer demand. This metric is useful for comparing outage costs across segments because it is normalized by customer demand. Cost per average kW was derived by dividing average cost per outage event by the weighted average customer demand among respondents for each outage duration by customer class. It is a ratio of the average values as opposed to the average of the ratios for each customer. Therefore, for each outage duration and customer class, average cost per event was first calculated using the steps above and then divided by the average demand among respondents. The average demand for each respondent was calculated as the annual kWh usage divided by 8,760 hours in the year, as shown in the following equation:

$$Average\ Demand = \left(\frac{Annual\ kWh\ usage}{8{,}760}\right)$$

As in the cost per outage event average calculation, the average customer demand (the denominator of the ratio) was weighted by usage category for each segment.

Cost per unserved kWh is the cost per outage event normalized by the expected amount of unserved kWh. This metric is useful because it can be readily used in planning applications, for which the amount of unserved kWh as a result of a given outage is commonly available. As in the cost per average kW calculation, cost per unserved kWh is a ratio of the average values as opposed to the average of the ratios for each customer. Therefore, for each duration and customer class, average cost per event was first calculated using the steps above and then divided by the expected unserved kWh. The expected unserved kWh is the estimated quantity of electricity that would have been consumed if an outage had not occurred.

Duration cost per outage event is the cost per outage event minus the cost for a momentary, 1-minute outage. The duration cost for a 1-minute outage is thus always $0. The other two duration cost metrics—duration cost per average kW and duration cost per unserved kWh—are calculated as described above, but with the adjusted event cost.

4.2 Special Considerations

Master metered customers: A number of large C&I customers were master metered, or bulk metered, meaning that one meter would serve the property owner, but that the building was occupied by multiple tenants. These tenants may or may not be sub-metered by a third party so that the property owner could bill them for electricity. THESL did not have contact information or consumption data for the tenants, as it did not directly meter the tenants. However, outage costs were incurred by the tenants. Interruption costs for master metered buildings were calculated by adding the outage costs for the property owner/manager with an estimate of the costs borne by the tenants. Tenant costs were estimated using either SMB or residential (depending on the type of tenant) cost per unserved kWh estimates and scaling them to the consumption level for the entire building.

Weekend/weekday differences: The outage scenarios in the survey instrument were designed to facilitate modeling seasonal differences in outage costs. Customers can only process a limited number of hypothetical scenarios before they get survey fatigue and introduce bias into the results. Therefore, all scenarios were for weekdays and the weekday/weekend differences for a recent interruption cost study for PG&E were used to adjust the estimates for this study for residential and SMB customers (but not for large C&I). The adjustments assume that interruptions are spread evenly across days of the week, such that weekend outage costs would be weighted by 2/7 and weekday costs by 5/7. The weekend adjustments for each time of day are shown below in Table 4.1.

Table 4-1:
Weekend Outage Cost Adjustments – Based on 2012 PG&E Study

Time of Day	Weekend Adjustment	
	Residential	SMB
Morning (7 AM to 11 AM)	-8%	-60%
Afternoon (12 PM to 5 PM)	-1%	-37%
Evening (6 PM to 9 PM)	20%	-61%
Night (10 PM to 6 AM)	4%	-58%

5 Residential Results

This section summarizes the results for residential customers.

5.1 Response to Survey

Table 5-1 summarizes the survey response for residential customers. With 1,061 total completed surveys, customer response was above the overall sample design target of 800. Overall, the survey had a 39.8% response rate that varied across usage categories. The second lowest usage category—with average kW of 0.25 to 0.57—had the highest response rate at 44 percent. The third usage category (0.57 to 1.1kW average) had nearly a 41 percent response rate. In the highest and lowest usage categories, the response rate was just over 37 percent. However, non-response bias among high and low usage residential customers is not a significant concern for the outage cost estimates because usage category is factored into the stratification weights in the analysis.

Table 5-1:
Customer Survey Response Summary – Residential

Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
0 to 0.25	62,103	204	681	255	37.4%
0.25 to 0.57	194,060	196	653	287	44.0%
0.57 to 1.1	252,994	191	638	260	40.8%
1.1 and above	145,816	208	694	259	37.3%
All	**654,973**	**800**	**2,666**	**1,061**	**39.8%**

Before presenting the outage cost estimates, it is important to summarize the prevalence of invalid responses. This summary is only provided for the residential segment because its cost estimates are derived from a WTP question. Some respondents are confused by WTP questions or end up answering a question that is quite different from the one that is being asked. For example, customers sometimes react to questions about WTP by redefining the question so that it relates to their satisfaction with service or whether they think they are being fairly charged for the service they are receiving. Such "protest responses" do not accurately reflect the cost of an outage for a customer, so they were removed from the analysis.

To identify these protest responses, the survey included a follow-up question for respondents that indicated a WTP value of $0. If the respondent verified that WTP was $0 because the outage scenario would not in fact result in any noticeable costs, the $0 response was confirmed as valid and included in the cost estimate calculations. However, if the respondent indicated that WTP was $0 because they thought it was unfair to pay more for electric service, the response was deemed invalid and not included in the cost estimate calculations. Table 5-2 summarizes the prevalence of invalid responses by outage duration in the residential survey.

The percentage of responses deemed invalid varied from 5.1% for a 24-hour outage to 6.0% for a 4-hour outage. The residential interruption cost estimates are based on the number of responses indicated in the "Valid Responses" category, which is fewer than what would normally be expected from a study with 1,061 responses. Note that the number of responses for the 4-hour outage duration was double those of other durations, as two of the six scenarios had 4-hour hypothetical outages.

Table 5-2:
Summary of Invalid Responses – Residential

Outage Duration	Total Responses	Invalid Responses		Valid Responses
		N	%	
1 minute	1,061	55	5.2%	1006
1 hour	1,061	56	5.3%	1005
4 hours	2,122	127	6.0%	1,995
8 hours	1,061	56	5.3%	1005
24 hours	1,061	54	5.1%	1007

5.2 Outage Cost Estimates

Figure 5-1 and Table 5-3 provide the residential cost per outage event estimates by region. For a 1-hour outage, residential customers experience a cost of $10.87 on average across the entire service territory. Cost per outage event increases to $23.35 at 8 hours and $34.53 for a 24-hour outage. Residents of York and North York generally report higher interruption costs, while residents of East York and Scarborough report lower costs. For a 1-hour interruption, Costs range from $8.55 to $13.39 for a 1-hour outage, $13.04 to $23.10 for a 4-hour outage, $17.55 to $27.12 for an 8-hour outage and $21.09 to $44.47 for a 24-hour outage. The percentage difference between regions increases with duration, suggesting that outages have a relatively higher incremental impact in North York as duration increases. However, it should be noted that East York and York both have small sample sizes. This means that the standard errors are larger and the confidence bands are wider. The small sample size could also partially account for the unusual result for York of a 1-hour outage valued slightly less than a 1-minute outage. There is a difference in the point estimates between the two durations but the confidence bands are overlapping.

Figure 5-1:
Cost per Outage Event Estimates by Region – Residential

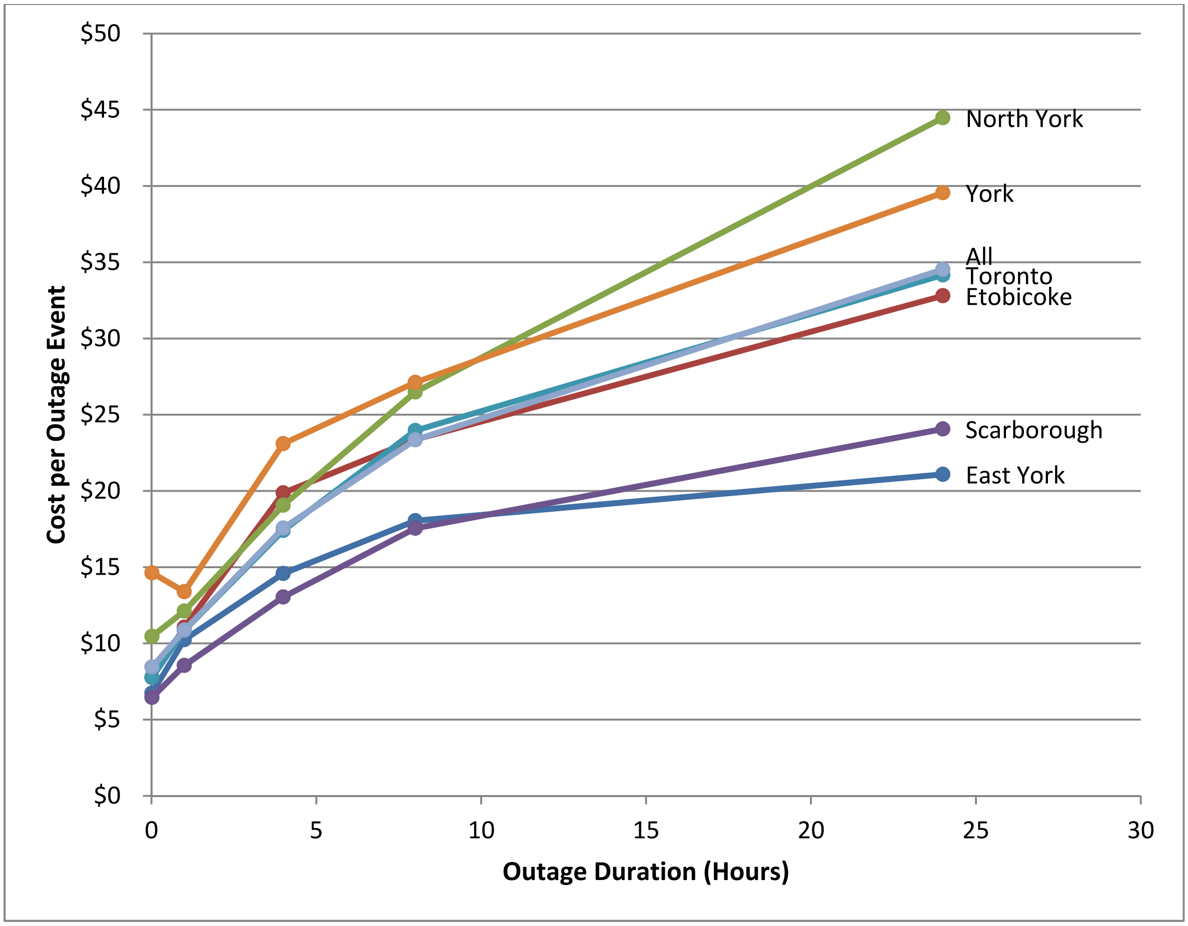


Table 5-4 summarizes residential cost per average kW. For a 1-hour outage, residential customers experience a cost of $13.21 per average kW. The cost per average kW estimates are roughly 20% higher than the cost per outage event estimates because average demand for residential respondents was around 0.8 kW. Scarborough and East York are again at the lower end of the cost range between regions. Costs range from$ 7.79 to $18.59 for a one-minute outage, $10.32 to $16.99 for a 1-hour outage, $15.77 to $29.33 for a 4-hour outage, $20.92 to $34.47 for an 8-hour outage and $26.86 to $50.31 for a 24-hour outage.

Table 5-5 provides the residential cost per unserved kWh estimates. For a 1-hour outage, residential customers experience a cost of $13.21 per unserved kWh, which is equivalent to the cost per average kW estimate because the expected amount of unserved kWh is also around 0.8 at 1 hour. For a 1-minute outage, the system-wide cost estimate is over $616 because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. As duration increases, cost per unserved kWh decreases steeply because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate.

Table 5-3:
2018 Cost per Outage Event Estimates by Region – Residential

Region	Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
				Lower Bound	Upper Bound
East York	1 minute	29	$6.74	$2.77	$10.71
	1 hour	28	$10.24	$5.49	$14.99
	4 hours	55	$14.58	$10.25	$18.92
	8 hours	28	$18.04	$10.53	$25.54
	24 hours	28	$21.09	$11.75	$30.44
Etobicoke	1 minute	130	$7.76	$5.40	$10.12
	1 hour	132	$11.06	$7.89	$14.23
	4 hours	261	$19.87	$16.40	$23.35
	8 hours	130	$23.37	$16.17	$30.58
	24 hours	132	$32.80	$20.81	$44.79
North York	1 minute	224	$10.46	$8.12	$12.80
	1 hour	222	$12.12	$9.71	$14.53
	4 hours	447	$19.06	$16.41	$21.71
	8 hours	224	$26.49	$18.79	$34.18
	24 hours	223	$44.47	$28.35	$60.58
Scarborough	1 minute	150	$6.45	$4.67	$8.23
	1 hour	150	$8.55	$6.59	$10.52
	4 hours	290	$13.04	$11.27	$14.81
	8 hours	145	$17.55	$14.23	$20.88
	24 hours	146	$24.06	$19.89	$28.23
Toronto	1 minute	397	$7.76	$5.63	$9.89
	1 hour	397	$10.85	$9.02	$12.67
	4 hours	790	$17.40	$15.11	$19.68
	8 hours	402	$23.96	$19.35	$28.56
	24 hours	402	$34.16	$29.04	$39.28
York	1 minute	42	$14.62	$6.67	$22.57
	1 hour	42	$13.39	$7.88	$18.90
	4 hours	84	$23.10	$17.20	$29.00
	8 hours	42	$27.12	$18.97	$35.26
	24 hours	42	$39.56	$26.42	$52.69
All	**1 minute**	**972**	**$8.45**	**$7.31**	**$9.58**
	1 hour	**971**	**$10.87**	**$9.78**	**$11.96**
	4 hours	**1927**	**$17.56**	**$16.32**	**$18.81**
	8 hours	**971**	**$23.35**	**$20.53**	**$26.17**
	24 hours	**973**	**$34.53**	**$29.80**	**$39.27**

Table 5-4:
2018 Cost per Average kW Estimates by Region – Residential

Region	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
East York	1 minute	29	$8.39	$2.72	$14.06
	1 hour	28	$13.02	$6.19	$19.85
	4 hours	55	$18.72	$12.44	$25.00
	8 hours	28	$22.97	$12.66	$33.28
	24 hours	28	$26.86	$14.33	$39.40
Etobicoke	1 minute	130	$9.74	$6.72	$12.76
	1 hour	132	$13.89	$9.95	$17.84
	4 hours	261	$25.15	$20.84	$29.46
	8 hours	130	$29.52	$20.61	$38.43
	24 hours	132	$41.43	$26.55	$56.31
North York	1 minute	224	$10.86	$8.36	$13.36
	1 hour	222	$12.55	$9.91	$15.20
	4 hours	447	$19.73	$16.85	$22.62
	8 hours	224	$27.53	$19.60	$35.47
	24 hours	223	$46.12	$29.52	$62.72
Scarborough	1 minute	150	$7.79	$5.62	$9.95
	1 hour	150	$10.32	$7.90	$12.73
	4 hours	290	$15.77	$13.59	$17.94
	8 hours	145	$20.92	$16.97	$24.88
	24 hours	146	$28.76	$23.67	$33.84
Toronto	1 minute	397	$10.43	$7.47	$13.39
	1 hour	397	$14.57	$12.02	$17.11
	4 hours	790	$23.32	$20.16	$26.48
	8 hours	402	$32.30	$25.95	$38.64
	24 hours	402	$46.07	$38.90	$53.24
York	1 minute	42	$18.59	$8.09	$29.10
	1 hour	42	$16.99	$9.35	$24.64
	4 hours	84	$29.33	$20.93	$37.73
	8 hours	42	$34.47	$22.05	$46.90
	24 hours	42	$50.31	$30.56	$70.06
All	**1 minute**	**972**	**$10.27**	**$8.85**	**$11.69**
	1 hour	**971**	**$13.21**	**$11.84**	**$14.58**
	4 hours	**1927**	**$21.36**	**$19.79**	**$22.92**
	8 hours	**971**	**$28.41**	**$24.98**	**$31.85**
	24 hours	**973**	**$42.04**	**$36.28**	**$47.79**

Table 5-5:
2018 Cost per Unserved kWh Estimates by Region – Residential

Region	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
East York	1 minute	29	$503.52	$163.28	$843.75
	1 hour	28	$13.02	$6.19	$19.85
	4 hours	55	$4.68	$3.11	$6.25
	8 hours	28	$2.87	$1.58	$4.16
	24 hours	28	$1.12	$0.60	$1.64
Etobicoke	1 minute	130	$584.25	$402.91	$765.60
	1 hour	132	$13.89	$9.95	$17.84
	4 hours	261	$6.29	$5.21	$7.36
	8 hours	130	$3.69	$2.58	$4.80
	24 hours	132	$1.73	$1.11	$2.35
North York	1 minute	224	$651.50	$501.36	$801.64
	1 hour	222	$12.55	$9.91	$15.20
	4 hours	447	$4.93	$4.21	$5.65
	8 hours	224	$3.44	$2.45	$4.43
	24 hours	223	$1.92	$1.23	$2.61
Scarborough	1 minute	150	$467.11	$337.12	$597.11
	1 hour	150	$10.32	$7.90	$12.73
	4 hours	290	$3.94	$3.40	$4.49
	8 hours	145	$2.62	$2.12	$3.11
	24 hours	146	$1.20	$0.99	$1.41
Toronto	1 minute	397	$625.61	$447.93	$803.30
	1 hour	397	$14.57	$12.02	$17.11
	4 hours	790	$5.83	$5.04	$6.62
	8 hours	402	$4.04	$3.24	$4.83
	24 hours	402	$1.92	$1.62	$2.22
York	1 minute	42	$1,115.60	$485.23	$1,745.97
	1 hour	42	$16.99	$9.35	$24.64
	4 hours	84	$7.33	$5.23	$9.43
	8 hours	42	$4.31	$2.76	$5.86
	24 hours	42	$2.10	$1.27	$2.92
All	**1 minute**	**972**	**$616.11**	**$531.06**	**$701.17**
	1 hour	**971**	**$13.21**	**$11.84**	**$14.58**
	4 hours	**1927**	**$5.34**	**$4.95**	**$5.73**
	8 hours	**971**	**$3.55**	**$3.12**	**$3.98**
	24 hours	**973**	**$1.75**	**$1.51**	**$1.99**

Table 5-6 shows duration cost, duration cost per average kW, and duration cost per unserved kWh by region and overall. Duration cost is the event cost minus the event cost for a 1-minute outage. It represents the event cost beyond the momentary interruption. Thus, the duration cost for a one-minute outage is $0. The duration cost per unserved kWh is a similar calculation to Table 5-5, but it divides the duration cost—instead of event cost—by unserved kWh.

Table 5-6:
2018 Duration Cost Estimates by Region – Residential

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
East York	1 minute	29	$0.00	$0.00	$0.00
	1 hour	28	$3.50	$4.36	$4.45
	4 hours	55	$7.84	$9.76	$2.52
	8 hours	28	$11.30	$14.07	$1.80
	24 hours	28	$14.35	$17.87	$0.76
Etobicoke	1 minute	130	$0.00	$0.00	$0.00
	1 hour	132	$3.30	$4.14	$4.14
	4 hours	261	$12.11	$15.19	$3.83
	8 hours	130	$15.61	$19.59	$2.46
	24 hours	132	$25.04	$31.41	$1.32
North York	1 minute	224	$0.00	$0.00	$0.00
	1 hour	222	$1.66	$1.72	$1.72
	4 hours	447	$8.60	$8.93	$2.23
	8 hours	224	$16.03	$16.64	$2.08
	24 hours	223	$34.01	$35.31	$1.47
Scarborough	1 minute	150	$0.00	$0.00	$0.00
	1 hour	150	$2.11	$2.55	$2.54
	4 hours	290	$6.59	$7.96	$1.99
	8 hours	145	$11.11	$13.42	$1.66
	24 hours	146	$17.61	$21.27	$0.88
Toronto	1 minute	397	$0.00	$0.00	$0.00
	1 hour	397	$3.09	$4.15	$4.15
	4 hours	790	$9.64	$12.95	$3.23
	8 hours	402	$16.20	$21.76	$2.73
	24 hours	402	$26.40	$35.47	$1.48
York	1 minute	42	$0.00	$0.00	$0.00
	1 hour	42	$0.00	$0.00	$0.00
	4 hours	84	$8.48	$10.78	$2.69
	8 hours	42	$12.50	$15.89	$1.99
	24 hours	42	$24.94	$31.71	$1.32

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
All	1 minute	972	$0.00	$0.00	$0.00
	1 hour	971	$2.42	$2.94	$2.94
	4 hours	1927	$9.11	$11.08	$2.77
	8 hours	971	$14.90	$18.11	$2.27
	24 hours	973	$26.09	$31.71	$1.32

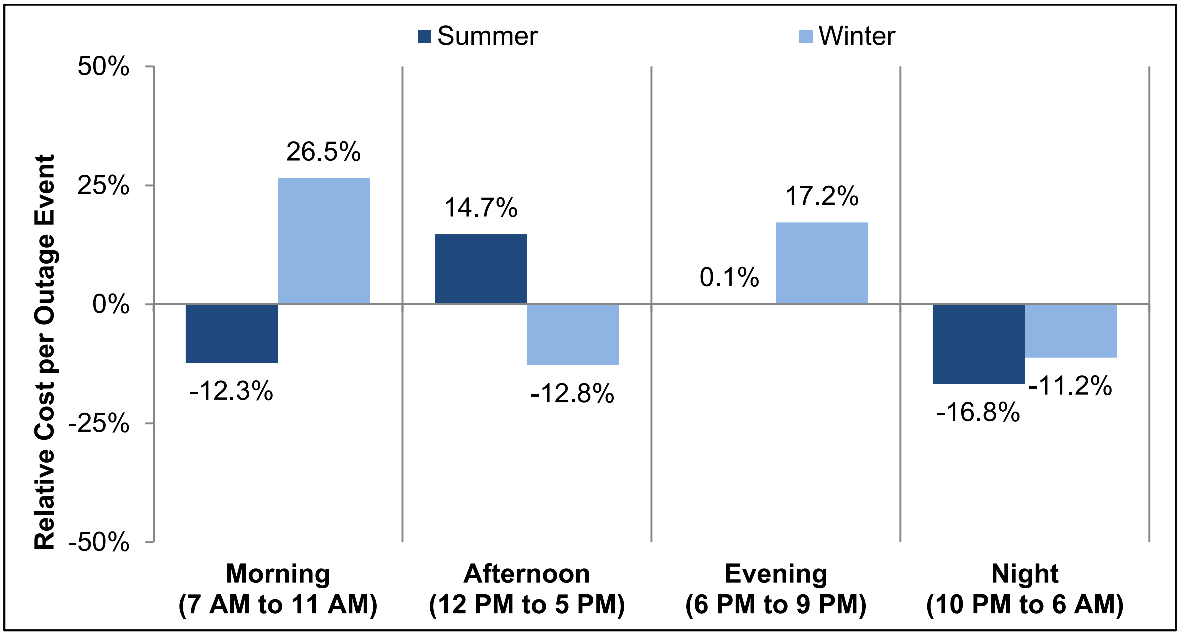
5.3 Impact of Outage Timing

For the residential analysis on the impact of outage timing, onset times were aggregated into 4 key time periods with distinct cost per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

Figure 5-2 provides the relative cost per outage event estimates, which were derived from the residential customer damage functions described in Appendix A. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each residential outage cost estimate in Section 5.2 (referred to as the "base value"). As shown in the figure, outage costs for residential customers are somewhat sensitive to onset time, varying from 16.8% lower than the base value on a summer night to 26.5% higher on a winter morning. Residential customers experience relatively high outage costs during winter mornings, winter evenings, and summer afternoons. These results could reflect the importance of home heating during winter mornings and evenings and home cooling during summer afternoons.

Figure 5-2:
Relative Cost per Outage Event Estimates by Season and Onset Time – Residential



5.4 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 5-3 and Table 5-7 shows the percent of residential customers rating each combination of outage frequency and duration as acceptable. As expected, a residential customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Residential customers are willing to accept a relatively high frequency of short-duration outages.

Figure 5-3:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable – Residential

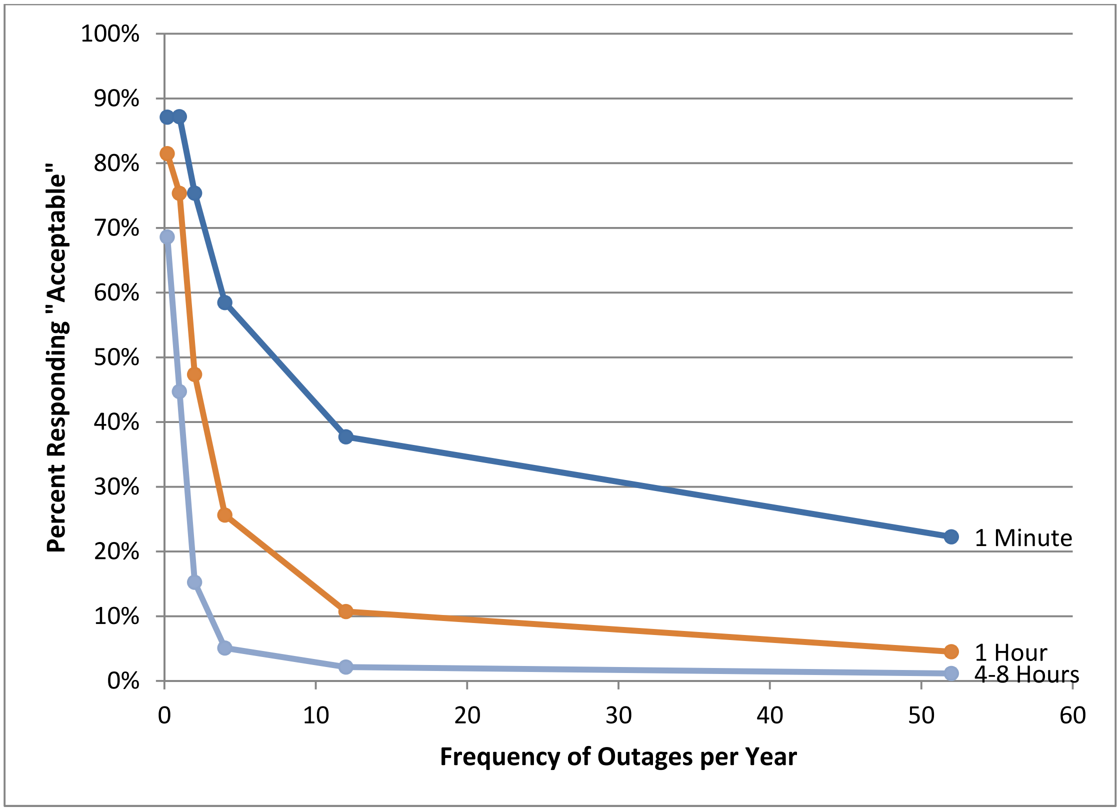


Table 5-7:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable – Residential

Region	Frequency of Outages per Year	Outage Duration		
		1 Minute	1 Hour	4-8 Hours
All	Once every 5 years	87.1%	81.5%	68.6%
	1	87.2%	75.3%	44.7%
	2	75.4%	47.4%	15.3%
	4	58.5%	25.6%	5.1%
	12	37.7%	10.7%	2.1%
	52	22.3%	4.5%	1.2%

Table 5-8 shows two measures of satisfaction with service reliability. On a 5-point scale, with 1 as “Very Low” and 5 as “Very High,” residential customers report a 1.84 average rating for the number of power outages they experience. On a 5-point scale, with 1 as “Very Dissatisfied” and 5 as “Very Satisfied,” residential customers report a 4.05 average rating of their satisfaction with the level of service reliability they receive from THESL.

Table 5-8:
Satisfaction with Service Reliability – Residential

Question	Average Score
Do you feel the number of power outages your residence experiences is … (5-point scale, 1 for “Very Low” to 5 for “Very High”)	1.84
How satisfied are you with the reliability of the electrical service you receive from Toronto Hydro? (5-point scale, 1 for “Very Dissatisfied" to 5 for “Very Satisfied”)	4.05

6 Small & Medium Business Results

This section summarizes the results for SMB customers.

6.1 Response to Survey

Table 6-1 summarizes the survey response for SMB customers. With 245 total completed surveys, customer response was below the overall sample design target of 800. The study results are valid, but obtaining results by smaller geographic regions within the service territory (as with residential customers) was not feasible and the confidence bands are wider than they otherwise would have been if the targets had been reached. The original sample design had a sample draw of 3,200 customers for an expected response rate of 25 percent. Once the customers in the first sample draw had been contacted and it was clear that the response rate was below target, Nexant worked with THESL to boost responses by increasing incentives from $50 to $100 and adding 3,200 customers to the sample. Even with the increased incentives, the response rate remained low. It was similar across the four usage categories, ranging only from 3.5 percent to 4.2 percent.

Table 6-1:
Customer Survey Response Summary – SMB

Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
0 to 1.35	14,668	204	1,638	62	3.7%
1.35 to 4.78	22,380	196	1,612	68	4.2%
4.78 to 25.8	17,499	191	1,620	56	3.5%
25.8 and above	9,146	208	1,530	59	3.8%
All	**63,693**	**800**	**6,400**	**245**	**3.8%**

6.2 Outage Cost Estimates

Figure 6-1 and Table 6-2 provide the SMB cost per outage event estimates. For a 1-hour outage, SMB customers experience a cost of $857.84. SMB cost per outage event increases to $4,098 at 8 hours and $8,426 for a 24-hour outage. Results for SMB customers are not broken down by region, as the number of completed surveys was too small to obtain meaningful results for the pre-amalgamation municipalities.

**Figure 6-1:
Cost per Outage Event Estimates – SMB**

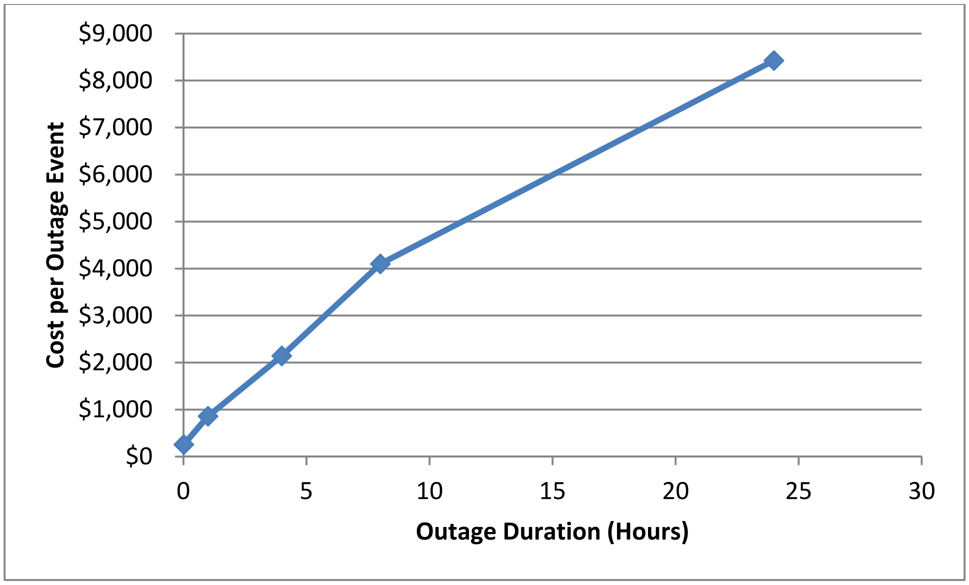


**Table 6-2:
Cost per Outage Event Estimates– SMB**

Region	Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	242	$257.38	$161.82	$352.95
	1 hour	242	$857.84	$611.74	$1,103.94
	4 hours	477	$2,142.39	$1,779.13	$2,505.66
	8 hours	240	$4,098.01	$2,844.42	$5,351.59
	24 hours	239	$8,426.27	$5,892.16	$10,960.38

Table 6-3 summarizes SMB cost per average kW. For a 1-hour outage, SMB customers experience a cost of $40.68 per average kW. The cost per average kW estimates are substantially lower than the cost per outage event estimates because average demand for SMB respondents was around 21 kW. Table 6-4 provides the SMB cost per unserved kWh estimates. For a 1-hour outage, SMB customers experience a cost of $40.68 per unserved kWh – same as the cost per average kW estimate. At 1-minute, the system-wide estimate is over $722, as the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. For a 24-hour outage, cost per unserved kWh is $16.64.

Table 6-3:
Cost per Average kW Estimates – SMB

Region	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	242	$12.04	$6.88	$17.20
	1 hour	242	$40.68	$26.20	$55.15
	4 hours	477	$98.29	$77.21	$119.37
	8 hours	240	$184.57	$131.62	$237.52
	24 hours	239	$399.42	$259.59	$539.25

Table 6-4:
Cost per Unserved kWh Estimates – SMB

Region	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	242	$722.43	$413.09	$1,031.76
	1 hour	242	$40.68	$26.20	$55.15
	4 hours	477	$24.57	$19.30	$29.84
	8 hours	240	$23.07	$16.45	$29.69
	24 hours	239	$16.64	$10.82	$22.47

Table 6-5 shows the duration cost, duration cost per average kW, and duration cost per unserved kWh for SMB. The duration cost is $0 for a 1-minute outage for all three metrics. For outage event, the duration cost ranges from $600 for a 1-hour outage to $8,169 for a 24-hour outage. Duration cost per average kW ranges from $28.47 for a 1-hour outage to $382 for a 24-hour outage. Duration cost per unserved kWh ranges from $28.47 for a 1-hour outage to $16.13 for a 24-hour outage.

Table 6-5:
2018 Duration Cost Estimates – SMB

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
All	1 minute	242	$0.00	$0.00	$0.00
	1 hour	242	$600.46	$28.47	$28.47
	4 hours	477	$1,885.01	$88.18	$21.62
	8 hours	240	$3,840.62	$179.67	$21.62
	24 hours	239	$8,168.89	$382.14	$16.13

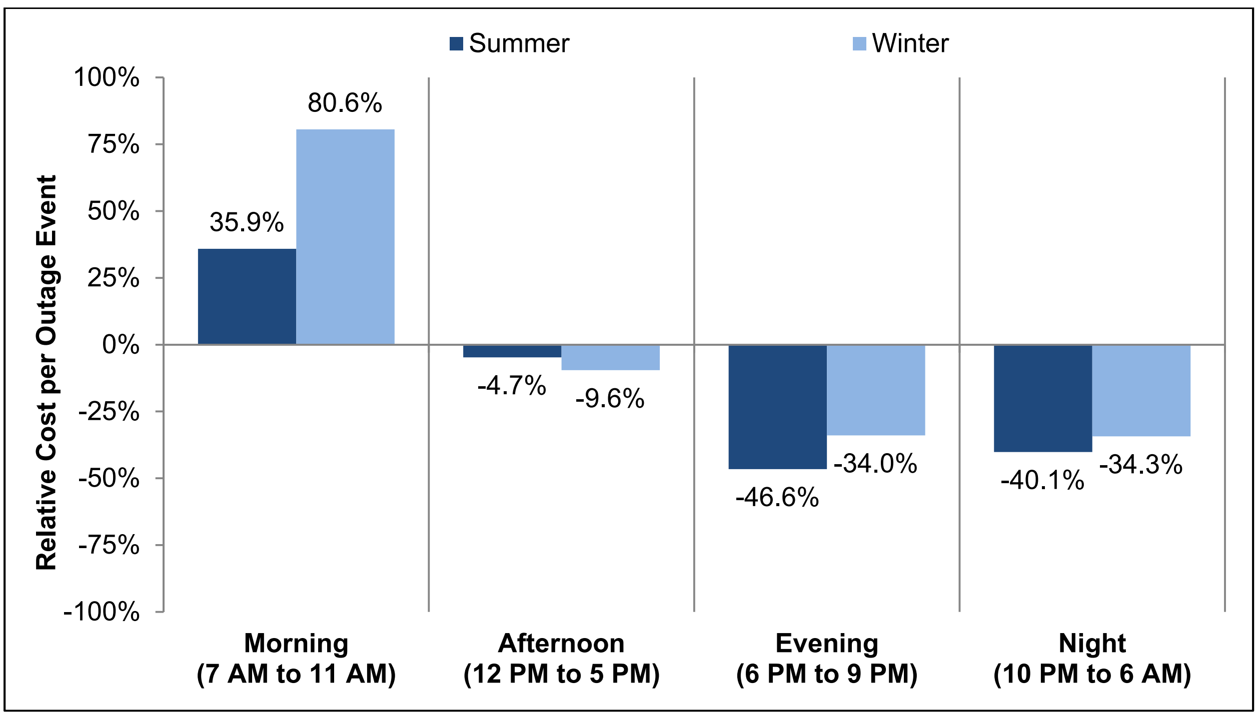
6.3 Impact of Outage Timing

For the residential analysis on the impact of outage timing, onset times were aggregated into 4 key time periods with distinct cost per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

Figure 6-2 provides the relative cost per outage event estimates, which were derived from the SMB customer damage functions described in Appendix A. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each SMB outage cost estimate in Section 6.2 (referred to as the "base value"). As shown in the figure, outage costs for SMB customers are highly sensitive to onset time, varying from 46.6% lower than the base value on a summer evening to 80.6% higher on a winter morning. Outages with a morning onset time have the highest cost because these outages likely start and end during normal business hours, potentially disrupting an entire day of work. Considering that SMB outage costs vary substantially depending on the onset time, it is important that planning applications apply these relative values.

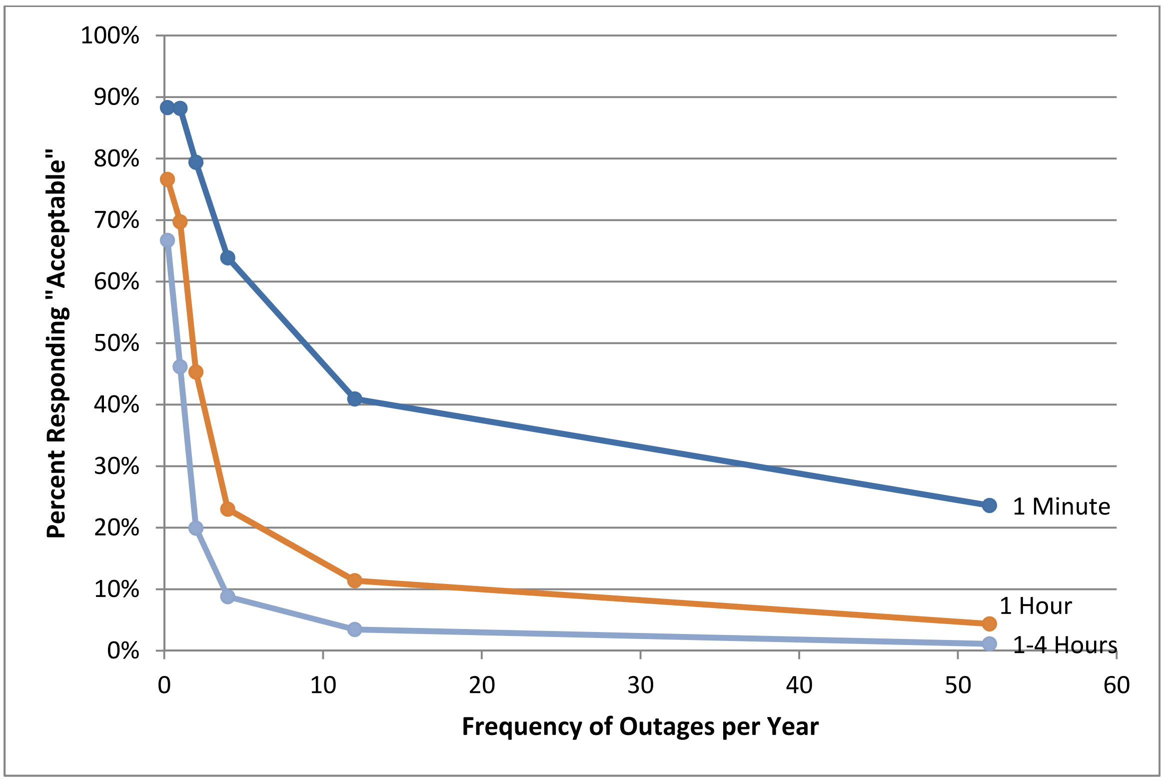
Figure 6-2:
Relative Cost per Outage Event Estimates by Season and Onset Time – SMB



6.4 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 6-3 and Table 6-6 show the percent of SMB customers rating each combination of outage frequency and duration as acceptable. As expected, an SMB customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. SMB customers are willing to accept a relatively high frequency of short-duration outages. A majority of SMB customers reports that 4 momentary outages per year is acceptable. One outage of 1 to 4 hours per year is acceptable to 46% of SMB customers, but four outages of this duration is acceptable to only 20 percent of customers.[6]

**Figure 6-3:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable – SMB**



[6] The longer-duration interruption for SMB was coded in the online survey as "1 to 4 hours" instead of "4 to 8 hours."

Table 6-6:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – SMB

Region	Frequency of Outages per Year	Outage Duration		
		1 Minute	1 Hour	1-4 Hours
All	Once every 5 years	88.3%	76.6%	66.7%
	1	88.2%	69.7%	46.2%
	2	79.4%	45.3%	19.9%
	4	63.9%	23.0%	8.8%
	12	40.9%	11.4%	3.5%
	52	23.6%	4.4%	1.1%

7 Large Business Results

This section summarizes the results for large business customers.

7.1 Response to Survey

Table 7-1 summarizes the survey response for large C&I customers. Nexant conducted onsite interviews covering 100 entity/service address combinations, which was the sample design target for this customer class. In some cases, all of the data needed for the outage cost estimates was not available at the interview—either because the interviewee did not have it readily available or was not willing to disclose it. In cases where the interviewee did not have it, Nexant attempted to follow up with the interview subject after the interview to obtain the missing data and calculate the outage cost estimate. This was successful for a number of large C&I customers. However, Nexant was not able to obtain the necessary data for 16 customers. The number of complete data points for large C&I was thus 84.

Table 7-1 shows a breakdown of the sample design by the three sample strata. Response rates were similar between strata, ranging from 28 percent to 33 percent.

Table 7-1:
Customer Survey Response Summary – Large C&I

Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Complete Data Points	Response Rate
235 to 911	158	27	74	24	32%
912 to 1934	189	31	83	23	28%
1935 and above	113	42	113	37	33%
All	**63,693**	**100**	**270**	**84**	**31%**

7.2 Outage Cost Estimates

Figure 7-1 and Table 7-2 provide the large business cost per outage event estimates. For a 1-hour outage, large business customers experience a cost of $71,808. Large business cost per outage event increases to $379,381 at 8 hours and $992,647 for a 24-hour outage. The confidence intervals for these estimates are quite wide, as the large C&I customer class had a smaller sample size and much more variable outage cost estimates from customer to customer

Figure 7-1:
Outage Event Estimates – Large C&I

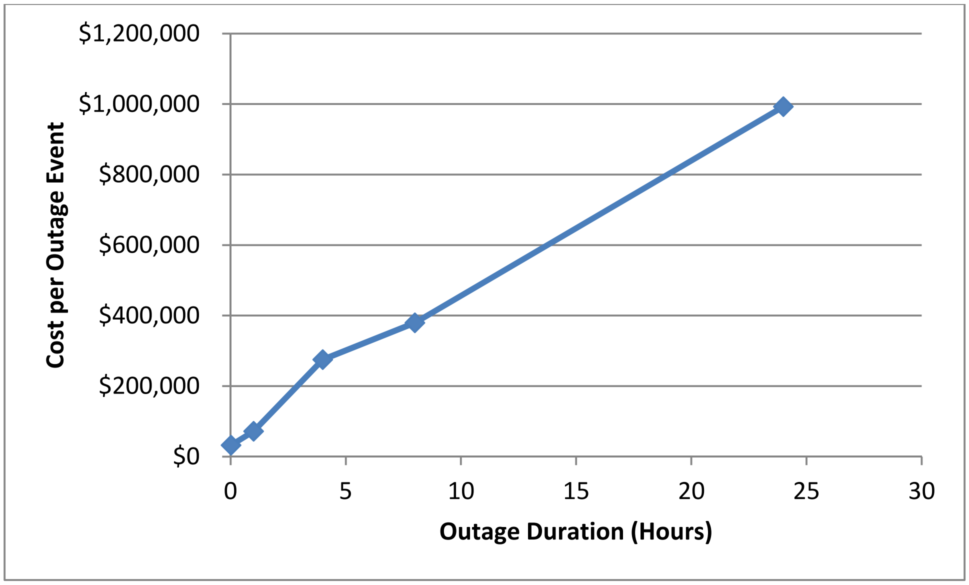


Table 7-2:
Cost per Outage Event Estimates – Large C&I

Region	Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	84	$32,438	$5,886	$58,990
	1 hour	84	$71,808	$30,636	$112,979
	4 hours	168	$275,182	$77,202	$473,162
	8 hours	84	$379,381	$120,328	$638,433
	24 hours	84	$992,647	$214,801	$1,770,493

Table 7-3 summarizes large business cost per average kW. The cost per average kW values range from $15.25 for a 1-minute outage to $467 for a 24-hour outage. Table 7-4 provides the cost per unserved kWh estimates. For a 1-minute outage, large C&I customers experience a cost of $915 per unserved kWh. For the remaining durations, cost estimates range from $19.45 to $33.77 per unserved kWh. Table 7-5 shows the duration cost metrics. These costs range from $39,369 to $960,209 for duration cost, from $18.51 to $452 for duration cost per average kW, and from $18.51 to $28.54 for duration cost per unserved kWh.

Table 7-3:
Cost per Average kW Estimates – Large C&I

Region	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	84	$15.25	$2.69	$27.82
	1 hour	84	$33.77	$13.62	$53.91
	4 hours	168	$129.41	$34.25	$224.57
	8 hours	84	$178.41	$51.42	$305.40
	24 hours	84	$466.81	$87.68	$845.95

Table 7-4:
Cost per Unserved kWh Estimates– Large C&I

Region	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	84	$915.28	$161.23	$1,669.34
	1 hour	84	$33.77	$13.62	$53.91
	4 hours	168	$32.35	$8.56	$56.14
	8 hours	84	$22.30	$6.43	$38.18
	24 hours	84	$19.45	$3.65	$35.25

Table 7-5:
2018 Duration Cost Estimates by Region – Large C&I

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
All	1 minute	84	$0.00	$0.00	$0.00
	1 hour	84	$39,369.44	$18.51	$18.51
	4 hours	168	$242,743.76	$114.16	$28.54
	8 hours	84	$346,942.45	$163.16	$20.39
	24 hours	84	$960,208.73	$451.56	$18.81

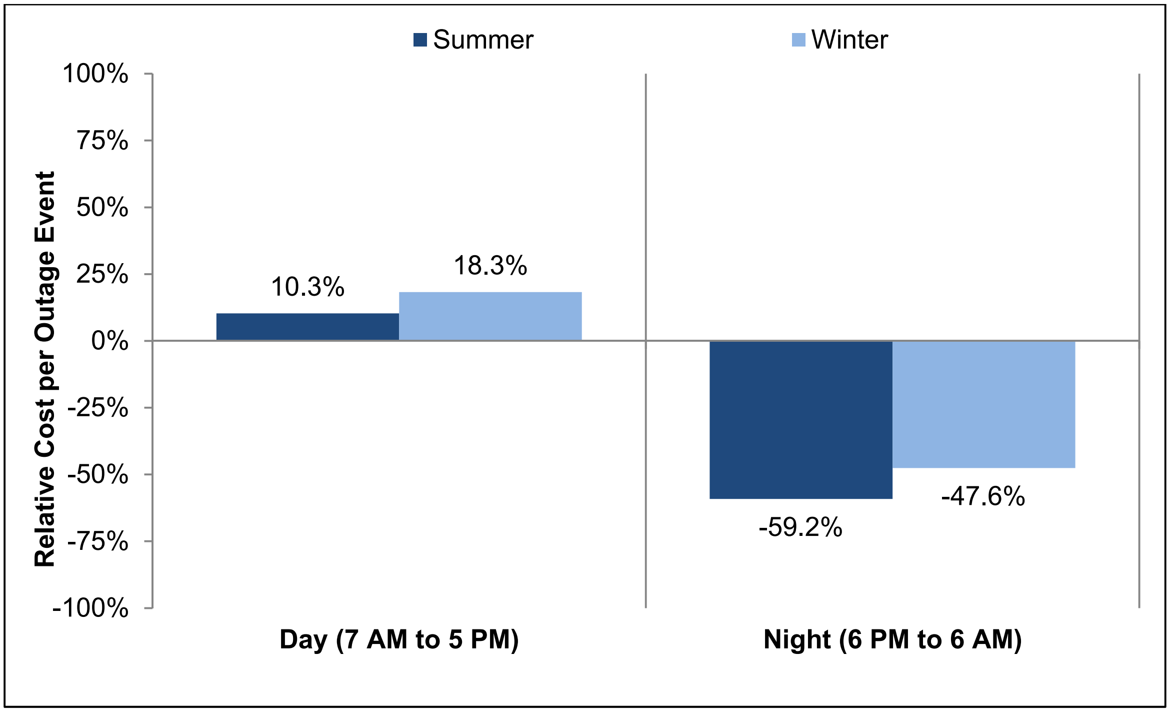
7.3 Impact of Outage Timing

For the large business analysis on the impact of outage timing, onset times were aggregated into 2 key time periods with distinct cost per outage event. These time periods were:

- Daylight Hours (7 AM to 5 PM); and
- Evening and Night (6 PM to 6 AM).

Figure 7-2 provides the relative cost per outage event estimates, which were derived from the large C&I customer damage functions described in Appendix A. Unlike the other 3 customer segments, the onset times were not further divided by day of week because this variable did not have a significant effect for large business customers. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each large business outage cost estimate in Section 7.2 (referred to as the "base value"). As shown in the figure, outage costs for large C&I customers are somewhat sensitive to onset time, varying moderately from 18.3% higher than the base value during daylight hours to 59.2% lower during the evening and night.

Figure 7-2:
Relative Cost per Outage Event Estimates by Season and Onset Time – Large C&I



7.4 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 7-3 and Table 7-6 show the percent of large business customers rating each combination of outage frequency and duration as acceptable. As expected, a large business customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. A single sustained outage more than 1 minute per year is considered unacceptable for a majority of large C&I customers. Four momentary outages is considered unacceptable by the majority.

Figure 7-3:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – Large C&I

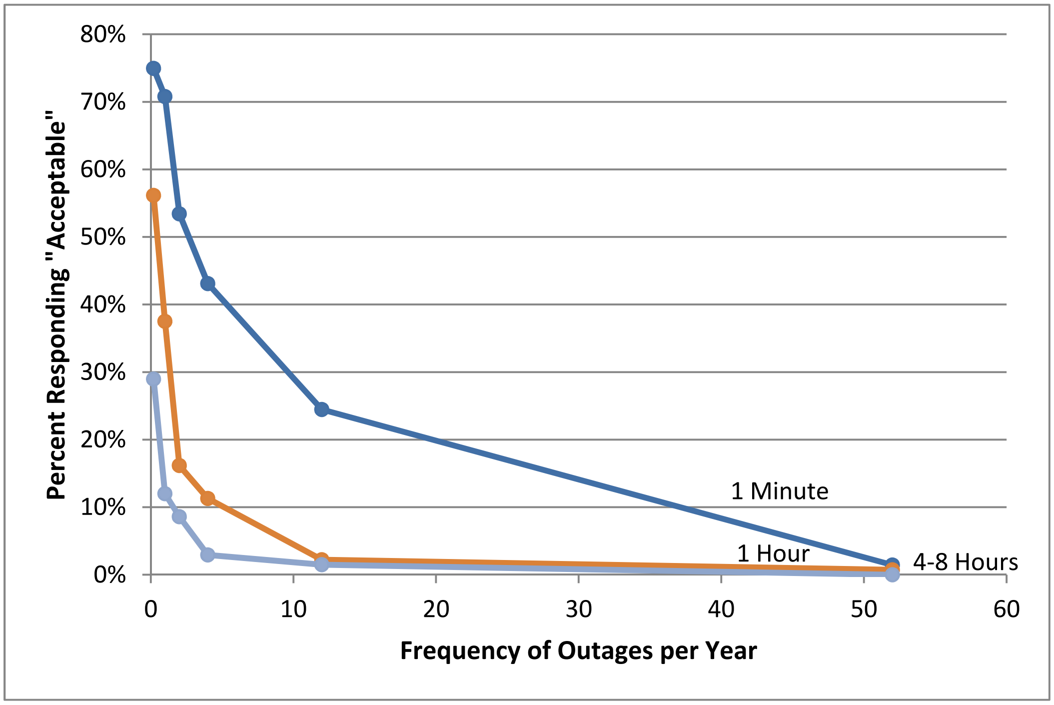


Table 7-6:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – Large C&I

Region	Frequency of Outages per Year	Outage Duration		
		1 Minute	1 Hour	4-8 Hours
All	Once every 5 years	87.1%	81.5%	68.6%
	1	87.2%	75.3%	44.7%
	2	75.4%	47.4%	15.3%
	4	58.5%	25.6%	5.1%
	12	37.7%	10.7%	2.1%
	52	22.3%	4.5%	1.2%

8 Blended Results

This section summarizes the blended results for all customers. Sampling was conducted on a per-customer basis and the outage costs were collected and aggregated on a per-customer basis. The blended estimate calculations utilize the weighted average of per-customer costs as well as the weighted average of per-customer usage in order to scale the costs by kWh. Given that costs and usage are significantly higher for non-residential customers (particularly large C&I), their responses increase both average cost and usage. Thus the blended 'cost per average kW' and 'cost per unserved kWh' estimates account for non-residential customers having higher consumption.

Table 8-1 shows the blended cost per outage event estimate for each outage duration. The third column from the left—labeled 'N'—shows the number of completed surveys from residential, SMB, and large C&I combined. The blended event costs range from $51.24 for a 1-minute outage to $1,413 for a 24-hour outage. Tables 8-2 ad 8-3 show the cost per average kW and cost per unserved kWh values, respectively. Blended cost per average kW values range from $12.80 for a 1-minute outage to $355 for a 24-hour outage. Blended cost per unserved kWh values range from $768 for a 1-minute outage to $14.80 for a 24-hour outage.

Table 8-1:
Cost per Outage Event Estimates – Blended Results

Region	Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	1298	$51.24	$31.95	$70.53
	1 hour	1297	$131.81	$95.71	$167.91
	4 hours	2572	$381.77	$247.75	$515.79
	8 hours	1295	$626.90	$418.09	$835.72
	24 hours	1296	$1,412.73	$844.74	$1,980.72

Table 8-2:
Cost per Average kW Estimates – Blended Results

Region	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	1298	$12.80	$7.90	$17.70
	1 hour	1297	$33.14	$23.79	$42.49
	4 hours	2572	$94.50	$61.22	$127.78
	8 hours	1295	$153.83	$105.24	$202.43
	24 hours	1296	$355.23	$212.48	$497.98

Table 8-3:
Cost per Unserved kWh Estimates – Blended Results

Region	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	1298	$768.06	$473.82	$1,062.30
	1 hour	1297	$33.14	$23.79	$42.49
	4 hours	2572	$23.63	$15.31	$31.95
	8 hours	1295	$19.23	$13.15	$25.30
	24 hours	1296	$14.80	$8.85	$20.75

Table 8-4 shows the blended duration cost, duration cost per average kW, and duration cost per unserved kWh. The blended duration cost is $0 for a 1-minute outage for all three metrics. For outage event, the blended duration cost ranges from $80.57 for a 1-hour outage to $1,361 for a 24-hour outage. Duration cost per average kW ranges from $20.26 for a 24-hour outage to $340 for a 24-hour outage. Duration cost per unserved kWh ranges from $14.26 for a 24-hour outage to $20.45 for a 4-hour outage.

Table 8-4:
2018 Duration Cost Estimates – Blended

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
All	1 minute	1298	$0.00	$0.00	$0.00
	1 hour	1297	$80.57	$20.26	$20.26
	4 hours	2572	$330.53	$82.57	$20.45
	8 hours	1295	$575.66	$143.81	$17.66
	24 hours	1296	$1,361.49	$340.13	$14.26

Toronto Hydro was seeking a single, per-hour cost based on historical outages and Table 1-6 provides these "blended duration costs." The table shows these figures for different types of outages in Toronto Hydro service territory from 2010 to 2017. The "Outages Included" column shows which types of outages were included in the blended cost. All outages were categorized by Toronto Hydro as either "Momentary," "Planned," or "Sustained." Given that the results of this study are only valid for outages lasting 24 hours or less, all outages greater than 24 hours were excluded from the calculations. Within each outage type, outages could also be classified as "Loss of Supply Events" or could have occurred on "Major Event Days." These subcategories of outages were either left in the dataset or excluded, depending on the calculation.

The "Event Cost" column shows the average event cost of the outages in the dataset, based on the blended estimates in Table 1-5 and weighted by the number of customers impacted by the outage. The "Duration Event Cost" column shows the weighted average duration event cost, which is the event cost minus the blended 1-minute event cost estimate of $51.24. The

"Duration" column shows the weighted average outage duration. The two "Hourly Cost" columns show each event cost per hour, or the "Event Cost" columns divided by the "Duration" column. Depending on the types of outages included, the weighted average duration ranges from 2.9 to 3.6 hours. The hourly event costs are within a relatively tight range, varying from $84.31 to $89.78, while the hourly duration event costs range from $69.94 to $71.87.

**Table 8-5:
Blended Duration Cost Based on Historical Outage Durations**

Outages Included*	Subset of Outages Excluded	Event Cost		Duration (Hours)	Hourly Cost	
		Event Cost	Duration Event Cost		Hourly Event Cost	Hourly Duration Event Cost
Sustained	-	$288.96	$237.72	3.39	$85.32	$70.19
Sustained	Loss of Supply Events	$300.72	$249.48	3.57	$84.31	$69.94
Sustained	Major Event Days	$256.56	$205.32	2.86	$89.60	$71.70
Sustained	Loss of Supply Events, Major Event Days	$272.70	$221.46	3.09	$88.23	$71.65
Sustained, Planned	-	$288.44	$237.20	3.37	$85.54	$70.34
Sustained, Planned	Loss of Supply Events	$299.77	$248.53	3.54	$84.57	$70.11
Sustained, Planned	Major Event Days	$256.81	$205.57	2.86	$89.78	$71.87
Sustained, Planned	Loss of Supply Events, Major Event Days	$272.50	$221.26	3.08	$88.45	$71.82

* Only includes outages up to 24 hours in duration

9 Comparison to Other Studies

Nexant (formerly as Freeman, Sullivan & Co.) has conducted dozens of VOS studies for utilities and also works with Lawrence Berkeley National Laboratory to maintain the Interruption Cost Estimation (ICE) Calculator and its underlying database of survey-based VOS studies. The results from most studies for individual utilities are not public, but relatively recent studies from PG&E (conducted in 2012) and SCE (conducted in 2019) have public results that are useful for comparison. For other non-public studies contained in the ICE Calculator database, the utility is not identifiable, but the data can be aggregated and compared to current results. The ICE Calculator meta-database contains the results from 34 studies that use a similar, survey-based methodology.

Tables 9-1, 9-2, and 9-3 show the outage cost estimates from the PG&E and SCE studies for the residential, small/medium business and large C&I customer classes respectively. The tables show the results after adjusting for inflation (3% annually) and the exchange rate between the U.S. dollar and Canadian dollar (1.29 $CAD per 1 $US). The 2012 study separated results between the Bay Area and Non-Bay Area for PG&E and the tables show both sets of results along with the estimates for the service territory as a whole. Bay Area outage cost estimates were considerably higher than outage costs for the Non-Bay Area, SCE, and THESL. Residential outage costs for THESL were comparable to those of the Non-Bay Area and SCE. Small/medium business outage costs for THESL are considerably lower than both PG&E and SCE for the cost per outage event, cost per average kW, and cost per unserved kWh. Large C&I outage cost per event estimates are comparable to the Non-Bay Area and to SCE. However, the cost per average kW and cost per unserved kWh estimates are lower, indicating higher consumption for THESL customers.

The shape of THESL's outage cost distributions are similar to those of PG&E, SCE, and other studies, but they are generally lower in magnitude. Looking specifically at the survey data from THESL and SCE, significant differences exist in the underlying populations for the two utilities, making comparisons of the interruption costs tenuous. For example, Toronto's non-residential customer population comprises different industry types and the customers had higher annual consumption than SCE. This suggests that interruption costs from areas other than Toronto should not be used to estimate THESL’s customer interruption costs.

Table 9-1:
Comparison to PG&E and SCE Studies – Residential

Metric	Outage Duration	PG&E (2012)			SCE (2019)	Toronto Hydro
		Bay Area	Non-Bay Area	All		
		$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD
Cost per Outage Event	1 minute	-	-	-	-	$8.45
	5 minutes	$12.60	$10.72	$11.41	$5.75	-
	1 hour	$20.36	$16.50	$18.31	$8.50	$10.87
	4 hours	$30.18	$22.94	$25.91	$16.49	$17.56
	8 hours	$41.02	$30.48	$35.26	$25.02	$23.35
	24 hours	$58.27	$40.09	$48.78	$41.22	$34.53
Cost per Average kW	1 minute	-	-	-	-	$10.27
	5 minutes	$18.27	$12.92	$15.02	$7.89	-
	1 hour	$28.68	$18.75	$22.89	$11.86	$13.21
	4 hours	$42.50	$25.48	$32.39	$22.18	$21.36
	8 hours	$57.78	$33.87	$44.07	$34.04	$28.41
	24 hours	$83.24	$45.56	$61.75	$56.73	$42.04
Cost per Unserved kWh	1 minute	-	-	-	-	$616.11
	5 minutes	$209.99	$153.15	$190.23	$94.70	-
	1 hour	$29.10	$18.13	$22.89	$11.86	$13.21
	4 hours	$10.37	$6.16	$7.82	$5.55	$5.34
	8 hours	$7.02	$4.08	$5.30	$4.26	$3.55
	24 hours	$3.45	$1.89	$2.57	$2.37	$1.75

Table 9-2:
Comparison to PG&E and SCE Studies – Small/Medium Business

Metric	Outage Duration	PG&E (2012)			SCE (2019)	Toronto Hydro
		Bay Area	Non-Bay Area	All		
		$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD
Cost per Outage Event	1 minute	-	-	-	-	$257
	5 minutes	$901	$245	$585	$670	-
	1 hour	$4,127	$1,500	$2,848	$3,881	$858
	4 hours	$10,178	$4,253	$7,354	$4,332	$2,142
	8 hours	$25,359	$6,831	$16,279	$5,825	$4,098
	24 hours	$52,034	$13,115	$32,870	$10,158	$8,426
Cost per Average kW	1 minute	-	-	-	-	$12
	5 minutes	$96	$30	$67	$86	-
	1 hour	$419	$188	$316	$541	$41
	4 hours	$1,087	$522	$832	$593	$98
	8 hours	$2,404	$859	$1,750	$857	$185
	24 hours	$5,364	$1,654	$3,702	$1,359	$399
Cost per Unserved kWh	1 minute	-	-	-	-	$722
	5 minutes	$1,099	$350	$760	$1,036	-
	1 hour	$403	$177	$301	$541	$41
	4 hours	$259	$122	$196	$148	$25
	8 hours	$296	$102	$213	$107	$23
	24 hours	$223	$69	$154	$57	$17

Table 9-3:
Comparison to PG&E and SCE Studies – Large Commercial & Industrial

Metric	Outage Duration	PG&E (2012)			SCE (2019)	Toronto Hydro
		Bay Area	Non-Bay Area	All		
		$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD
Cost per Outage Event	1 minute	-	-	-	-	$32,438
	5 minutes	$1,173,397	$37,442	$700,348	$22,164	-
	1 hour	$1,326,775	$84,672	$692,616	$100,281	$71,808
	4 hours	$1,653,916	$175,206	$919,075	$189,506	$275,182
	8 hours	$1,664,031	$227,018	$950,684	$301,139	$379,381
	24 hours	$3,469,269	$947,921	$2,268,128	$558,639	$992,647
Cost per Average kW	1 minute	-	-	-	-	$15
	5 minutes	$843	$26	$492	$27	-
	1 hour	$962	$63	$504	$98	$34
	4 hours	$1,193	$132	$673	$235	$129
	8 hours	$1,188	$170	$693	$370	$178
	24 hours	$2,562	$683	$1,613	$780	$467
Cost per Unserved kWh	1 minute	-	-	-	-	$915
	5 minutes	$9,991	$310	$5,807	$323	-
	1 hour	$939	$61	$491	$98	$34
	4 hours	$293	$33	$166	$59	$32
	8 hours	$146	$21	$86	$46	$22
	24 hours	$106	$28	$67	$32	$19

Table 9-4 shows the blended results from the ICE Calculator meta-database. The ICE Calculator inputs were customized to correspond to the same number of residential, small C&I (<50,000 annual kWh) and medium/large C&I (> 50,000 annual kWh) as in the current study. While customizing the database to a Canadian province was not an option, it was possible to customize to New York State, which borders Ontario. The results from the ICE Calculator in 2016 U.S. dollars are in column 3 and column 4 contains the ICE Calculator results adjusted for inflation and exchange rate. The results from the current study are in the right-most column. The ICE Calculator results are significantly higher than the results from the current study. The difference is driven by the results from the non-residential customer classes.

Table 9-4:
Comparison to ICE Calculator Meta-Data – Blended

Metric	Outage Duration	ICE Calculator	ICE Calculator	Toronto Hydro
		$2016 US	$2018 CAD	$2018 CAD
Cost per Outage Event	1 hour	$385.80	$527.99	$131.81
	4 hours	$906.26	$1,240.27	$381.77
	8 hours	$1,927.47	$2,637.86	$626.90
	24 hours	$1,727.42	$2,364.08	$1,412.73
Cost per Average kW	1 hour	$100.76	$137.89	$33.14
	4 hours	$236.68	$323.91	$94.50
	8 hours	$503.38	$688.91	$153.83
	24 hours	$451.14	$617.41	$355.23
Cost per Unserved kWh	1 hour	$100.76	$137.89	$33.14
	4 hours	$59.17	$80.98	$23.63
	8 hours	$62.92	$86.11	$19.23
	24 hours	$18.80	$25.73	$14.80

Appendix A Customer Damage Functions

This appendix details the customer damage functions, which are econometric models that predict how outage costs vary across customers, outage duration and other outage characteristics. For example, these models were used to develop the results in Sections 5 through 7 related to how outage costs vary by time of day and season for each customer class.

To model outage costs, Nexant used a two-part model. The two-part model first estimates the latent probability that customers experience an outage cost with a Probit model. Then, it estimates the outage costs for customers who reported values greater than zero with a Generalized Linear Model (GLM). The models were estimated with corrections to account for the structure of the survey data (i.e., clustering by customer, population weights and stratification). This approach was first used to model health care expenditures, which, like outage costs, follow a highly skewed distribution. Nexant applied this model to a meta-analysis of outage costs in studies prepared for Lawrence Berkeley National Laboratory in 2009[1] and 2015.[2]

Nexant employed out-of-sample testing to select and validate the best econometric model for each customer segment. Because the model coefficients were derived from a system-wide survey, Nexant used out-of-sample testing to ensure that the estimates were robust to a variety of conditions. For each customer segment, Nexant experimented with different model specifications and estimated each model while withholding 25% of the data from the regression. To select the final model, Nexant compared the out-of-sample predicted outage costs from each model with the reported outage costs.

A.1 Residential Customers

To predict outage costs for residential customers, Nexant estimated an econometric model for residential customers from the survey data. The analysis included variables that capture customer size, duration of the outage, season, and time of day that the outage occurs.

Table A-1 shows the variables included in the residential customer regression model and the estimated coefficients for each part of the model. The natural log of average kW usage captures the influence of customer size on reported outage costs while duration and duration squared capture the impact of outage duration on reported outage costs. The square of the duration variable is meant to capture the non-linear relationship between outage costs and duration. The coefficient on the usage variable is significant at the 1% level for the GLM model and the duration variables are significant at the 1% level for both models. Several of the outage timing variables are statistically significant for the Probit model. Most of the timing variables are

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[1] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

[2] Sullivan, M. J., Schellenberg, J. & Blundell, M. (2015). Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States, Berkeley, CA: Lawrence Berkeley National Laboratory.

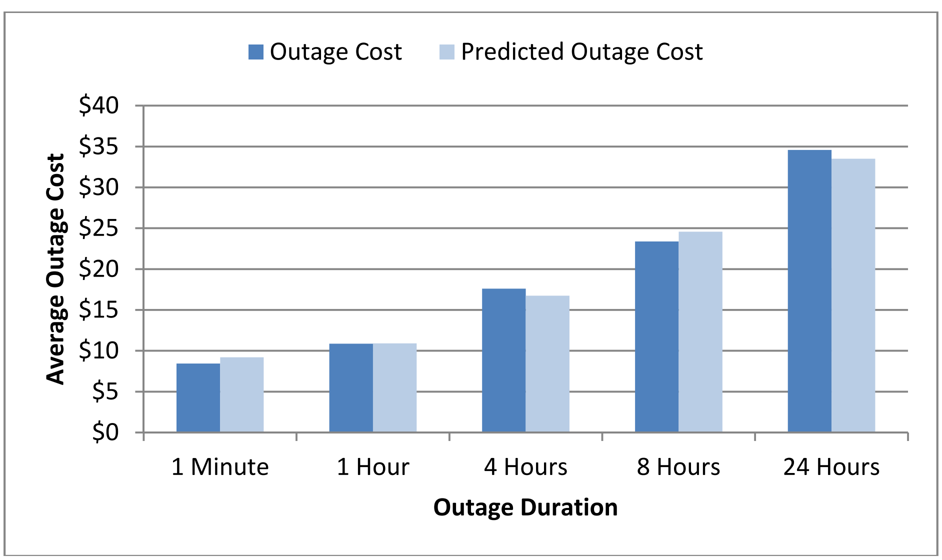
insignificant individually, however, they are included in the regression models because they are jointly significant and still increase predictive power.

Table A-1:
Coefficients of Customer Damage Function – Residential
(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	0.062	0.187***
Duration	0.118***	0.085***
Duration Squared	-0.004***	-0.002***
Outage Timing		
Summer Night	-0.376**	-0.128
Winter Night	-0.369**	-0.065
Summer Morning	-0.202	-0.184
Winter Morning	-0.181	0.171
Summer Afternoon	-0.316**	0.136
Winter Afternoon	-0.279*	-0.156
Summer Evening	-0.273*	-0.028
Winter Evening (Base)	(omitted)	(omitted)
Constant	0.227*	3.052***

Figure A-1 provides a comparison of the model predicted and reported outage cost values by outage duration. The model predicts well across all outage durations. The percent error for a 24-hour outage is -3%; an 8-hour outage is 5%; a 4-hour outage, -5%; an hour, 0%; and 1 minute, 9%.

Figure A-1:
Comparison of Predicted and Reported Outage Cost by Outage Duration – Residential



A.2 Small/Medium Business Customers

For SMB customers, variables that capture the size, outage timing, outage duration, and industry group were included for each premise. Multiple two-part models were tested. The criteria for selection of the final model included performance on out-of-sample tests, performance on in-sample tests and significance of coefficients on important variables.

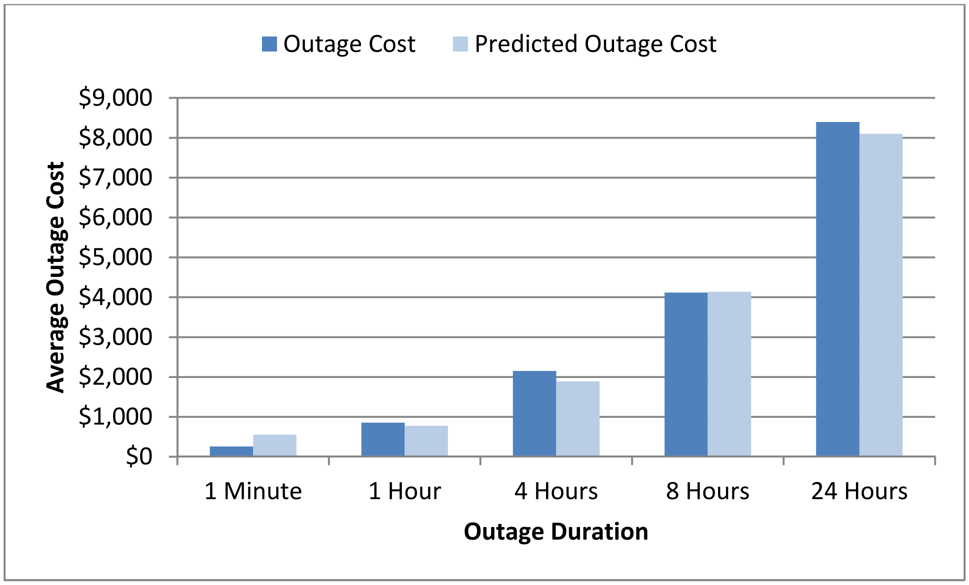
Table A-2 shows the variables included in the SMB customer regression model and the estimated coefficients for each part of the model. The coefficient on the usage variable is significant at the 1% level for the GLM model and the duration variables are significant at the 1% level for both models. Several of the outage timing variables are statistically significant for the Probit model, indicating that outage timing determines both whether or not an SMB customer experiences outage costs. Specifically, customers with morning and afternoon outages (as opposed to evening and night outages) were more likely to report a cost above zero. The industry variables are insignificant individually, however, they are included in the regression models because they are jointly significant and still increase predictive power.

Table A-2:
Coefficients of Customer Damage Function – SMB
(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	0.041	0.367***
Duration	0.223***	0.217***
Duration Squared	-0.006***	-0.006***
Outage Timing		
Summer Night	-0.067	-0.021
Winter Night	-0.163	0.288
Summer Morning	1.172***	0.522*
Winter Morning	0.967***	0.714*
Summer Afternoon	0.651**	0.244
Winter Afternoon	0.866***	0.177
Summer Evening	-0.025	-0.028
Winter Evening (Base)	(omitted)	(omitted)
Industry		
Agriculture, Agricultural Processing & Food Processing	(omitted)	(omitted)
Assembly/Light Industry/High Tech	0.048	-0.425
Grocery Store/Restaurant	0.384	-0.226
Lodging (hotel, health care facility, dormitory, etc.)	-0.12	0.038
Office	-0.495	-0.35
Retail	0.041	0.317
Other/Unknown	-0.335	0.022
Constant	-0.672**	6.065***

Figure A-2 provides a comparison of the model predicted and reported outage cost values by outage duration. The model predicts relatively well across all outage types. The percent error for a 24-hour outage is -4%; an 8-hour outage is 0%; a 4-hour outage, -12%; an hour, -9%; and 1 minute, 116%. Although the percentage difference for a 1-minute outage is quite high, the magnitude of the difference is not substantial considering that 1-minute outage costs are relatively low.

Figure A-2:
Comparison of Predicted and Reported Outage Cost by Outage Duration – SMB



A.3 Large Commercial & Industrial Customers

To predict outage costs for large business customers, Nexant estimated an econometric model from the survey data. Nexant included variables that capture the size, season, basic outage timing (night versus day), whether or not the premise is a multitenant facility, and variables to capture the duration of the outage. The Probit model also included basic industry group (commercial, industrial, public/institutional, other/unknown). As there were only 84 large business customers in the survey data, this model could not include as many variables as the SMB model.

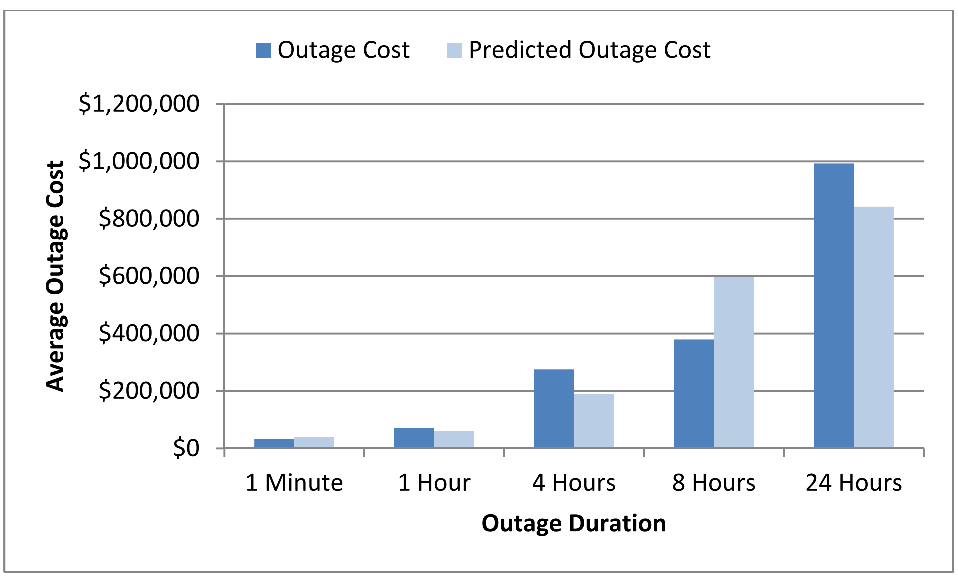
Table A-3 shows the variables included in the large business customer regression model and the estimated coefficients for each part of the model. The natural log of average kW is a significant predictor both of whether or not customers experience outage costs and of the magnitude of outage costs for customers who do report them. Both the duration and duration squared variables are significant at the 1% level in the GLM model. The ‘Summer Night’ and ‘Winter Night’ variables were significant at the 1% level for the GLM model, indicating outages that occur during the night are less impactful to large C&I customers. The multitenant variable, indicating whether the premise has multiple tenants, was not significant in the GLM model. This indicates that whether or not a premise has multiple tenants is an important predictor of the magnitude of outage costs for a given premise. The variable was not included in the Probit model due to data limitations.

Table A-3:
Coefficients of Customer Damage Function – Large Business
(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	-0.635***	0.747***
Duration	0.025	0.432***
Duration Squared	-0.001	-0.013***
Master Metered	(omitted)	-0.822
Outage Timing		
Summer Night	0.282	-1.029***
Winter Night	0.711	-1.228***
Summer Day	-0.202	0.056
Winter Day (Base)	(omitted)	(omitted)
Industry		
Commercial (Base)		-
Industrial	(omitted)	-
Other/Unknown	0.235	-
Public/Institutional	1.207**	-
Constant	4.395**	5.860***

Figure A-3 provides a comparison of the model predicted and reported outage cost values by outage duration. The percent error for a 24-hour outage is -15%; an 8-hour outage is 58%; a 4-hour outage, -31%; an hour, -16%; and 1 minute, 21%.

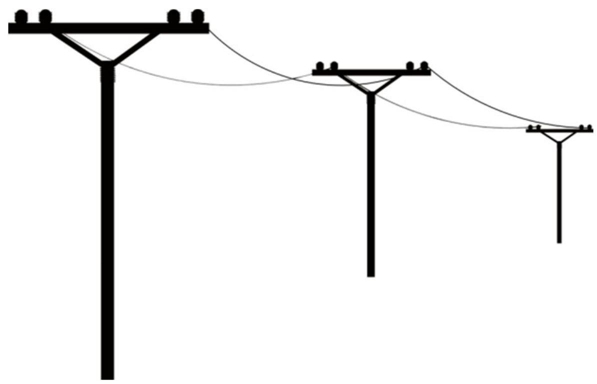
Figure A-3: Comparison of Predicted and Reported Outage Cost by Outage Duration – Large Business



Appendix B Residential Survey Instrument

Toronto Hydro 2017
Value of Service Study

Residential Customers



Thank you in advance for participating in this valuable study. Completing the survey will only take a few minutes of your time.

If you share a building with other owners or tenants, please answer the questions **only about your residence**.

All of your answers will be kept confidential. Your name and address will be kept anonymous and will not be associated with the information you provide.

Please return your completed survey in the enclosed return envelope to receive your $10 cheque as a token of our appreciation. If you have any questions, please contact Nexant Inc., the company we've retained to conduct this study on our behalf, at 1-877-932-0609 (Monday - Friday, 11 a.m. – 8 p.m.).

Sincerely,

Elias Lyberogiannis

Elias Lyberogiannis
General Manager, Engineering

This survey is also available online at: www.torontohydrosurveyres.ca
Your survey ID is «NEXID»

When completing this survey, please note that a "power outage" refers to a complete loss of electricity to your residence. Power outages can be caused by many factors such as bad weather, traffic accidents and equipment failures.

1. In the **past 12 months**, about how many outages of the durations listed below have you had at your home? Write in the number of outages on the blanks. (If none, use "0".)

_______ A short duration (one minute or less)

_______ Longer than one minute and up to 1/2 hour

_______ Longer than 1/2 hour and up to 1 hour

_______ Longer than 1 hour and up to 4 hours

_______ Longer than 4 hours and up to 24 hours

_______ Over 24 hours

2. Do you feel that the number of power outages your residence experiences is…

- ☐ Very low
- ☐ Low
- ☐ Moderate
- ☐ High
- ☐ Very high

3. How satisfied are you with the reliability of the electrical service you receive from Toronto Hydro?

- ☐ Very dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat satisfied
- ☐ Very satisfied
- ☐ Don't know

4. Do you or any of your household members work at home most of the time?

- ☐ No
- ☐ Yes -- What kind of business is it? ____

4a. **If you answered "Yes" in question 4**, how are you compensated for the work you perform at home?

- ☐ Self-employed
- ☐ Salary from employer
- ☐ Hourly wage from employer

5. Do you or does anyone in your household have any health conditions for whom a power outage could be a problem?
   - ☐ No
   - ☐ Yes – Please explain: ____

5a. **If you answered "Yes" in question 5**, have you registered with Toronto Hydro for the Life Support Notification Program at torontohydro.com/lifesupport?
   - ☐ No
   - ☐ Yes

Note – this notification program is only for planned power outages. We strongly encourage customers to always have back-up and to plan for power outages caused by unpredictable events.

Next, we'll ask you about 6 different types of electrical power outages. For each type of outage, we would first like to know how you and your household would adjust to the outage. Second, we would like you to estimate the extra expenses that your household would experience as a result of this type of outage as well as the estimated cost of inconvenience or hassle. Some of the expenses and inconveniences that people might experience include using candles if it's dark, going out to eat if you're unable to cook at home, food spoiling, etc.

Because every person may feel differently about the amount of extra expenses and the inconvenience or hassle, there are no right or wrong answers to these questions. We simply want your honest opinion.

IMPORTANT

As you answer the questions, please remember these two definitions:

Inconvenience or hassle costs
When a power outage occurs, a household may experience inconvenience or hassle costs while adjusting to the outage. These may include having to use candles if it's dark, having to dine out, not being able to watch television or not being able to use the internet.

Note: If you have solar photovoltaic (PV) panels installed, your household will still experience the power outage and your PV system will not feed electricity into the grid.

Extra expenses
These may include food spoilage, dining out, or lost wages for lost work time due to outages. In adding up your extra expenses, please do **not** include expenses that your household would have incurred whether or not the power outage happened. For example, if you decided to dine out during the outage **instead of** another night, the cost of the dinner should **not** be considered as an extra expense because it's simply shifted from another night. However, if you had to dine out during the outage **in addition to** another night, the cost of the dinner should be considered an extra expense.

Case A:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **4 hours** your household's electricity is fully restored. Note that **all** of the remaining cases occur at **<<ONSET>>**.

SUMMARY:
Conditions: <<SEASON1>> weekday **Start time:** <<ONSET>>
Duration: 4 hours **End time:** <<END1>>

A1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ____

A2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ [ ] extra expenses **and** inconvenience costs

A3. Of the above amount, how much of it would be **just for the extra expenses**?

$ [ ] extra expenses **only**

A4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $_________

A4a. **If you selected $0 in question A4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case B:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **1 minute** your household's electricity is fully restored.

SUMMARY:
Conditions: <<SEASON1>> weekday **Start time:** <<ONSET>>
Duration: 1 minute **End time:** <<END2>>

B1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ____

B2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ [ ] extra expenses **and** inconvenience costs

B3. Of the above amount, how much of it would be **just for the extra expenses**?

`

$ [ ] extra expenses **only**

B4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $__________

B4a. **If you selected $0 in question B4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case C:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **1 hour** your household's electricity is fully restored.

SUMMARY:

Conditions:	<<SEASON1>> weekday	**Start time:**	<<ONSET>>
Duration:	1 hour	**End time:**	<<END3>>

C1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ____

C2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ ________ extra expenses **and** inconvenience costs

C3. Of the above amount, how much of it would be **just for the extra expenses**?

$ ________ extra expenses **only**

C4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $_________

C4a. **If you selected $0 in question C4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case D:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **8 hours** your household's electricity is fully restored.

SUMMARY:

Conditions:	<<SEASON1>> weekday	**Start time:**	<<ONSET>>
Duration:	8 hours	**End time:**	<<END4>>

D1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

☐ There's generally no one home at this time
☐ Stay home and do activities that don't require electricity
☐ Go out and eat, shop or visit friends
☐ Run a backup power generator
☐ Use a gas stove for indoor cooking
☐ Use a BBQ/propane grill or camping stove for outdoor cooking
☐ Reset clocks and appliances after outage
☐ Other (please describe) ____

D2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ [ ] extra expenses **and** inconvenience costs

D3. Of the above amount, how much of it would be **just for the extra expenses**?

$ [ ] extra expenses **only**

D4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $_________

D4a. **If you selected $0 in question D4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

☐ Worth nothing
☐ Other reason (please explain)

____

____

Case E:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **24 hours** your household's electricity is fully restored.

SUMMARY:
Conditions: <<SEASON1>> weekday — **Start time:** <<ONSET>>
Duration: 24 hours — **End time:** <<END5>>

E1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ______________________________

E2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ ________ extra expenses **and** inconvenience costs

E3. Of the above amount, how much of it would be **just for the extra expenses**?

$ ________ extra expenses **only**

E4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $__________

E4a. **If you selected $0 in question E4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case F:
On a **<u><<SEASON2>></u>** weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **4 hours** your household's electricity is fully restored.

SUMMARY:

Conditions:	**<u><<SEASON2>></u>** weekday	**Start time:**	<<ONSET>>
Duration:	4 hours	**End time:**	<<END6>>

F1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ____

F2. How much do you think it would cost your household in extra expenses **<u>and</u>** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ ________ extra expenses **<u>and</u>** inconvenience costs

F3. Of the above amount, how much of it would be **just for the extra expenses**?

$ ________ extra expenses **<u>only</u>**

F4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $__________

F4a. **If you selected $0 in question F4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

ACCEPTABLE LEVEL OF RELIABILITY

Toronto Hydro works hard to prevent power outages, but eliminating all outages would be very costly, if not impossible. The following questions help us understand what you consider an acceptable level of service reliability from Toronto Hydro.

If each of the following occurred, would you think you were getting an acceptable or unacceptable level of service reliability?

6. An outage lasting **1 minute or less**... (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

7. An outage lasting **about an hour**... (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

8. An outage lasting between **4 hours and 8 hours**... (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

To better understand how electrical power outages affect your household, we would like to gather some information on your household characteristics. Please answer the following questions to the best of your ability. If you live in an apartment building or duplex, answer only for the part of the building you actually live in.

Some background information about the people living in your household will also help us understand how electrical power outages would affect your household. Again, all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

9. What type of residence is this? Please check one.

- ☐ Single family house (house on separate lot)
- ☐ Row or townhouse (walls adjacent to another house)
- ☐ A unit in a multi-family structure, 2-4 attached units (example: duplex, triplex, fourplex, or single family house converted to flats)
- ☐ A unit in a large multiple family structure, 5 or more attached units (example: apartment house, high rise condominium, garden apartments)
- ☐ Mobile home, house trailer
- ☐ Other (please describe) ______________________________

10. Do you own or rent your residence?

☐ Own ☐ Rent/Lease ☐ Other (specify) ________________________

11. How many years have you lived at this address? (If less than 1 year, write "0".)

_______Years

12. Which of the following best describes your household? Please choose one.

- ☐ Individual living alone
- ☐ Single head of household with children at home
- ☐ Couple with children at home
- ☐ Couple without children at home
- ☐ Unrelated individuals sharing a residence
- ☐ Other (please describe) ______________________________

13. In approximately what year was this residence built? ________

14. What is the size of your residence? ________square feet

15. How many people, **including yourself**, live in your home? ________

16. Please indicate the number of individuals in your household who are in each of these age groups.

_______ Under 6 _______ 25 to 34 _______ 55 to 59

_______ 6 to 18 _______ 35 to 44 _______ 60 to 64

_______ 19 to 24 _______ 45 to 54 _______ 65 or over

17. Which one of the following age groups best describes your age?

☐ Under 25 ☐ 25 to 44 ☐ 45 to 64 ☐ 65 or over

18. Which of the following categories best describes your total household income during 2017 before taxes and other deductions? Please include all income to the household including social security, interest, welfare payments, child support, etc.

☐ 0 - $9,999 ☐ $20,000 - $29,999 ☐ $50,000 - $74,999

☐ $10,000 - $14,999 ☐ $30,000 - $39,999 ☐ $75,000 - $99,999

☐ $15,000 - $19,999 ☐ $40,000 - $49,999 ☐ $100,000 or more

19. Do you own an electric vehicle?

☐ Yes ☐ No

20. Is electricity your primary source of heating in winter?

☐ Yes ☐ No ☐ I don't know

Please share any additional comments:

....

....

....

....

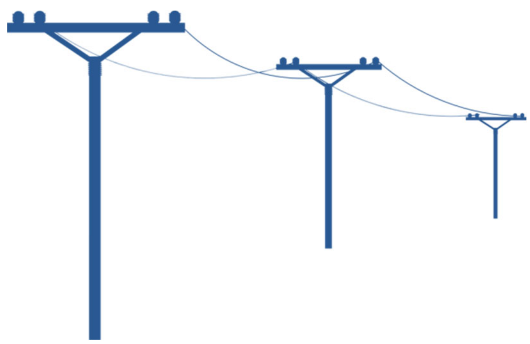
....

Please be sure to return your completed survey.
Thank you!

Appendix C Small/Medium Business Survey Instrument

Toronto Hydro
2017 Value of Service Study

Business Customers



Dear Customer,

Thank you for agreeing to participate in this important study. We're asking you to fill out this survey thinking <u>only</u> about the facilities that your company occupies **at this location:**

«SERVICE_ADDRESS», «SERVICE_CITY»

If your company shares a building with other businesses or you're the property manager at the above address(es), please answer the questions **only for the space <u>your company</u> occupies at this location and the activities <u>your company</u> undertakes**.

All your answers will be kept confidential. Your name and your company's name and address will be kept anonymous and will not be associated with the information you provide.

Please complete the survey to receive your $50 cheque. If you have any questions, please contact Nexant Inc., the company we've retained to conduct this study on our behalf, at 1-877-932-0609 (Monday - Friday, 9 a.m. – 8 p.m.).

Sincerely,

Elias Lyberogiannis

Elias Lyberogiannis
General Manager, Engineering

«NEXID»

When completing this survey, please note that a "power outage" refers to a complete loss of electricity to your facility. Power outages can be caused by many factors, such as bad weather, traffic accidents, and equipment failures.

1. In the **past 12 months**, about how many outages of the durations listed below have you had at your business location? Write in the number of outages on the blanks. (Use "0" if none.)

   A) Short duration or momentary (one minute or less) ________

   B) Longer than one minute and up to 1/2 hour ________

   C) Longer than 1/2 hour and up to 1 hour ________

   D) Longer than 1 hour and up to 4 hours ________

   E) Longer than 4 hours and up to 24 hours ________

   F) Over 24 hours ________

2. In general, how disruptive have these outages been for your company? (Please check one number.)

❑	❑	❑	❑	❑	❑	❑
1	2	3	4	5	6	7
Not at all disruptive						Very disruptive

3. Has your company ever sent employees home during a power outage?

   ❑1 No
   ❑2 Yes

4. In general, how long can an outage last at your facility before the costs become significant? Please estimate that time length in minutes and/or hours:

   __________ **Hours and** __________ **Minutes**

«NEXID»

5. How much advance warning of a power outage does your company need to significantly reduce the problems caused by a power outage?

- ❑1 Advance notice would not reduce problem(s)
- ❑2 At least 1 hour
- ❑3 At least 4 hours
- ❑4 At least 8 hours
- ❑5 At least 24 hours

How satisfied are you with… (Please check one number.)	**Extremely Dissatisfied**						**Extremely Satisfied**
6. The reliability of the electrical service your company has experienced in the **last 12 months**?	❑ 1	❑ 2	❑ 3	❑ 4	❑ 5	❑ 6	❑ 7
7. The length of time it usually takes to restore service after an outage?	❑ 1	❑ 2	❑ 3	❑ 4	❑ 5	❑ 6	❑ 7
8. The responsiveness of Toronto Hydro when you have a power outage?	❑ 1	❑ 2	❑ 3	❑ 4	❑ 5	❑ 6	❑ 7

The next section describes **six** different types of power outages. We'd like to know the **costs to your business** of adjusting to each of these power outages.

For many businesses, the costs of a power outage depend upon the particular situation, and **may vary** from day to day depending upon business conditions. So for each outage type you'll be given the opportunity to report the **range of outage costs** that your business might face (from low to high), as well as to estimate **the cost that you would most likely have** under typical circumstances.

It's important to try to answer all of the questions. If a question is difficult for you to answer, **please give us an estimate** and feel free to **write down any comments about your answer**.

Case 1:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **4 hours** your company's electricity is fully restored. Note that **all** of the remaining cases occur at **«ONSET».**

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	4 hours	**End time:**	«END1»

9. How disruptive would this power outage be to your business?
(Please check one number.)

❑	❑	❑	❑	❑	❑	❑
1	2	3	4	5	6	7
Not disruptive at all						Very disruptive

10. Would your operations or services typically stop or slow down as a result of this power output? (If yes, please state the number of hours.)

❑1 No--------------------> SKIP TO CASE 2 ON PAGE 6

❑2 Yes-------------------->__________ Number of hours that operations or services would stop or slow down (include time **during and after** the power outage)

11. What's the approximate dollar value of the operations or services that typically would be lost, at least temporarily, during the power outage and any slow period after the power outage? (If you're not sure please make your best guess.)

$__________ value of lost work or services

12. What percent of the operations or services typically would be made up after the power outage? (Please check one number.)

❑	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%

13. Would there be **labour costs** associated with this power outage such as salaries and wages for staff who would be unable to work or overtime pay to make up for operations or services? (If yes, please state the cost for lost labour as well as the cost for overtime labour to make up for lost work.)

❑1 No
❑2 Yes -->$_______labour costs of staff unable to work during the power outage

$_______labour costs in overtime/extra shifts to make up for lost work

14. Would there be any **damage costs** associated with this power outage such as damage to equipment, materials, etc.? (If yes, please state how much the damage cost for equipment would be and how much the damage cost to materials would be.)

- ❑1 No
- ❑2 Yes --->$_______damage to equipment

  $_______damage to materials

15. Would there be **additional tangible costs** associated with this power outage (such as extra restart costs, and costs to run and/or rent backup equipment)? (If yes, please state the additional costs.)

- ❑1 No
- ❑2 Yes --->$_______additional tangible costs

16. If you had to put a dollar value on **intangible costs** due to this power outage (such as inconvenience or dissatisfied customers), what would these costs be? (If yes, please state the intangible cost.)

- ❑1 No, there would be $0 intangible costs
- ❑2 Yes, there would be $_______ intangible costs

17. In addition to the costs discussed above, some organizations may avoid business expenses because of electrical outages. Some examples include a lower electrical bill, lower material outlays, and lower personnel costs. Would you experience any savings associated with this power outage? (If yes, please state the savings.)

- ❑1 No
- ❑2 Yes --->$_______savings

18. Considering **all** of the costs you might experience as a result of this **<u>4-hour «SEASON1» weekday outage beginning at «ONSET»</u>**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	**$__________**	**$__________**
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 2:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **1 minute** your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	1 minute	**End time:**	«END2»

19. Considering **all** of the costs you might experience as a result of this **1-minute «SEASON1» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	$__________	$__________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 3:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **1 hour** your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	1 hour	**End time:**	«END3»

20. Considering **all** of the costs you might experience as a result of this **1-hour «SEASON1» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	$__________	$__________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 4:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **8 hours** your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	8 hours	**End time:**	«END4»

21. Considering **all** of the costs you might experience as a result of this **<u>8-hour «SEASON1» weekday outage beginning at «ONSET»</u>**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	$__________	$__________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 5:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **24 hours** your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	24 hours	**End time:**	«END5»

22. Considering **all** of the costs you might experience as a result of this **<u>24-hour «SEASON1» weekday outage beginning at «END5»</u>**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	$__________	$__________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 6:
On a **«SEASON2»** weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **4 hours** your company's electricity is fully restored.

SUMMARY:

Conditions:	**«SEASON2»** weekday	**Start time:**	«ONSET»
Duration:	4 hours	**End time:**	«END6»

23. Considering **all** of the costs you might experience as a result of this **4-hour «SEASON2» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	**$__________**	**$__________**
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

WHAT LEVEL OF RELIABILITY IS ACCEPTABLE?

Toronto Hydro works hard to prevent power outages, but eliminating all outages could be very costly, if not impossible.

The following questions help us understand what you consider acceptable service from Toronto Hydro.

24. If each of the following occurred, would you think you were getting acceptable or unacceptable service from Toronto Hydro? Please check a box for each statement whether you find the outage period acceptable or unacceptable.

Outages lasting **1 minute or less...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **about an hour...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **between 4 hours and 8 hours…**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

ABOUT YOUR BUSINESS

Some background information about your company will help us understand how power outages affect your type of business.

Please remember all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

25. Which of the following categories best describes your business? (Please check one.)

- ❑ 1 Agriculture/Agricultural Processing
- ❑ 2 Assembly/Light Industry
- ❑ 3 Chemicals/Paper/Refining
- ❑ 4 Food Processing
- ❑ 5 Grocery Store/Restaurant
- ❑ 6 Lodging (hotel, health care facility, dormitory, prison, etc.)
- ❑ 7 High Tech
- ❑ 8 Lumber/Mining/Plastics
- ❑ 9 Office
- ❑ 10 Oil/Gas Extraction
- ❑ 11 Retail
- ❑ 12 Stone/Glass/Clay/Cement
- ❑ 13 Transportation
- ❑ 14 Utility
- ❑ 15 Other (please specify):______________________________

26. What's the approximate square footage of the facility referred to at the beginning of the survey? (Note: "facility" refers to the building(s) that your business occupies at that location.)

__________ Square feet

27. How many **full-time** (30+ hours per week) employees are employed by your company at that location?

__________ Full-time employees

28. List the number of people employed by your business at this company location in each of the following categories:

___________ # of part-time year-round employees

___________ # of full-time seasonal employees

___________ # of part-time seasonal employees

29. What's the approximate value of your business's total annual revenue?

$___________ per year

30. What's the approximate value of your business's total annual expenses (including labour, rent, materials, and other overhead expenses)?

$___________ per year

31. Approximately what percentage of your business's annual operating budget is spent on electricity?

___________ %

32. Does your company have any electrical equipment that's sensitive to fluctuations in voltage, frequency, short interruptions (less than two seconds), or other such irregularities in electricity supply? (If yes, please state the type of equipment.)

❑1 No
❑2 Yes ---->What equipment? ____________________________________

33. Does your business own or rent/lease any of the following devices to protect this equipment? (Please check all that apply.)

❑1 Back-up generator(s)
❑2 Uninterruptible power supply
❑3 Line conditioning device(s)
❑4 Surge suppressor(s)
❑5 Isolation transformer(s)

34. Does your business have any electrical equipment that would continue to operate during a power outage? (If yes, please state the type of equipment.)

❑1 No
❑2 Yes ----->What equipment? ____________________________________

Please share any additional comments:

____

____

____

____

____

____

____

____

____

____

THANK YOU FOR YOUR HELP!

Please provide your contact information so that we may mail you the incentive cheque.

The incentive cheque can be made out to any individual or charitable organization as designated by you. It should arrive in 2-4 weeks.

If you choose not to accept any incentive, please write “decline.”

Name on cheque: ____

Address (Line 1): ____

Address (Line 2): ____

City: ____

Province: ____

Postal Code: ____

Appendix D Large C&I Survey Instrument

Associated Delivery Numbers (Acct #)

NEXID #: «NEXID»

Date of Interview: ____________________

Interviewer Name: ____________________

Interview Start Time: _________________

Interview End Time: _________________

Name: **Title:**

Name: **Title:**

Name: **Title:**

I'd like to talk to you about the costs of power outages for:
(Describe the part of the site served by the selected deliveries.)

Company Name:

Service Address:

If delivery serves only part of the site, describe location served:

OUTAGE SCENARIOS

Case	Season	Day	Start Time	End Time	Duration
1	«SEASON1»	Weekday	«ONSET»	«END1»	4 hours
2	«SEASON1»	Weekday	«ONSET»	«END2»	1 minute
3	«SEASON1»	Weekday	«ONSET»	«END3»	1 hour
4	«SEASON1»	Weekday	«ONSET»	«END4»	8 hours
5	«SEASON1»	Weekday	«ONSET»	«END5»	24 hours
6	**«SEASON2»**	Weekday	«ONSET»	«END6»	4 hours

What are the operating hours of this facility?

Use military time. If open 24 hours, use 00:00 to 00:00.

	Weekday Open	Weekday Close	Saturday Open	Saturday Close	Sunday Open	Sunday Close
Shift 1						
Shift 2						
Shift 3						

PRODUCT AND PROCESS DESCRIPTION

1) What products do you make and/or what services do you provide at this facility?

____

____

____

____

____

2) What processes do you use to make these products and/or generate these services?

____

____

____

____

____

OUTAGE EXPERIENCE

In the past 12 months, about how many outages of the durations listed below have you had at this business location? Write a number in each blank. *(Use 0 if none.)*

3.1) Short duration or momentary (one minute or less) _______

3.2) Longer than one minute and up to ½ hour _______

3.3) Longer than ½ hour and up to 1 hour _______

3.4) Longer than 1 hour and up to 4 hours _______

3.5) Longer than 4 hours and up to 24 hours _______

3.6) Over 24 hours _______

MOST RECENT OUTAGE EVENTS

Please describe your three most recent power outages:

	Outage Date *Mo/Yr*	Duration *Hrs/Mins/Secs*	Time *Military*	Weather Conditions *Clear/Stormy*	Description of Impacts
3.7)	_______	_________	______	________	____
3.8)	_______	_________	______	________	____
3.9)	_______	_________	______	________	____

4) What normally happens to your facility's operations when a prolonged power outage (lasting more than one minute) occurs?
(Prompt for major equipment affected, worst effects on operations, etc.)

____

____

____

5.1) Does an outage at this location have financial effects on other sites owned by your company?
1) Yes 2) No *(if No, skip to Q5.4)*

5.2) What type(s) or duration(s) of outages at this location have financial effects on other sites owned by your company?
(Probe for interdependencies of the production network.)

____

____

____

5.3) What are the specific financial effects?

____

____

____

____

5.4) Does an outage at this location have financial effects at your customers' sites?

1) Yes 2) No

6.1) Does your firm generate any of its own electricity (separate from backup power)?

1) Yes 2) No *(if No, skip to Q6.4)*

6.2) What percentage of your electrical demand is supplied by your generation equipment?

_______________ %

6.3) What is the rated capacity of your generation equipment?

____________ Circle one: kW MW hp

6.4) Does your firm have some form of backup electrical power?
1) Yes 2) No *(if No, skip to Q1C1)*

6.5) What percentage of your electrical demand could be supplied by your backup generation equipment?

_______________ %

6.6) What's the rated capacity of your backup generation equipment?

____________ Circle one: kW MW hp

The next section describes six different types of power outages. We'd like to know the costs to your business of adjusting to each of these power outages. **Assume that all of the described outages arise from issues associated with Toronto Hydro's infrastructure and occur <u>without advance warning</u>, which means that you don't initially know how long each outage will last.**

For many businesses, the costs of a power outage depend upon the particular situation, and may vary from day to day depending upon business conditions. For each outage type, please estimate the costs that you'd be most likely to have under average circumstances.

Since some businesses have more than one building at one location, and others have multiple buildings in several locations, please remember to fill out these questions thinking <u>only</u> about the building(s) that your business occupies at the location specified for this survey.

It's important to try to answer all of the questions. If a question is difficult for you to answer, please give us an estimate and feel free to provide any comments about your answer.

Case	Season	Day	Start Time	End Time	Duration
1	«SEASON1»	Weekday	«ONSET»	«END1»	4 hours

1C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.1C6)

1C2) By what percentage would activities stop or slow down? __________ %

1C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

1C4) What percent of this lost output is likely to be made up? __________ %

1C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST

1C6) Damage/spoilage to raw or intermediate materials __________ $

1C7) Cost of disposing of hazardous materials __________ $

1C8) Damage to your firm's plant or equipment __________ $

1C9) Costs to run backup generation or equipment __________ $

1C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST

1C11) Savings from unused raw and intermediate materials (except fuel) __________ $

1C12) Savings on your firm's fuel (electricity) bill __________ $

1C13) Scrap value of damaged products or inputs __________ $

LABOUR COST

1C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

1C15) Labour costs to make-up lost output __________ $

1C16) Extra labour costs to restart activities __________ $

1C17) Savings from wages that were not paid __________ $

1C18) Other costs __________ $

1C19) Other savings __________ $

1C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

Case	Season	Day	Start Time	End Time	Duration
2	«SEASON1»	Weekday	«ONSET»	«END2»	1 minute

2C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.2C6)

2C2) By what percentage would activities stop or slow down? __________ %

2C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

2C4) What percent of this lost output is likely to be made up? __________ %

2C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST

2C6) Damage/spoilage to raw or intermediate materials __________ $

2C7) Cost of disposing of hazardous materials __________ $

2C8) Damage to your firm's plant or equipment __________ $

2C9) Costs to run backup generation or equipment __________ $

2C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST

2C11) Savings from unused raw and intermediate materials (except fuel) __________ $

2C12) Savings on your firm's fuel (electricity) bill __________ $

2C13) Scrap value of damaged products or inputs __________ $

LABOUR COST

2C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

2C15) Labour costs to make-up lost output __________ $

2C16) Extra labour costs to restart activities __________ $

2C17) Savings from wages that were not paid __________ $

2C18) Other costs __________ $

2C19) Other savings __________ $

2C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

Case	Season	Day	Start Time	End Time	Duration
3	«SEASON1»	Weekday	«ONSET»	«END3»	1 hour

3C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.3C6)

3C2) By what percentage would activities stop or slow down? __________ %

3C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

3C4) What percent of this lost output is likely to be made up? __________ %

3C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST

3C6) Damage/spoilage to raw or intermediate materials __________ $

3C7) Cost of disposing of hazardous materials __________ $

3C8) Damage to your firm's plant or equipment __________ $

3C9) Costs to run backup generation or equipment __________ $

3C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST

3C11) Savings from unused raw and intermediate materials (except fuel) __________ $

3C12) Savings on your firm's fuel (electricity) bill __________ $

3C13) Scrap value of damaged products or inputs __________ $

LABOUR COST

3C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

3C15) Labour costs to make-up lost output __________ $

3C16) Extra labour costs to restart activities __________ $

3C17) Savings from wages that were not paid __________ $

3C18) Other costs __________ $

3C19) Other savings __________ $

3C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

Case	Season	Day	Start Time	End Time	Duration
4	«SEASON1»	Weekday	«ONSET»	«END4»	8 hours

4C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.4C6)

4C2) By what percentage would activities stop or slow down? __________ %

4C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

4C4) What percent of this lost output is likely to be made up? __________ %

4C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST

4C6) Damage/spoilage to raw or intermediate materials __________ $

4C7) Cost of disposing of hazardous materials __________ $

4C8) Damage to your firm's plant or equipment __________ $

4C9) Costs to run backup generation or equipment __________ $

4C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST

4C11) Savings from unused raw and intermediate materials (except fuel) __________ $

4C12) Savings on your firm's fuel (electricity) bill __________ $

4C13) Scrap value of damaged products or inputs __________ $

LABOUR COST

4C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

4C15) Labour costs to make-up lost output __________ $

4C16) Extra labour costs to restart activities __________ $

4C17) Savings from wages that were not paid __________ $

4C18) Other costs __________ $

4C19) Other savings __________ $

4C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

Case	Season	Day	Start Time	End Time	Duration
5	«SEASON1»	Weekday	«ONSET»	«END5»	24 hours

5C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.5C6)

5C2) By what percentage would activities stop or slow down? __________ %

5C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

5C4) What percent of this lost output is likely to be made up? __________ %

5C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST

5C6) Damage/spoilage to raw or intermediate materials __________ $

5C7) Cost of disposing of hazardous materials __________ $

5C8) Damage to your firm's plant or equipment __________ $

5C9) Costs to run backup generation or equipment __________ $

5C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST

5C11) Savings from unused raw and intermediate materials (except fuel) __________ $

5C12) Savings on your firm's fuel (electricity) bill __________ $

5C13) Scrap value of damaged products or inputs __________ $

LABOUR COST

5C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

5C15) Labour costs to make-up lost output __________ $

5C16) Extra labour costs to restart activities __________ $

5C17) Savings from wages that were not paid __________ $

5C18) Other costs __________ $

5C19) Other savings __________ $

5C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

Case	Season	Day	Start Time	End Time	Duration
6	**«SEASON2»**	Weekday	«ONSET»	«END6»	4 hours

6C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.6C6)

6C2) By what percentage would activities stop or slow down? __________ %

6C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

6C4) What percent of this lost output is likely to be made up? __________ %

6C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST

6C6) Damage/spoilage to raw or intermediate materials __________ $

6C7) Cost of disposing of hazardous materials __________ $

6C8) Damage to your firm's plant or equipment __________ $

6C9) Costs to run backup generation or equipment __________ $

6C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST

6C11) Savings from unused raw and intermediate materials (except fuel) __________ $

6C12) Savings on your firm's fuel (electricity) bill __________ $

6C13) Scrap value of damaged products or inputs __________ $

LABOUR COST

6C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

6C15) Labour costs to make-up lost output __________ $

6C16) Extra labour costs to restart activities __________ $

6C17) Savings from wages that were not paid __________ $

6C18) Other costs __________ $

6C19) Other savings __________ $

6C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

7.1) Now that we have discussed the *direct* costs associated with these outages, would you experience any *intangible* costs such as loss of good will, potential liability, or loss of future customers?

1) Yes *(if Yes, please explain)*
2) No

____

____

____

ACCEPTABLE LEVEL OF RELIABILITY

Toronto Hydro works hard to prevent power outages, but eliminating all outages would be very costly, if not impossible. The following questions help us understand what you consider an acceptable level of service reliability from Toronto Hydro.

8.1) If each of the following occurred, would you think you were getting acceptable or unacceptable service from Toronto Hydro?

Outages lasting **1 minute or less...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **about an hour...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **between 4 hours and 8 hours…**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

ABOUT YOUR BUSINESS

Some background information about your business will help us understand how power outages affect your type of business. Please remember all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

9.1) Which one of the following categories best describes your business?

- ❑ Agriculture/Agricultural Processing
- ❑ Assembly/Light Industry
- ❑ Chemicals/Paper/Refining
- ❑ Food Processing
- ❑ Grocery Store/Restaurant
- ❑ Lodging (hotel, health care facility, dormitory, prison, etc.)
- ❑ High Tech
- ❑ Lumber/Mining/Plastics
- ❑ Office
- ❑ Oil/Gas Extraction
- ❑ Retail
- ❑ Stone/Glass/Clay/Cement
- ❑ Transportation
- ❑ Utility
- ❑ Other *(please specify)*: ______________________________

9.2) What's the approximate square footage of the facility?

__________ Square feet

9.3) How many **full-time** (30+ hours per week) employees are employed by your business at this location?

__________ Full-time employees

9.4) List the number of people employed by your business at this location in each of the following categories:

__________ # of part-time year-round employees

__________ # of full-time seasonal employees

__________ # of part-time seasonal employees

9.5) What's the approximate value of your business' annual operations or services (income)?

$_____________ per year

9.6) What's the approximate value of your business' total annual expenses (including labour, rent, materials, and other overhead expenses)?

$_____________ per year

9.7) Approximately what percentage of your business' annual operating budget is spent on electricity?

__________ %

That concludes our interview today. Thank you very much for your time.

Please have customer sign / initial below acknowledging receipt of the $150 cheque.

Customer Name: ____ Date: _____________________

FOR INTERNAL USE ONLY:

Based on your observations of this facility, give a brief summary of the facility, any freak occurrences with their power supply, and the critical factors that minimize and/or exacerbate outage costs.

____

____

____

____

____

____

____

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D4 Capacity Planning, Growth & Electrification

Toronto Hydro's capacity plan ensures that the distribution system is adequately sized to deliver reliable electricity to the utility's customers. To that end, the capacity planning process considers new load connections, increased distributed energy resources ("DERs") and broader electrification activities including the electrification of transportation. Fundamental to the capacity planning process is a 10-year weather-adjusted peak demand forecast ("System Peak Demand Forecast") that is developed using a driver-based forecasting methodology. The System Peak Demand Forecast is the basis for the Regional Planning forecast at the needs assessment stage to assess the adequacy of transmission facilities to supply the distribution grid.[1]

Capacity planning is becoming more complex as utilities address the unprecedented energy transition that is set to unfold over the coming years. National, provincial, and municipal decarbonization targets, as well as technical, societal, and economic factors are driving toward a decarbonized, decentralized and digitized energy system. This shift is expected to expand the role of clean electricity as source of energy for transportation and heating. Despite explicit industry and government net zero emission targets, there are still degrees of uncertainty around how these ambitious goals will be achieved. The pace and timing of the resulting growth and electrification from the pursuit of these targets will be driven by a complex interplay of policy, technological developments and consumer choice. Distribution system capacity planning must manage these interlinked growth drivers in an environment of greater uncertainty. Section D4.3 provides an overview of how Toronto Hydro has addressed this complexity and managed this uncertainty in its investment planning for 2025-2029.

For the 2025-2029 rate period, Toronto Hydro undertook enhanced capacity and connections capability assessments to monitor capacity related risks within its system. The enhancements include the preparation of the 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 long-term scenario modelling tool known as Future Energy Scenarios. The Future Energy Scenarios model is distinct from

[1] Please refer to Exhibit 2B, Section B for more information about Toronto Hydro's role in the Regional Planning Process.

the System Peak Demand Forecast in that it does not attempt to determine the most likely demand based on historical trends and other probabilistic sources of information. Rather, 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 Future Energy Scenarios is described in more detail in Appendix A to this schedule.

This Exhibit describes Toronto Hydro's approach to capacity planning for 2025-2029 and is organized into the following sub-sections:

- **Section D4.1** outlines the capacity planning approach,
- **Section D4.2** describes in impact of growth and electrification considerations on the capacity planning process, and
- **Section D4.3** describes capacity needs and investments over the 2025-2029 period.

D4.1 Capacity Planning

Through its capacity planning process, Toronto Hydro assesses the adequacy of the distribution grid to deliver safe and reliable electricity to current and future customers. This process is linked with Regional Planning to ensure the adequacy of transmission facilities supplying the distribution grid. The System Peak Demand Forecast is the basis for the capacity planning process both at the distribution level and for Regional Planning at the needs assessment stage.

D4.1.1 System Peak Demand Forecast

The System Peak Demand Forecast determines the grid capacity investments that Toronto Hydro needs to make in the 2025-2029 rate period in order to continue to serve its customers and support economic growth and development in the City of Toronto. Using a probabilistic approach to forecast the peak demand at all transformer station buses that supply Toronto Hydro's distribution grid, the System Peak Demand Forecast yields summer and winter demand peaks, with the summer peak driving the 2025-2029 investment plan.

To arrive at the System Peak Demand Forecast, Toronto Hydro modelled organic system growth as part of the base forecast along with specific drivers that are relevant and material to the planning horizon. More specifically, Toronto Hydro considered three new specific drivers in the development of the System Peak Demand Forecast: (i) hyperscale data centers, (ii) electrification of transportation and (iii) Municipal Energy Plans which include large anticipated connections in different areas of the city. Each of these drivers is discussed in further detail below.

The System Peak Demand Forecast methodology includes the following components and considerations:

1. Weather Normalization
2. Econometric Multivariate Regression
3. Hyperscale Data Centre Demand Driver Analysis
4. Electric Vehicle (EV) Demand Driver Analysis
5. Municipal Energy Plans – Uncommitted Connections
6. Monte-Carlo Simulation
7. TS Bus Growth Allocation & Layering of Load Transfers/Voltage Conversions and Customer Connections

D4.1.1.1 Weather Normalization

To determine the correlation between temperature and load, Toronto Hydro's analysis removed the impact of day-to-day fluctuations in temperature on peak load in order to arrive at a stable view of historical system performance. Toronto Hydro then applied the historical trend to the forecasted peak load to normalize the forecast for weather-related impacts.

D4.1.1.2 Econometric Multivariate Regression

In addition to weather, Toronto Hydro considered a range of macroeconomic assumptions as inputs to the System Peak Demand Forecast, including the following key variables:

1. Toronto Population
2. Toronto Employment Rate & Median Income
3. Consumer Price Index
4. Number of Business Licenses Issued/Renewed
5. Toronto Housing Starts
6. Average Home Price

Toronto Hydro relied on traditional forecasting approaches to establish a correlation between weather and peak demand, and between econometric variables and peak demand. Toronto Hydro enhanced the traditional approach by incorporating considerations of the impact of varying weather on economic activity and its relationship to peak demand. This analysis enabled the utility to assess the impact of a changing climate on the econometric variables that affect peak demand.

D4.1.1.3 Hyperscale Data Centre Demand Driver Analysis

Toronto Hydro identified hyperscale data center connections as a new driver of significant peak demand growth over the 2025-2029 rate period and beyond. A hyperscale data center supports large processing and data storage operations using 5,000 servers or more and has the capability of a peak demand exceeding 25 MW. In order to better understand the impact of hyperscale data center connections on the grid and plan accordingly, Toronto Hydro modelled this driver separately. Through review of historical load connections, research into growth rates for comparable North American cities, and assessments of vacancy rates as well as available land space in the City, Toronto Hydro assessed the peak demand contributions of hyperscale data centers.

D4.1.1.4 Electric Vehicle Demand Driver Analysis

Toronto Hydro forecasted the impact of light-duty, medium-duty and heavy-duty EVs. Figure 1 below summarizes the volumes of EVs that underpin the forecast. The adoption models are aligned with the City of Toronto's Transform TO transportation electrification goals. The forecast also considered geographic distribution and typical charging profiles to arrive at area and system peak demand contribution from electric vehicle uptake by consumers.

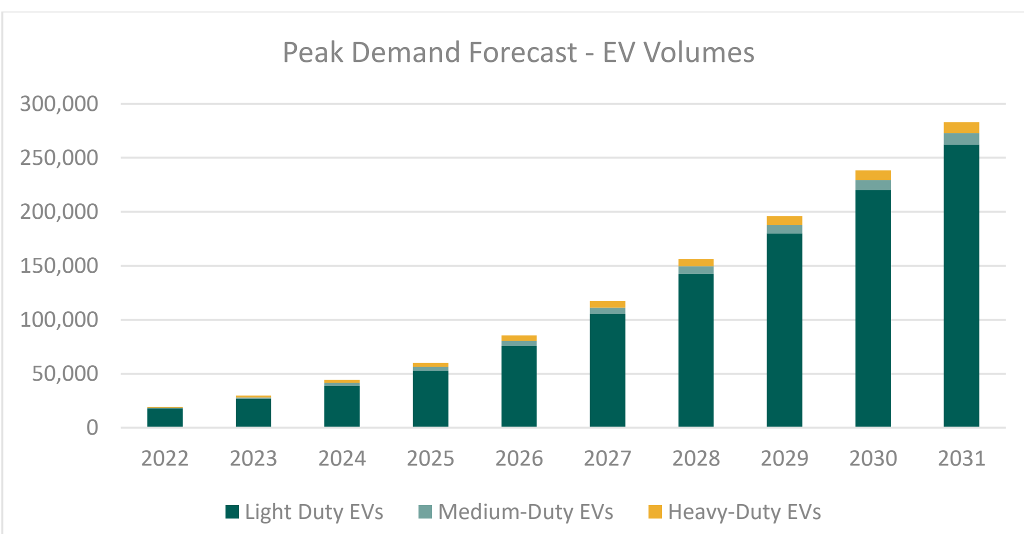


Figure 1: Peak Demand Forecast – EV Volumes

D4.1.1.5 Municipal Energy Plans

In the development of the System Peak Demand Forecast, Toronto Hydro considered the impact of Municipal Energy Plans for large projects, such as the re-development of Downsview, Port Lands and Scarborough Golden Mile.[2] Figure 2, shows the location of these projects in the city.

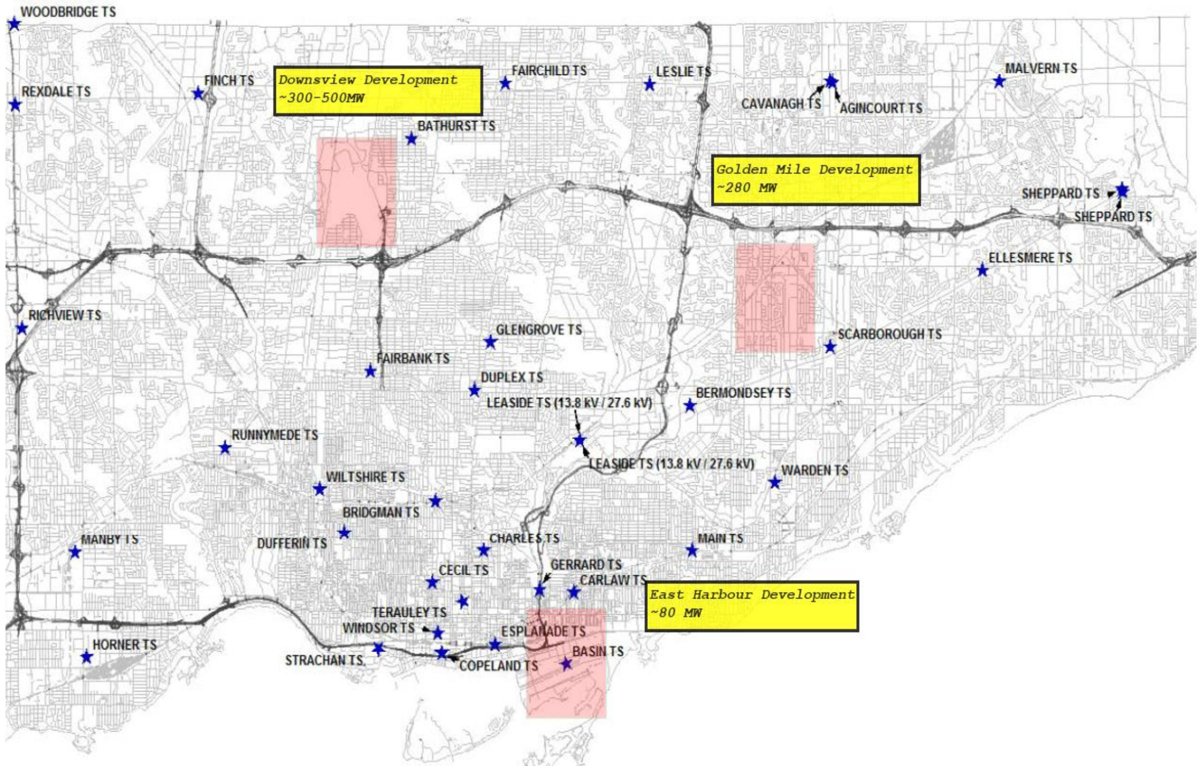


Figure 2: Municipal Energy Plan Locations

For the identified Municipal Energy Plans, Toronto Hydro included both firm connection commitments and the anticipated future loads in the System Peak Demand Forecast to ensure that the utility has sufficient lead-time to invest in new grid capacity that is required to serve this future demand. This approach is consistent with section 3.3.1 of the Distribution System Code which requires distributors to "plan and build the distribution system for reasonable forecast load growth." It is also aligned with the recommendation of the OEB's Regional Planning Process Advisory Group for distributors to incorporate Municipal Energy Plan information into their planning and forecasting

[2] City of Toronto, Official Plans – Secondary Plans, "online", https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/official-plan/chapter-6-secondary-plans/

processes in order to "identify current and future needs for new electricity infrastructure investments within local communities."[3]

D4.1.1.6 Monte-Carlo Simulation

Monte-Carlo Simulation is a sophisticated modelling technique that is applied to model the probability of different outcomes when the potential for random variables is present. It considers multiple sources of uncertainty to provide a range of possible outcomes for peak demand. For the System Peak Demand Forecast, Toronto Hydro modeled the variability of temperature to consider the impact of climate change on econometric indicators and simultaneously included drivers for data centers, electric vehicles, conservation and demand management, and distributed energy resources forecasts and applied a probability to determine the most likely outcome.

D4.1.1.7 TS Bus Growth Allocation and Layering of Load Transfers/Voltage Conversions and Customer Connections

The final step in the forecasting process involves allocating the demand outputs from each driver to the station buses and layering on any permanent load transfers through the Load Demand program to arrive at the System Peak Demand Forecast that describes impacts at both a system and bus level.

D4.1.2 Regional Planning Needs Assessment Forecast

The Toronto regional planning process commenced in the fall of 2022 with the needs assessment phase.[4] The transmitter Hydro One Networks Inc. develops the regional planning needs assessment forecast using an extreme weather model, information from Toronto Hydro's System Peak Demand Forecast and a forecast of Conservation and Demand Management (CDM) and Distributed Generation (DG) from the IESO.

The Needs Assessment Report issued in December 2022 indicates that the net summer peak demand in the Toronto region is expected to increase by an average of 2.1 per cent per year, reaching 6800 MVA by 2031.[5] Figure 3 below shows Toronto Hydro's System Peak Demand Forecast and the Regional Planning Forecast issued by Hydro One. The System Peak Demand Forecast is shown net of the forecasted impacts of CDM and DG. The primary difference between the System Peak Demand

[3] RPPAG, Municipal Information Document – Improving the Electricity Planning Process in Ontario: Enhanced Coordination between Municipalities and Entities in the Electricity Sector, (December 15, 2022) p. 2, "online", https://www.oeb.ca/sites/default/files/RPPAG-Municipal-Information-Document-20221202.pdf
[4] Exhibit 2B, Section B
[5] Exhibit 2B, Section B, Appendix A – Needs Assessment Report (Toronto Region)

Forecast and Regional Planning Needs Assessment forecast is the effect of extreme weather. As noted above, Toronto Hydro normalizes its forecast for weather fluctuations, whereas the Regional Planning Needs Assessment forecast relies on an extreme weather model. Figure 3 shows that Toronto Hydro's grid capacity needs to increase by at least 23% by the next decade.

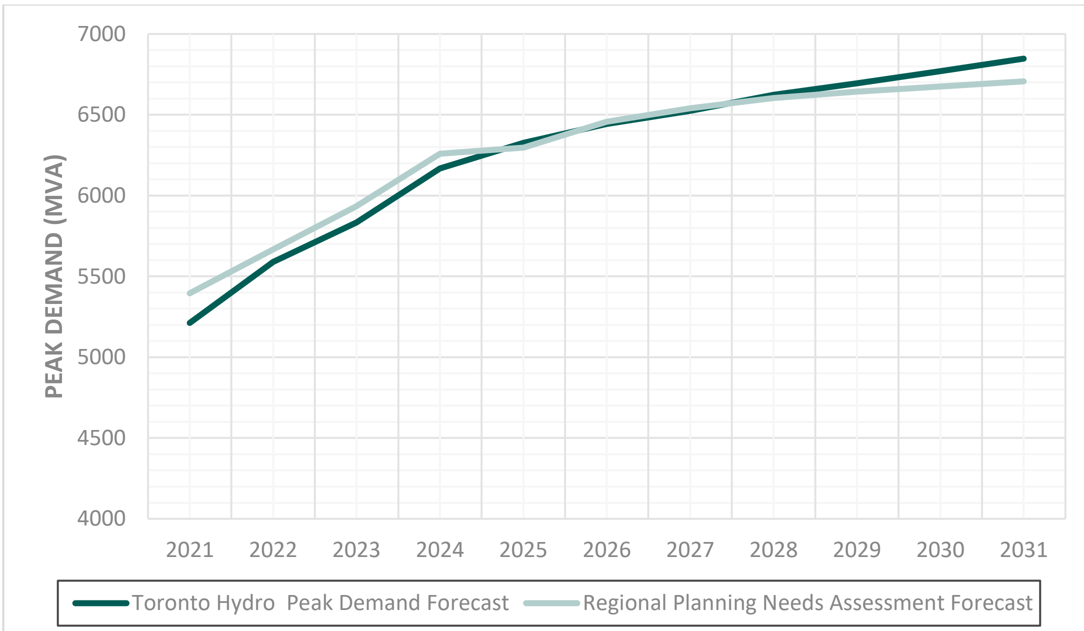


Figure 3: Toronto Hydro System Peak Demand Forecast and the Regional Planning Needs Assessment Forecast prepared by Hydro One

D4.1.3 Connection Capability

In order to connect new customers, Toronto Hydro needs grid capacity as well as spare feeder positions (i.e. feeder breakers to which new feeders can be connected). As existing feeders reach their capacity, new feeders must be pulled from a station into the distribution system to connect new customers. Although a station may have the capacity to supply the required demand, if there are no feeder positions to connect new feeders to the station, the station is unable to support new connections. To this end, Toronto Hydro must monitor the number of spare feeder positions at its stations to maintain the ability to connect new customers. When new feeders are needed and there are spare feeder positions are available, Toronto Hydro initiates projects in the Load Demand program to transfer feeder loads and free up feeder positions so that new customers can connect to the system in a timely and efficient manner.

D4.1.4 Generation Capacity and Capability Assessment

Toronto Hydro connects DERs to the distribution system in alignment with the Distribution System Code and in coordination with Hydro One Networks and the IESO. As part of its capacity planning process, the utility identified a number of constraints that impact DER connections to the distribution grid, including:

- limited breaker and station equipment capacity due to short circuit capacity constraints;
- reverse power flow limitations based on transformer thermal capacity and minimum load requirements;
- anti-islanding conditions for DG; and
- system thermal limits and load transfer capability.

Short circuit capacity constraints on station equipment are the primary constraint for DER connections. To determine the short circuit capacity at stations and other locations on the distribution system, Toronto Hydro employs sophisticated fault and power flow simulation models. These models predict how much fault current will flow to a specific location from generators located throughout the distribution system. The presence of DERs on distribution feeders can contribute to fault current that can cause station equipment, such as circuit breakers, to exceed short circuit capacity limits. Toronto Hydro completes a study for each new DER application to monitor the available existing short circuit capacity of the system.

D4.2 Capacity Planning and the Energy Transition

The decarbonization of the energy system to mitigate the existential and economic impacts of climate change is expected to create new roles for electricity, including powering transportation and building systems. Toronto Hydro recognizes that the pace and timing of these changes are driven by a complex interplay of policy, technological developments and consumer choice. While there is certainty that fundamental change is ahead, there are degrees of uncertainty about how that change will unfold (e.g. the pace and adoption of EVs and heat pumps; the role of low emission gas; and the scale of local vs. bulk electricity supply). To contend with this uncertainty and complexity in its planning process, Toronto Hydro developed the Future Energy Scenarios modelling tool to understand possible changes to future peak demand under different scenarios. For more information about this tool please refer to Appendix A.

In order to be able to continue to deliver its central purpose of serving the electricity needs of the residents, businesses and institutions in the City of Toronto, the utility must take responsible actions in the 2025-2029 plan period to prepare the local grid and its operations for the unprecedented energy transition that is and will continue to gradually unfold across the economy. At the same time, the exact path and pace of the energy transition remains subject to various factors of uncertainty (policy, technology and consumer behavior), which means that Toronto Hydro must be careful to ensure that investments being made in the 2025-2029 rate period provide long-term value to customers and enable policy, technology and customer choice in effecting the energy transition. To balance both of these objectives, Toronto Hydro adopted a "least regrets" planning philosophy. The term "least regrets" refers to a strategic planning approach anchored in the decision-making theory of anticipating and minimizing regretful choices/outcomes when faced with uncertainty.

As part of its capacity planning process, Toronto Hydro took the following actions to identify least regrets investments in the 2025-2029 rate period:

- included additional drivers in its System Peak Demand Forecast (e.g. EVs, data centers and Municipal Energy Plans) to assess the anticipated future demand;
- augmented its decision-making process with the results of a Future Energy Scenarios model to understand the impact of different policy, technology and consumer behavior drivers; and
- used the Future Energy Scenarios to stress-test whether the utility's capacity plan can accommodate energy transition needs (e.g. building heating electrification) in the early part of the next decade, if required.

The Future Energy Scenarios reveal that the impact of building electrification in the next two decades could be significant from a system peak demand perspective, but that there are notable differences (driven by policy, technology and consumer-behaviour choices) as to when and how building electrification could unfold. For example, the Consumer Transformation scenario of the Future Energy Scenario shows that localized consumer-focused technology solutions such DERs (including energy efficiency) could materially curtail the annual peak demand curves in a future where buildings are increasingly electrified. In light of these circumstances, "least regrets" meant Toronto Hydro acted with a higher degree of caution in terms of building new capacity to prepare the distribution grid for wide-scale building electrification in the next two decades, as the policy and consumer-behaviour drivers of this type of demand remain uncertain, and technology advancement could offer more cost-effective solutions in the future. Practically, this meant that Toronto Hydro decided to take a "wait and see approach" to investments in new capacity for accommodating wide-scale building electrification in the mid-2030s and beyond.

Toronto Hydro's "least regrets" investment approach to growth and electrification is reinforced by the utility's Grid Modernization strategy summarized in Exhibit 2B, Section D5.

Toronto Hydro's traditional grid infrastructure is facing a shift driven by renewable energy integration, technology evolution, changing customer needs, and more. The Grid Modernization Strategy recognizes the need to prepare for these 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.

Key elements of this investment strategy include investments in Non-Wires Solutions – such as contracted demand response ("Flexibility Services") and grid-scale renewable-enabling battery energy storage systems ("REBESS") – as well as major investments in the development of 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 operations, provide Toronto Hydro with an enhanced capability 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.

D4.3 Capacity Needs and Investment Plan

As noted above, the primary drivers of capacity need and related investments over the 2025-2029 rate period are: customer connections (included as part of the base forecast), electrification of transit, electric vehicles, hyperscale data centers, and Municipal Energy Plans for three regions of the city discussed above. Figure 4 below shows the contribution of each of these drivers to the System Peak Demand Forecast.

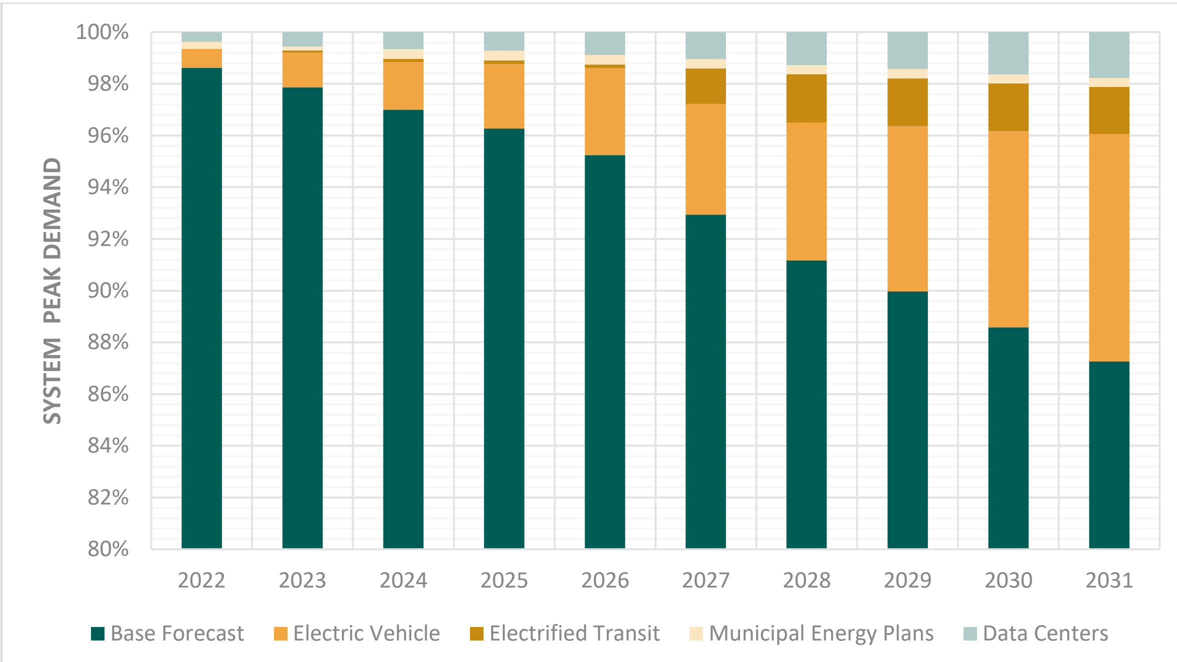


Figure 4: Toronto Hydro System Peak Demand Forecast by Driver

In the development of the System Peak Demand Forecast, Toronto Hydro determined that building electrification (i.e. electrification of space and water heating) is not yet a significant driver of growth in the 2025-2029 rate period. As a result, the System Peak Demand Forecast continues to be a summer peaking forecast. However, to stress test the assumptions regarding building electrification against the least regrets planning philosophy, Toronto Hydro assessed whether the utility could accommodate a growing winter peak (driven by building electrification) in the 2025-2029 rate period if needed. To that end, the utility looked at scenarios of forecasted building heating loads derived from the Future Energy Scenario model outputs. More specifically, Toronto Hydro used the Consumer Transformation scenario, and its low efficiency equivalent, as the lower and upper bounds, of the sensitivity test.

The Consumer Transformation scenario models an energy transition pathway where consumers play a prominent role in driving results towards decarbonization. In addition to high levels of transportation electrification, there are high levels of heating electrification, energy efficiency and DERs. In the related low efficiency Consumer Transformation scenario, the uptake of electrified heat and transport technologies is the same, but the uptake of efficiency measures (e.g. building retrofits), and DERs (e.g. renewables and energy storage) is limited resulting in a higher peak demand. Toronto

Hydro selected the Consumer Transformation scenario and its low efficiency equivalent for this sensitivity analysis because these scenarios presented (i) the most variability in building heat, between the high and low efficiency assumptions, and (ii) the most material grid impact of the energy transition in terms of system peak demand.

Figure 5 below compares the Regional Planning Needs Assessment Forecast, System Peak Demand Forecast and the selected upper and lower bounds of the Consumer Transformation scenario.

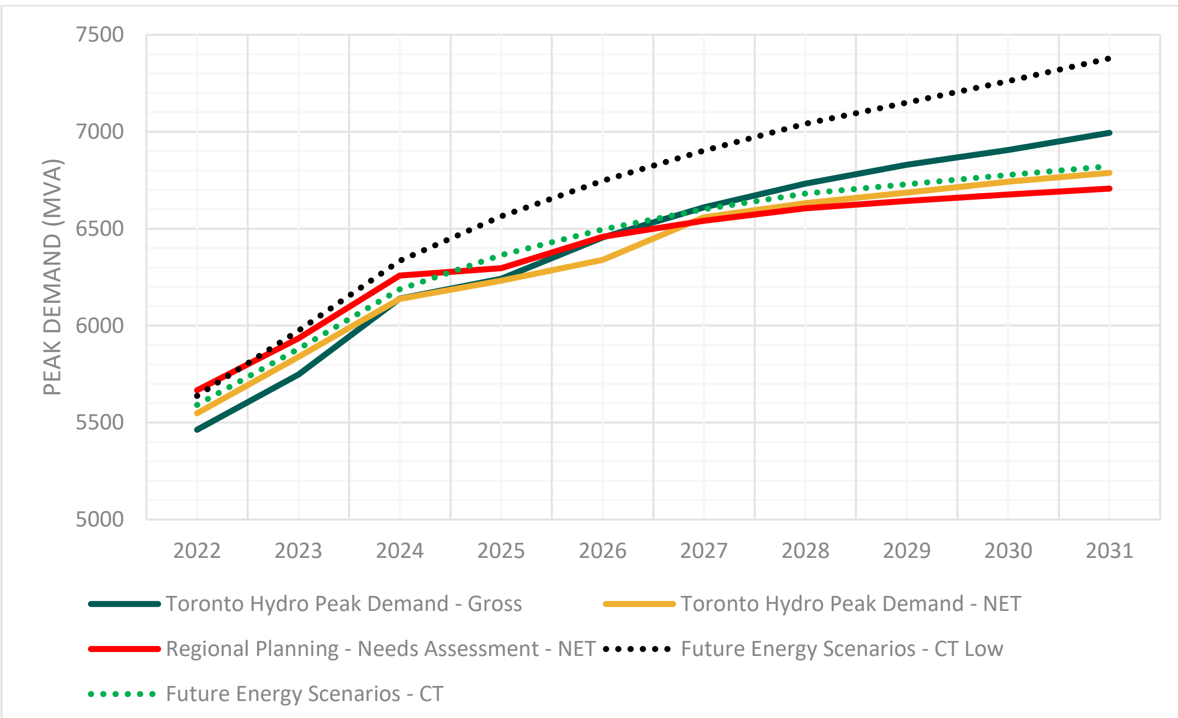


Figure 5: Comparison of Planning Forecasts and Future Energy Scenarios

As shown in Figure 5 above, Toronto Hydro's System Peak Demand Forecast is generally aligned with the Consumer Transformation (CT) scenario. From this analysis, Toronto Hydro concluded that the capacity investment plan can meet higher levels of building heating loads (which contribute to winter peak) should this driver of electrification materialize at a faster pace than expected. As a result, Toronto Hydro has confidence that the investments in system capacity that the utility proposes to make in the 2025-2029 rate period are least regrets to address growth and electrification drivers that the utility faces in this decade and the early part of the next decade. That being said, it is possible that the utility could be faced with incremental capacity constraints at a localized level as a result of accelerated transportation and building electrification demand. To address this challenge, the utility proposes a Demand Related Variance Account to track variances in actual versus forecasted expenditures in a number of demand-related investment programs. For more information about this proposal please refer to Exhibit 1B, Tab 2, Schedule 1.

Based on the capacity planning process outlined above, Toronto Hydro proposes investments in various programs to meet the utility's fundamental obligation to connect new and expanded services to the grid in this decade and beyond. These programs include expansion to increase grid capacity and enhancements to better utilize existing equipment. Through programs such as Load Demand[6], Stations Expansion[7], and Horseshoe and Downtown Renewal[8], Toronto Hydro is renewing and enhancing stations, buses, feeders, and other equipment that will facilitate load growth at the appropriate locations. In areas where Toronto Hydro expects customers to connect more DERs, programs such as Grid Protection, Monitoring and Control alleviate short-circuit capacity constraints.[9] Furthermore, where feasible and cost-effective, Toronto Hydro's intends to leverage the Non-Wires Solutions program to (i) procure market-based flexibility services to avoid or defer capital investment, and (ii) deploy grid-scale storage solutions to enable the connection of renewable energy generation facilities.[10]

The sections that follow discuss in more detail the capacity investments that Toronto Hydro intends to make in key areas of the grid.

D4.3.1 Downtown Area

Figure 6 below shows all transformer stations in the Downtown area. Areas in green represent transformer stations that do not require relief within 10 years. The transformer stations in yellow require bus relief between 5 to 10 years while the transformer stations in red, require bus relief within 5 years.

[6] Exhibit 2B, Section E5.3
[7] Exhibit 2B, Section E7.4
[8] Exhibit 2B, Section E6.2 and Section E6.3
[9] Exhibit 2B, Section E5.5.
[10] Exhibit 2B, Section E7.2.

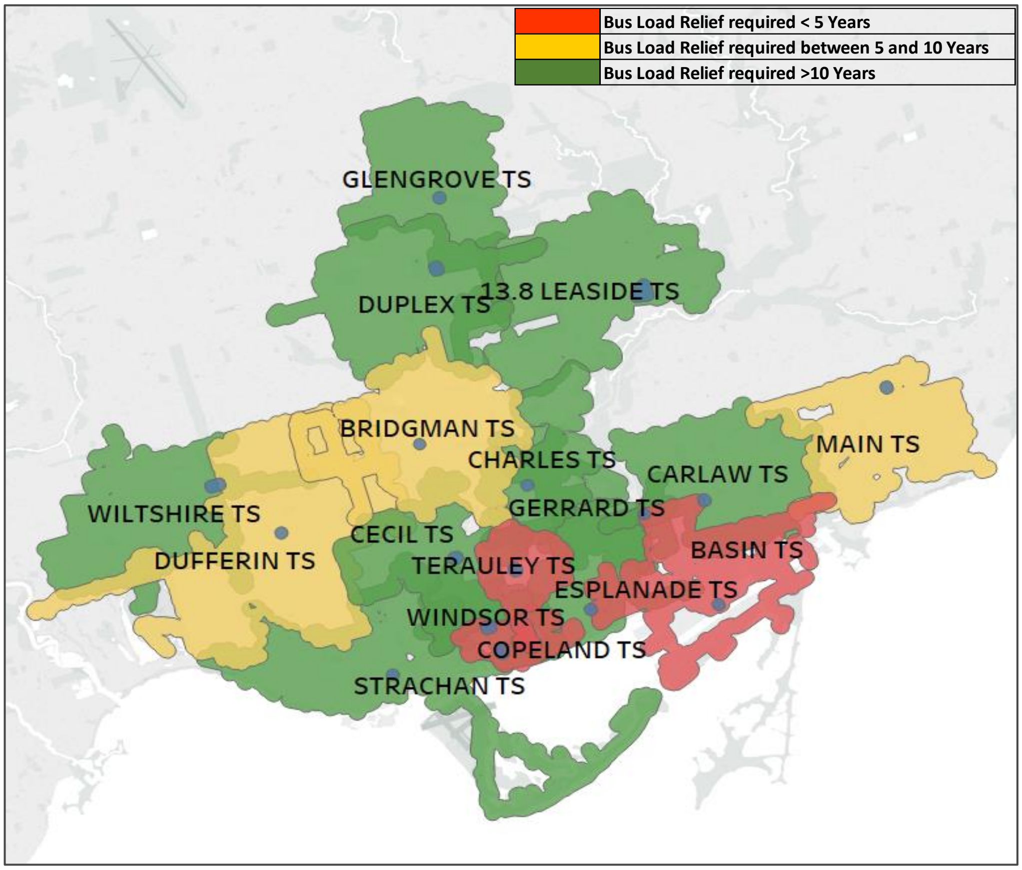


Figure 6: Downtown stations requiring load relief

Toronto Hydro expects that the stations in the south east region of the downtown core will be out of spare feeder positions and become capacity-constrained before the end of the decade, mainly due to the increase in demand from the Port Lands and East Harbour developments.

The Port Lands development is a flood protection project in the southeast of Toronto's downtown core and includes over 715 acres of land along the waterfront. In addition to creating a naturalized river valley for the Don River, this project involves building new public spaces, roads, bridges and municipal infrastructure. Once the flood protection work is complete, development of a planned community on Villiers Island between Cherry Street and Don Roadway is expected to begin.

The East Harbour development, described in the City's Unilever Precinct Secondary Plan, represents 25 hectares of lands located directly to the east of Downtown Toronto. The area is bordered by Lake Shore Boulevard to the south, Booth Avenue to the east, Eastern Avenue to the North and the Don

River to the west. It is also the site of a future rapid transit hub that will accommodate a subway station for the Downtown Relief Line.

The stations most impacted by this growth are the Basin Transformer Station ("Basin TS") and Esplanade Transformer Station ("Esplanade TS"). The Load Demand program addresses capacity limitations at both stations in the short term. Toronto Hydro intends to increase capacity at Basin TS by upgrading existing infrastructure to support the Port Lands and East Harbour Developments and manage near-term capacity shortfalls. The Copeland Phase 2 expansion provides load relief to both Esplanade TS and Basin TS, in addition to alleviate constraints at Copeland TS. For further details please refer to the Stations Expansion program in Section E7.4

D4.3.2 Horseshoe East Area

The Scarborough area in the Horseshoe East experienced significant load growth in recent years, and Toronto Hydro expects this trend to persist due to the development of the Golden Mile corridor, the Ontario Line, and the Scarborough subway extension. In particular, the Golden Mile Secondary Development Plan covers an area of 113 hectares of land in Scarborough bordered by Ashtonbee Road to the north, Birchmount Road to the east, Civic Road / Alvinston Road to the south and Victoria Park Avenue to the west. Taking these drivers into account, Toronto Hydro forecasts average growth of 4.1% per year over the next 10 years in the Horseshoe East Area. To that end, the System Peak Demand Forecast shows that the areas is expected to reach more than 90% of its capacity by 2031. Figure 7 highlights the load relief required in the short term. Toronto Hydro plans to provide capacity relief to the area by expanding Scarborough TS. Please refer to the Stations Expansion Program in Exhibit 2B, Section E7.4 at Appendix B for additional details about this project.

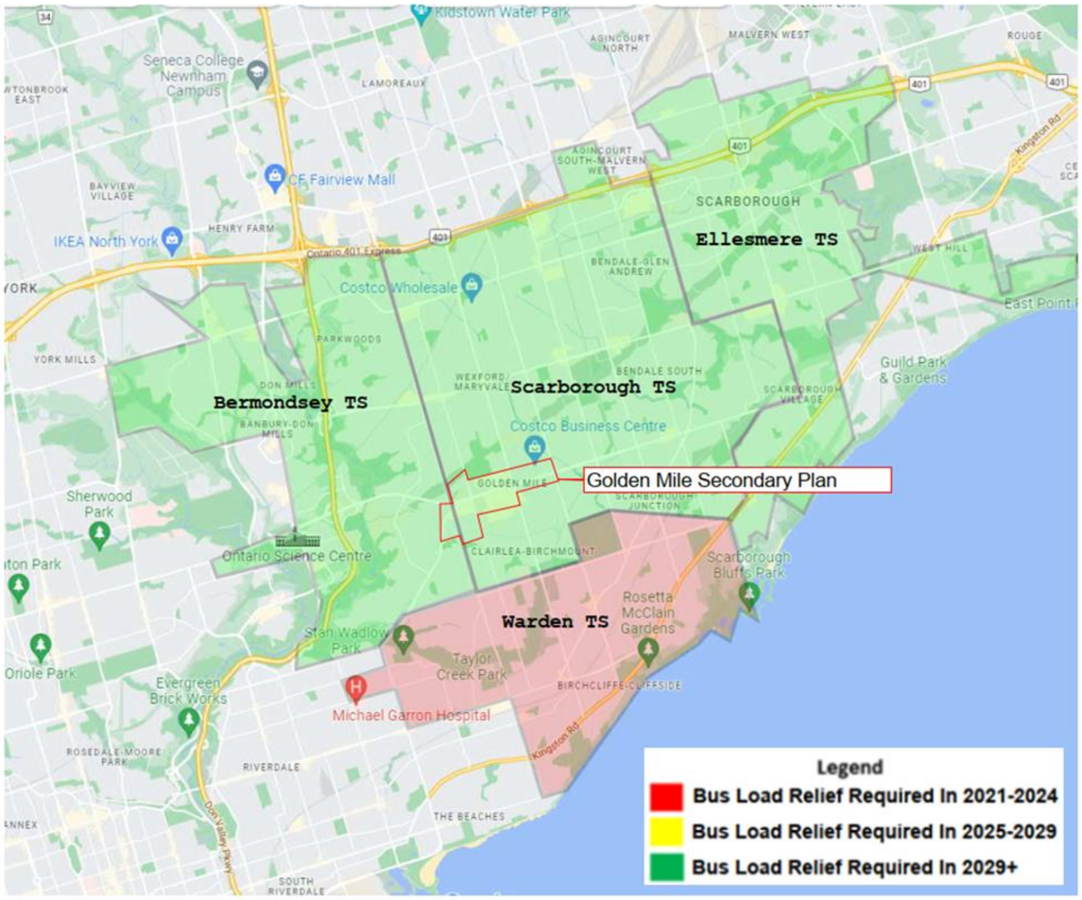


Figure 7: Scarborough TS and East Region

D4.3.3 Horseshoe West Area

The Horseshoe West is also expected to experience notable load growth over the next decade, resulting in a forecasted average peak demand growth of 2.2% per annum. The System Peak Demand Forecast indicates that the majority of stations in this area are expected to reach capacity in the next decade or shortly thereafter. Moreover, by the end of the decade, Toronto Hydro forecasts the entire area to be highly loaded at 90% capacity. The region surrounding the Downsview area (shown in Figure 8 below) is expected to see the highest growth due to redevelopment of this area.

In 2017, the City of Toronto approved of the Downsview Area Secondary Plan, covering 210 hectares, 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 9.

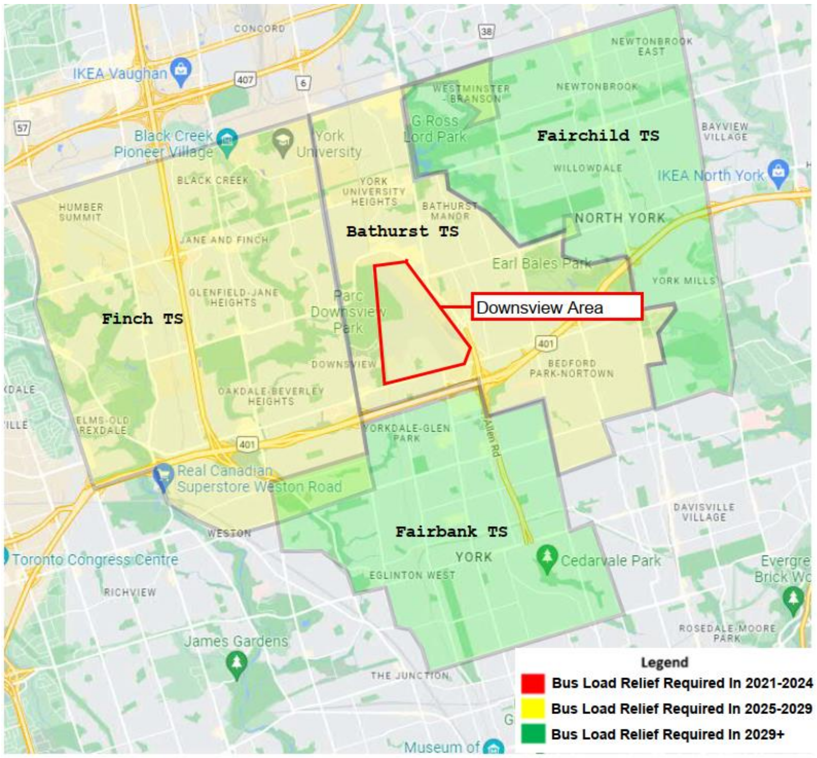


Figure 8: Downsview Area and surrounding stations

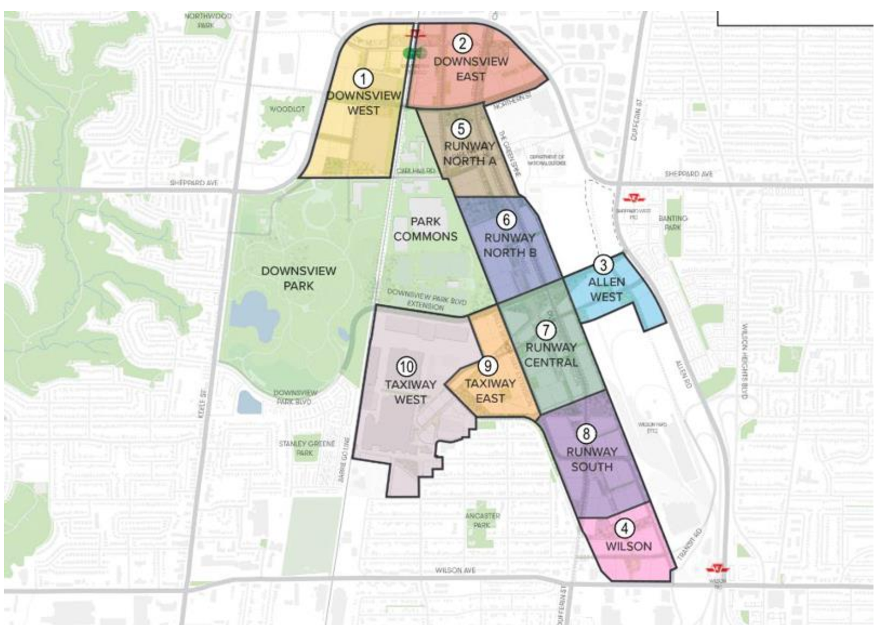


Figure 9: Downsview Area Secondary Plan

The Downsview Area Secondary Plan includes plans to expand each district with a mix of commercial, office, industrial and institutional buildings. The Allen East District is planned for a residential development of approximately 3,500 dwelling units. Load in the Downsview area is expected to reach 103 MW by 2029, 180 MW by 2034, and 509 MW by 2051.[11] Based on this growth, the System Peak Demand Forecast shows that three of the four stations (Bathurst, Fairbank, Finch) in the region surrounding the Downsview Area (Figure 9) are expected to reach their capacity within a short period of one another, in 2030-2036. Fairchild TS is the only station in the region with available capacity (until 2041), but due to geographical constraints, it can only provide direct relief to Bathurst TS.

Load relief is needed at a regional level to support new connections, demand-growth, and electrification in the Horseshoe West area. Through the Toronto Regional Planning process, the utility proposes to construct a new transformer station (Downsview TS) to address this need. Please refer to the Stations Expansion Program at Exhibit 2B, Section E7.4 for more information.

[11] Exhibit 2B, Section E7.4.3.1 – Downsview TS.

Appendix A – Future Energy Scenarios Overview

The energy landscape is undergoing a fundamental shift driven by decarbonization mandates to mitigate the life-threatening impacts of climate change. This shift is expected to create new roles for electricity in the day-to-day energy needs of consumers, including powering transportation and building systems. Toronto Hydro recognizes that the pace and timing of these changes will be driven by a complex interplay of policy, technological developments and consumer choice.

While there is certainty that fundamental change is ahead, there is uncertainty about how that change will unfold (e.g. the pace and adoption of EVs and heat pumps; the role of low emission gas; and the scale of local vs. bulk electricity supply). This reality means that planning is becoming more complex for distributors like Toronto Hydro who must manage various interlinked growth drivers in an environment of greater uncertainty.

Future Energy Scenarios is a modelling tool that explores a range of possible changes to future peak demand based on the interplay of different policy, technology and consumer behaviour assumptions. This scenario-based approach embraces the uncertainty and variability of the energy transition and reveals possible pathways of change.

1 Public Policies and Objectives

Government at all levels are implementing decarbonization policies, including GHG emission targets and incentives to encourage consumers to electrify their transportation and heating needs. Key policies and incentives include:

Canada Greener Homes Grant provides up to $5,000 for electrified heating technologies such as heat pumps.[1] This grant was introduced in December 2020 and is expected to stay in place for seven years.

Incentives for Zero-Emissions Vehicles ("iZEV") program provides up to $5,000 for electric and hydrogen-fueled vehicles until March 2025.[2]

[1] Natural Resources Canada, Canada Greener Homes Grant, "online", https://www.nrcan.gc.ca/energy-efficiency/homes/canada-greener-homes-initiative/canada-greener-homes-grant/canada-greener-homes-grant/23441
[2] Transport Canada, Incentives for Zero-Emission Program, "online", https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/light-duty-zero-emission-vehicles/incentives-purchasing-zero-emission-vehicles

The Ontario Energy Board, working with distributors, recently implemented a **"Ultra-Low Overnight" rate option** to incentivize off-peak EV charging to encourage the uptake of EVs as an alternative to the rising fuel costs of internal combustion vehicles.[3]

Federal Zero Emission Vehicle Sales Targets: The federal government has committed to a mandatory 100% zero-emission vehicle sales target by 2030 for all new light-duty vehicles.[4]

City of Toronto's **Toronto Green Standard** sustainable design and performance requirements for new private and city-owned developments. The most recent version all but eliminates the use of natural gas in new buildings.[5]

Federal carbon pollution pricing system: Since 2019, every jurisdiction in Canada has had a price on carbon pollution, including a charge on fossil fuels like gasoline and natural gas. The fuel charge increases annually in relation to the carbon pollution price. The carbon pollution price will increase from $65 per tonne of carbon dioxide equivalent in 2023 to $170 per tonne by 2030.[6]

Many commercial and industrial customers in Toronto Hydro's service territory have adopted decarbonization and emissions reduction goals through Environmental, Social and Governance ("ESG") mandates. In an engagement with Key Account customers that Toronto Hydro completed in advance of preparing the 2025-2029 investment plan, the utility found that approximately 64% of the customers surveyed have plans to decarbonize their business and expect Toronto Hydro to support them by ensuring that the grid has sufficient capacity to serve their needs.[7]

1.1 Technological Advancements

Technological advancements are providing customers more choice in respect of their energy needs, and over time these choices can have significant impacts for the distribution grid. According the

[3] 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
[4] Transport Canada, Canada's Zero-Emission Vehicle (ZEV) sales targets, "online", https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/canada-s-zero-emission-vehicle-zev-sales-targets.
[5] City of Toronto, Toronto Green Standard, Version 4, "online", https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/toronto-green-standard/.
[6] Government of Canada, How carbon pricing works, "online", https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/putting-price-on-carbon-pollution.html; Government of Canada, Canada Revenue Agency. Fuel Charge Rates, "online", https://www.canada.ca/en/revenue-agency/services/forms-publications/publications/fcrates/fuel-charge-rates.html
[7] Exhibit 1B, Tab 3, Schedule 1 – Customer Engagement p. 18-19.

National Renewable Energy Laboratory's cost benchmarking studies, installed system costs per watt for solar PV from 2010 to 2020 have sharply decreased by 64% for a residential 7-kW rooftop system and 69% for a commercial 200-kW rooftop system.[8] Stand alone battery energy systems (BESS) experienced a similar 10% cost decline from 2020 to 2021.[9] The declining cost curves of these technologies are providing customers more economical choices to invest in distributed energy resources. Similarly, efficiency improvements in heat pumps are making these technologies more feasible alternatives to natural gas furnaces for space heating in cold weather climates.

1.2 Consumer Choices

Consumer choices and behaviors regarding energy use are gradually changing. Activities that previously did not affect the electricity system (including fueling vehicles and space heating) now have the potential to change electricity consumption patterns and shift system peaks. For example, residential and fleet EV charging could create new system needs like real-time voltage control to support a sharp rise from morning and/or afternoon charging on a scale similar to that created by air conditioning demand on hot summer days. Additionally, as heating systems are electrified (e.g. heat pumps), electricity system peaks can shift from summers to winters.

1.3 Future Energy Scenarios Framework

To better understand the challenges posed by the changing energy landscape, Toronto Hydro engaged a leading UK consultant Element Energy,[10] to develop the Future Energy Scenarios modelling tool. This is the first pathway study in Ontario to focus on the distribution-level impacts of the energy transition. The model was informed by a comprehensive investigation into the current state of the energy landscape in Toronto, including reviews of previous studies, data sets and policy. Emissions were not directly modelled in the Future Energy Scenarios, but policies and targets were built into the tool such that the key drivers are consistent with emissions goals.

Future Energy Scenarios employs bottom-up consumer choice and willingness-to-pay models which are based on the concept that consumers try to maximize their utility when making decisions. For example, in the case of different heating technologies, when a homeowner is deciding to replace a

[8] NREL, Solar Installed System Cost Analysis, "online", https://www.nrel.gov/solar/market-research-analysis/solar-installed-system-cost.html. Most cost components relate to capital costs, particularly module and inverter costs, meaning that the decreases apply universally.
[9] Ramasamy Vignesh, David Feldman, Jal Desai, and Robert Margolis. 2021. *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks: Q1 2021.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A40-80694. https://www.nrel.gov/docs/fy22osti/80694.pdf.
[10] Future scenario modelling has been a regular part of system planning by regulated energy utilities in the UK for several years, many of which have been supported by Element Energy.

heating system at the end of its life, they would likely weigh various factors in their decision making, including the upfront cost of different available technologies (e.g. gas-fired furnace, heat pump, hybrid heat pump, etc.), the ongoing operating costs, the complexity of installation, and the suitability of each technology for the property. The bottom-up models in Future Energy Scenarios convert the value of these factors to consumers into equivalent, monetary value or utility, so they can be compared quantitatively.

The outputs of the Future Energy Scenario model are distinct from the capacity planning forecast discussed in Section D4 because they do not predict what is likely to occur in the future. Case in point, the Future Energy Scenarios model does not assign probability to any of the identified scenarios. The Future Energy Scenarios complements the Peak Demand Forecast by enabling Toronto Hydro to explore various pathways and quantify the impacts of those pathways to peak demand. This information is valuable because it allows Toronto Hydro to identify and quantify investments that would be required to reinforce the grid in different scenarios. This capability supports Toronto Hydro's least regrets planning philosophy in that it allows the utility to stress test its Peak Demand Forecast against plausible scenarios to ensure that the utility (1) does not overbuild the system and (2) does not become a barrier to particular decarbonization pathways.

2 Scenario Worlds

The scenario framework captured the range of uncertainties with four main 'scenario worlds' consisting of individual projections for the uptake or pace of various technologies or consumer behaviour. As illustrated in Figure 1 below, each scenario world represents a different energy system pathway oriented on two main axes: speed of decarbonization and level of societal change. These scenario worlds illustrate a view of future energy system changes for a given set of economic, social and policy assumptions. Three of the scenario worlds reach net zero emissions by 2050.

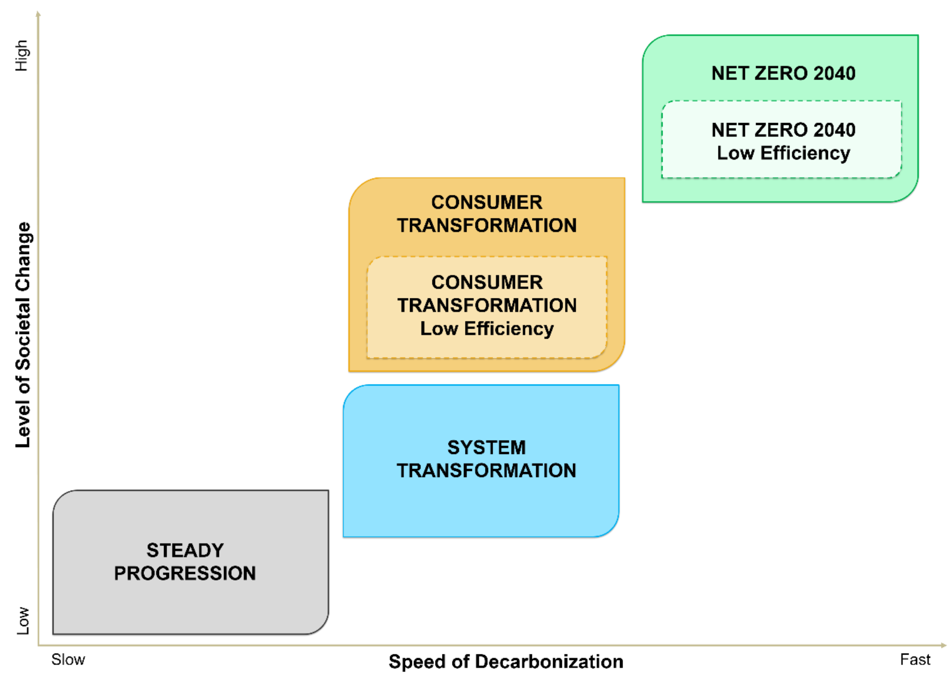


Figure 1: Scenario worlds defined by two axes: speed of decarbonization and level of societal change

The four scenario worlds are structured as follows:

- **Steady Progression** is a low-ambitious electrification scenario that makes general progress towards decarbonization but falls short of the net zero 2050 goal. This scenario reflects minimal consumer behaviour change and is the slowest decarbonization scenario.
- **System Transformation** is a top-down scenario driven by policy-makers. It entails high levels of transportation electrification, but lower levels of heating electrification, energy efficiency and DERs.
- **Consumer Transformation** is a scenario in which consumers play a more prominent role in driving results. In addition to high levels of transportation electrification, there are high levels of heating electrification, energy efficiency and DERs. **"Low Efficiency" Consumer Transformation** is a modified scenario where the uptake of efficiency measures (including building retrofits and DERs) is limited. This sensitivity analysis provides a helpful view into the potential impact of energy efficiency on the distribution grid.

- **Net Zero 2040** is the highest ambition scenario, which is focused on meeting key policy targets early. This scenario aligns with the City of Toronto's TransformTO net zero 2040 goals, and leverages highly ambitious levels of efficiency, electrification, and DERs. **"Low Efficiency" Net Zero 2040** is a modified scenario where the uptake of efficiency measures (including building retrofits and DERs) is limited.

The low efficiency modified scenarios for Consumer Transformation and Net Zero 2040 scenarios couple high electrification with a limited uptake of technologies and strategies which are able to mitigate peak demand growth. These sensitivity analyses provide a helpful view into the potential impact of energy efficiency on the distribution grid, as well as insight into the highest levels of demand that Toronto Hydro's system could face in the journey to decarbonize by 2050.

2.1 Future Energy Scenarios Driver Projections

Each scenario world was constructed by combining uptake forecasts for a number of individual drivers of growth, generation, flexibility and efficiency. Each driver was modelled separately on a Low/Medium/High/Very High basis and then mapped to the scenario worlds. Table 1 shows the calibration of the various drivers for each scenario world. The sections that follow describe the drivers in more detail. For an in-depth explanation of each of the growth driver uptake scenarios, refer to the Future Energy Scenarios report at Exhibit 2B, Section D4, Appendix B.

Table 1: Growth, Generation, Flexibility and Efficiency Drivers within Scenario Worlds

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Net zero by 2050?	No	Yes	Yes		Yes (by 2040)	
Core Demand						
Electrical efficiency	Low	Medium	High	Low	High	Low
Building stock growth	Single Projection					
Low-Carbon Transport						
Cars and light trucks	Low	Medium	Medium		High	
Medium/heavy trucks and Buses	Low	Medium	Medium		High	
Rail	Single Projection					

Parameter	Steady Progression	System Transformation	Consumer Transformation Standard	Consumer Transformation Low	Net Zero 2040 Standard	Net Zero 2040 Low
Smart charging / V2G	Low	Medium	High	Low	High	Low
Decarbonized Heating						
Heat pumps	Low	Medium plus hybrid HPs	High		Early High	
Thermal Efficiency	Low	Medium	High	Low	Very High	Low
Gas heating in 2050	High	Medium due to hybrid HPs	Zero		Zero	
Gas grid availability	Remains at current availability	Reduced utilization	Decommissioned by 2050		Decommissioned by 2040	
Gas grid composition	Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas	Shift to biogas, SNG, or other renewable natural gas	Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas until 2050		Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas until 2040	
Distributed Generation						
Solar PV	Low	Medium	High	Low	Very High	Low
Onshore wind	Low	Medium	High	Low	High	Low
Biogas	Low	Medium	High	Low	High	Low
Other non-renewable generation	High	Medium	Medium	High	Low	High
Battery Storage						
Domestic battery storage	Low	Medium	High	Low	Very High	Low
I&C behind-the-meter battery storage	Low	Medium	High	Low	High	Low

2.1.1 Core Demand

The majority of current electricity demand within Toronto can be categorized as underlying demand from domestic customers and industrial and commercial ("I&C") customers. Underlying demand refers to all electricity usage relating to existing appliances, including electrical heating or cooling, but excludes demand from new low carbon heating technologies such as electric vehicle charging or heat pumps. The latter are modelled as separate segments.

Collectively this underlying demand from these two sectors is referred to as the "core demand". Future core demand for these two sectors is primarily controlled by two key variables:

The total number of customers connected to the system – which is controlled by the size of the building stock (number of buildings); and

The energy intensity of the customers within those properties – which is assumed to be controlled by the uptake and efficiency of customer appliances.

2.1.2 Low-Carbon Transport

Future Energy Scenarios created consumer-choice uptake scenarios for electric vehicles across the following transport segments:

- Light duty battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV);
- Medium and heavy-duty electric vehicles;
- EV buses; and
- Electrified rail.

The low, medium and high scenarios were developed for each vehicle segment based on factors such as vehicle attributes (i.e. price, running cost, performance), consumer attributes (i.e. travel and charging patterns, socio-economic factors), charging infrastructure, and policy and incentives (i.e. grants, carbon tax, phase-out dates etc.).

2.1.3 Decarbonized Heating

Heating is modelled by assessing the business case for various heating technologies across the domestic and I&C building stock types. Future Energy Scenarios considered the following heating technology types in the modelling:

- Traditional fossil-fuel heating technologies (natural gas boiler, natural gas furnace, oil and LPG burners and coal burners);
- Air source heat pump;

- Ground source heat pump;
- Hybrid heat pump;
- Biomass furnace/boiler, and
- Electric heater.

Uptake and efficiency of the heating technologies is varied across the scenarios to represent the possible futures depending on costs, incentives, thermal efficiencies, technological development, and consumer behaviour.

2.1.4 Distributed Generation, Storage, and Flexibility

A broad range of distribution-level generation, storage, and flexibility technologies were considered as part of Future Energy Scenarios. Figure 2 below depicts the total set of technologies modelled. For each technology, four scenarios were developed (low, medium, high, and very high) to include the range of possible future scenarios. Based on technology suitability, system needs, supporting policies, and financial incentives, there are three dominant generation technologies for Toronto: solar PV (both rooftop and ground-mounted), non-renewable generation, and energy storage.

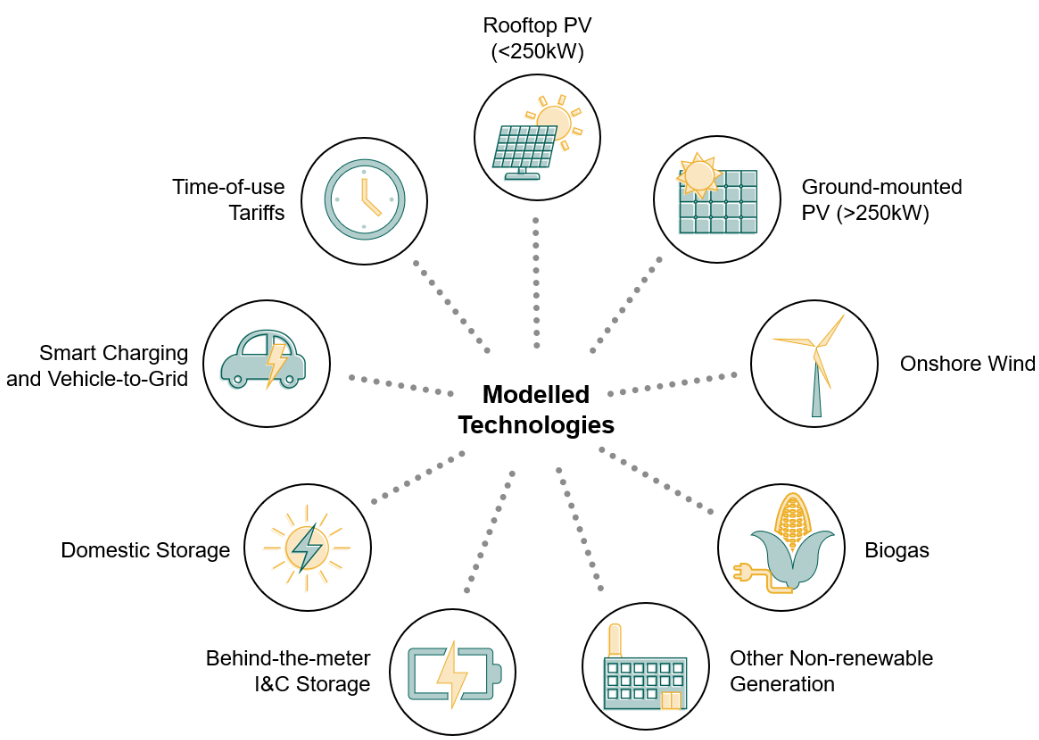


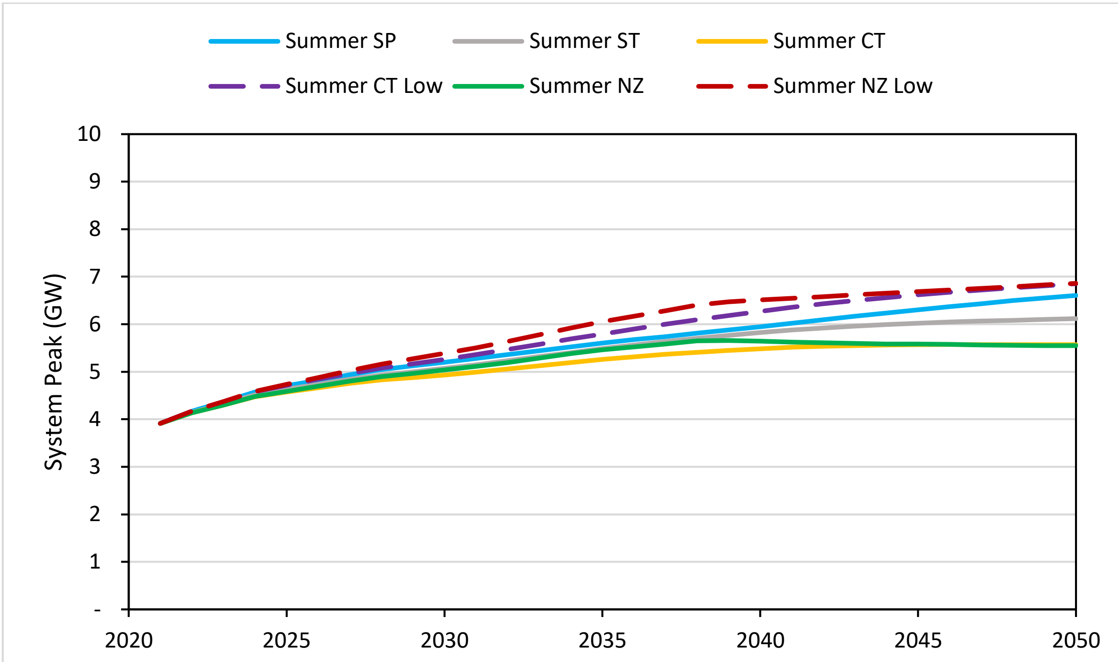
Figure 2. Distributed Generation, Storage, and Flexibility Technologies

2.2 System Impacts

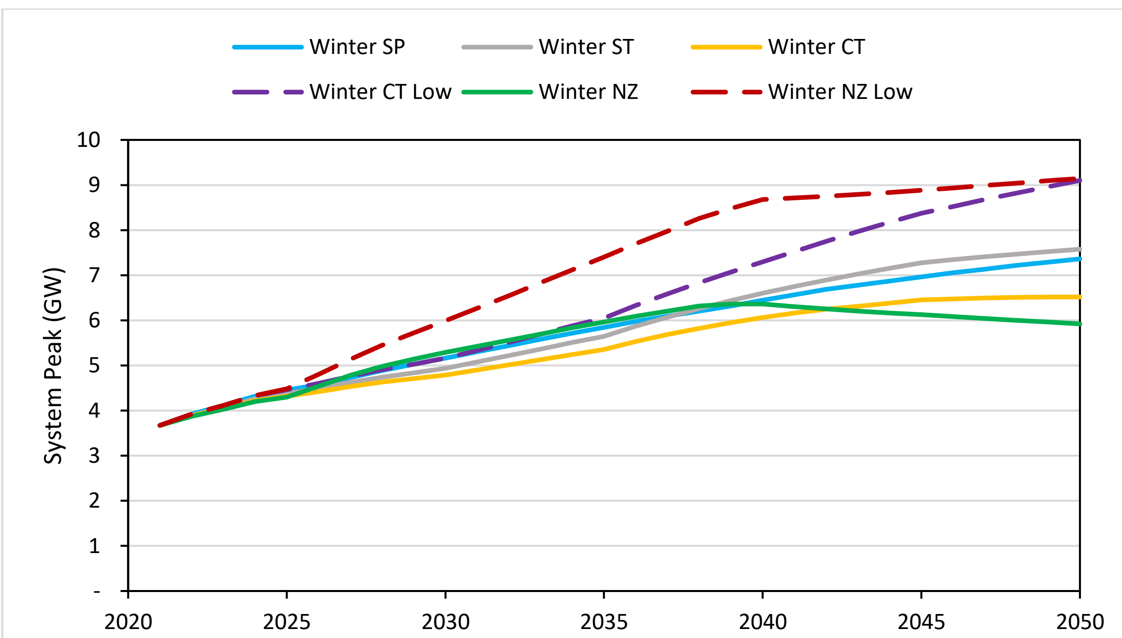
The projected trends in technology adoption spanning energy demand, generation and storage in the Future Energy Scenarios were used to determine the associated load impacts across Toronto Hydro's distribution system.

The Future Energy Scenarios datasets were loaded into the model to create projections for the changing demand and generation on the system out to 2050. In order to provide a complete picture of the potential changes on the system, the Future Energy Scenarios model projects the annual consumption and peak electricity demand for the system's 88 terminal station bus pairs, as well as the total across all of Toronto Hydro's service area. In addition to producing the total peak demand for each asset, the model can also show the contribution of each technology to the peak. This enables a more complete understanding of the drivers behind changes in loading across the distribution system.

Figures 4 and 5 show the resulting peak system load for Toronto Hydro. The two most ambitious decarbonization scenarios (Consumer Transformation and Net Zero 2040) have the lowest peak demands by 2050 when the full benefits of appliance and building fabric efficiency measures, demand side flexibility, and renewable generation are realized. In the absence of these benefits being realized, the system peak loads by 2050 would be significantly higher, as illustrated by the two dashed lines for Consumer Transformation Low and Net Zero 2040 Low shown in Figures 3 and 4. The Low Efficiency scenario worlds are critical for considering Toronto's energy future, as they illustrate that a material reduction in peak demand can be achieved through the ambitious deployment of passive efficiency measures, renewable generation and active demand management.



1 **Figure 3: Summer System Peak for Scenario Worlds**



2 **Figure 4: Winter System Peak for Scenario Worlds**

3 Future Energy Scenarios – Key Takeaways

The Future Energy Scenarios confirms that Toronto can expect significant changes to its energy system resulting from electrification, renewable generation deployment, and improvements in energy efficiency. Peak demand increases are expected to be primarily driven by the electrification of the heating and transport sectors, due to the widespread uptake of technologies such as electric vehicles and heat pumps.

The nature of load changes on the distribution system varies considerably over the modelled time period. In the 2020s, electricity load growth is very similar across all scenario worlds, indicating that reinforcement is likely to be required regardless of the what pathway of decarbonization is chosen by consumers or governments. The 2030s sees the system peak shift to winter with loads increasingly being driven by heat pump uptake and EVs. In this decade, load growth also starts to diverge across the scenario worlds, highlighting the need for early planning and capacity investments to ensure the distribution system is prepared for both near-term and long-term energy system changes.

The Future Energy Scenarios also highlight the need for changes to generation, storage, and energy efficiency to happen in parallel with electrification of demand. All of the core scenario worlds assume that efficiency improvements increase significantly from the present day, continuing to reduce energy consumption in future years. Without such changes, grid demands are expected to increase more extremely, as demonstrated by the two “Low” scenario worlds shown in Figures 3 and 4.

Future Energy Scenarios

Report for Toronto Hydro by

Element Energy, an ERM Group company

30th May 2023

elementenergy
an ERM Group company

ERM

TORONTO HYDRO

Executive Summary

Introduction

The complexity of distribution system load forecasting is increasing significantly due to factors such as decarbonization, decentralization, digitization, changing customer behaviours and evolving economic and policy conditions. Significant changes in demand, generation and flexibility on electricity distribution networks are affecting network management and planning. New demands emerging from the electrification of heat and transport, growing levels of distributed generation (including variable renewable generation) and new sources of load flexibility (including energy storage) mean that local electricity distribution companies, such as Toronto Hydro, are facing increasing levels of uncertainty.

Element Energy, an ERM Group company, is a leading low carbon energy consultancy with considerable experience in supporting electricity distribution businesses, particularly in relation to their future energy scenario planning and load projections. Through extensive previous work in this area, Element has developed a modern, state-of-the art tool known as the Future Energy Scenarios (FES) Model. This tool is in active use across various electricity distribution companies and, as such, is fully equipped with the latest innovations in the field. The FES model has a strong track record of active use within the industry, including for the creation of various statutory outputs and reports under the scrutiny of the relevant energy regulators due to its base in robust modelling methodologies.

This report presents the Future Energy Scenarios prepared by Element Energy for Toronto Hydro and is the first of its kind for distribution companies in Canada. The Future Energy Scenarios provide an overview of possible future changes to power demand, energy consumption, generation and storage across Toronto and an assessment of their potential impacts on the Toronto Hydro electricity distribution network. This is predicated upon a highly granular consumer choice-based analysis of future loading conditions at each individual transformer station bus, providing a strong evidence base for network planning and the evaluation of future infrastructure investments. This establishes a common strategic outlook to support forecasting needs across different Toronto Hydro business functions and various stakeholder engagement and regulatory reporting requirements.

The report first provides an outline of the scenario framework used for the Future Energy Scenarios and introduces the concept of 'scenario worlds'. This is followed by an overview of the modelling methodology, focusing on the consumer choice models utilized by Element Energy. Next, the report details how these models were used to develop future uptake scenarios for each of the drivers of demand and generation considered in the FES Model. These drivers include, for example, electric vehicles (EV), energy efficiency measures and solar photovoltaic (PV) installations. Following this, the methodology for modelling the network impacts of these changes is introduced and key results are presented. Finally, the report presents the conclusions drawn from this work.

Scenario Framework

Projections were developed using Element Energy's suite of bottom-up consumer choice and willingness-to-pay models. These were informed by a comprehensive investigation into the current state of the energy landscape in Toronto, including reviews of previous studies, datasets, and policy. To capture the range of uncertainties in a coherent and meaningful way, four main 'scenario worlds' were developed, consisting of individual projections for different technology sectors. The scenario worlds represent different energy system pathways, three of which reach net zero emissions by 2050, and illustrate the best view of future energy system changes for a given set of economic, social and policy assumptions. At a high level, the four scenario worlds differ in terms of the speed of decarbonization and level of societal change they represent, as illustrated by Figure 1.

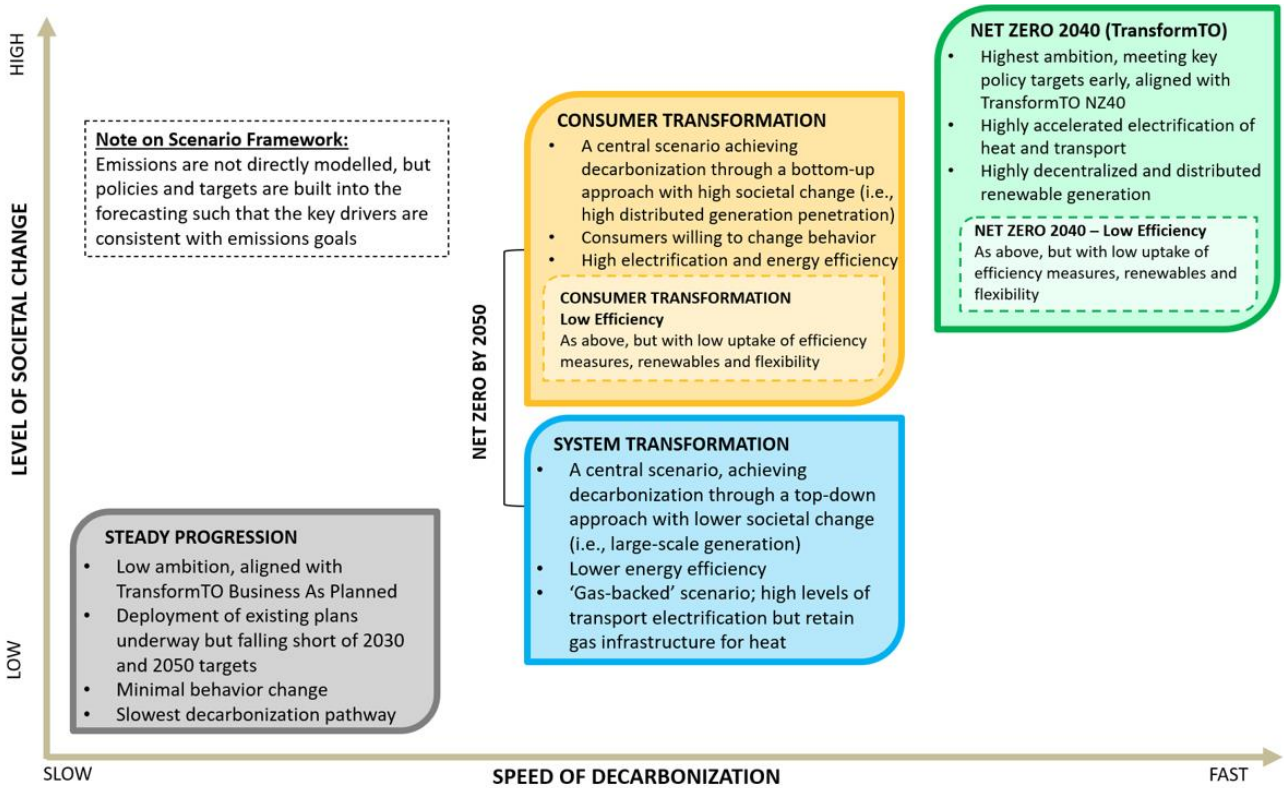


Figure 1: Scenario worlds defined by two axes: speed of decarbonization and level of societal change.

Each of the four scenario worlds consist of a unique combination of uptake trends for all the individual drivers of demand and generation in Toronto, such as electric vehicles, heating, solar PV and core demand. Element Energy's bottom-up consumer choice models produced three to four scenarios for every demand and generation driver, representing a range of possible futures for each technology. Based on the assumptions contained within them, these were then mapped to the overarching scenario worlds shown in Figure 1, so that each scenario world contains one scenario per technology.

The scenario worlds used in this work were developed through an assessment of existing sources that focus on the future of low carbon technologies in Canada[1], Ontario[2], and Toronto[3], as well as through engagement with Toronto Hydro's internal and external stakeholders. The most significant of the existing sources was TransformTO, the climate action strategy developed by the Toronto City Council, which similarly defines four scenarios of varying levels of ambition, including targets to be achieved in key sectors such as buildings, transportation, and generation. In contrast to the consumer choice-based modelling employed in the Future Energy Scenarios presented in this report, the development of the TransformTO scenarios placed a more explicit focus on greenhouse gas reduction, looking at the overall requirements necessary to meet local decarbonization targets. The TransformTO scenarios were used as a reference point to define the overall level of ambition modelled in the four Future Energy Scenario worlds shown in Figure 1. The *Business as Planned* scenario from Transform TO was used as a template for the lower ambition *Steady Progression* scenario world, which involves progressing with existing plans for decarbonization and sees some level of emissions reduction without reaching net zero by 2050. The *Net Zero 2050* scenario from Transform TO was used as a basis for the two central scenario worlds, *Consumer Transformation* and *System Transformation*, both of which reach net zero by 2050 but vary in levels of societal change and electrification. Finally, the TransformTO *Net Zero 2040* scenario was the foundation for developing the highest ambition scenario world which sees significant levels of electrification, behaviour change and efficiency.

[1] CER, Canada's Energy Future, 2021
[2] IESO, Annual Planning Outlook, 2022
[3] City of Toronto, TransformTO, 2021

Using this approach, the scenario worlds were able to capture local considerations of the energy transition that are specific to Toronto, whilst leveraging a robust and proven framework for network planning and load modelling. The four scenario worlds are structured as follows:

1. **Steady Progression:** Some progress is made towards decarbonization; however, this is the only scenario world that does not meet net zero by 2050.
2. **System Transformation:** The 2050 net zero target is met through a top-down approach with lower societal change and retention of the gas grid for biogas and renewable natural gas (RNG).
3. **Consumer Transformation:** The 2050 net zero target is met by a high degree of societal change as well as deep electrification of transport and heat in the standard scenario world.
    - **"Low Efficiency" sensitivity** – the uptake of electrified heat and transport technologies is the same as in the main Consumer Transformation world, but in this sensitivity the uptake of efficiency measures (building fabric & appliance), flexible technologies such as battery storage, and distributed renewable generation is limited.
4. **Net Zero 2040:** This is the fastest of the scenario worlds to achieve net zero, with the most ambitious level of societal change, utilizing both biogas and electric low-carbon technologies.
    - **"Low Efficiency" sensitivity** – Similar to the Consumer Transformation sensitivity described above, in this sensitivity the uptake of demand technologies is the same as in the main Net Zero 2040 world, but the uptake of efficiency, flexibility and distributed renewable generation is limited.

The low efficiency sensitivity cases described above for the Consumer Transformation and Net Zero 2040 scenarios couple high electrification with a limited uptake of technologies which are able to mitigate peak demand growth, and therefore provide insight on the highest loads which might be expected on Toronto Hydro's network to 2050.

Modelling Framework

The Future Energy Scenarios capture potential changes across a broad range of key sectors that are expected to impact upon network load. As described above, the projections were created using Element Energy's technology specific bottom-up consumer choice and willingness-to-pay models, which are based on a rigorous understanding of underlying technology costs, consumer behaviour and wider energy market drivers. In building these consumer choice models, historic deployment rates of technologies are analyzed to determine uptake levels, which are used to calibrate the model.

Where consumer choice modelling is applied within the Future Energy Scenarios, discrete choice modelling[4] is utilized. This is based on the concept that consumers try to maximise their 'utility', which is a monetized indicator representing the value of a technology to a consumer. Discrete choice models assess the perceived value to consumers of a range of competing technologies.

For example, in the case of different heating technologies, homeowners have to make a decision when replacing their old heating technology (e.g. a gas furnace) at the end of its life with a new technology (e.g. a heat pump, an electric heater or a new gas furnace). When making this decision, a customer would likely consider various factors including the upfront cost of the technologies, their running costs, the complexity of installation and the suitability of each technology for their property before reaching a decision. Discrete choice models convert the value of these factors to consumers into an equivalent monetary value, or 'utility', so that they can be compared quantitatively. This process is shown in Figure 2.

[4] Kenneth E. Train, Discrete Choice Methods with Simulation, 2002

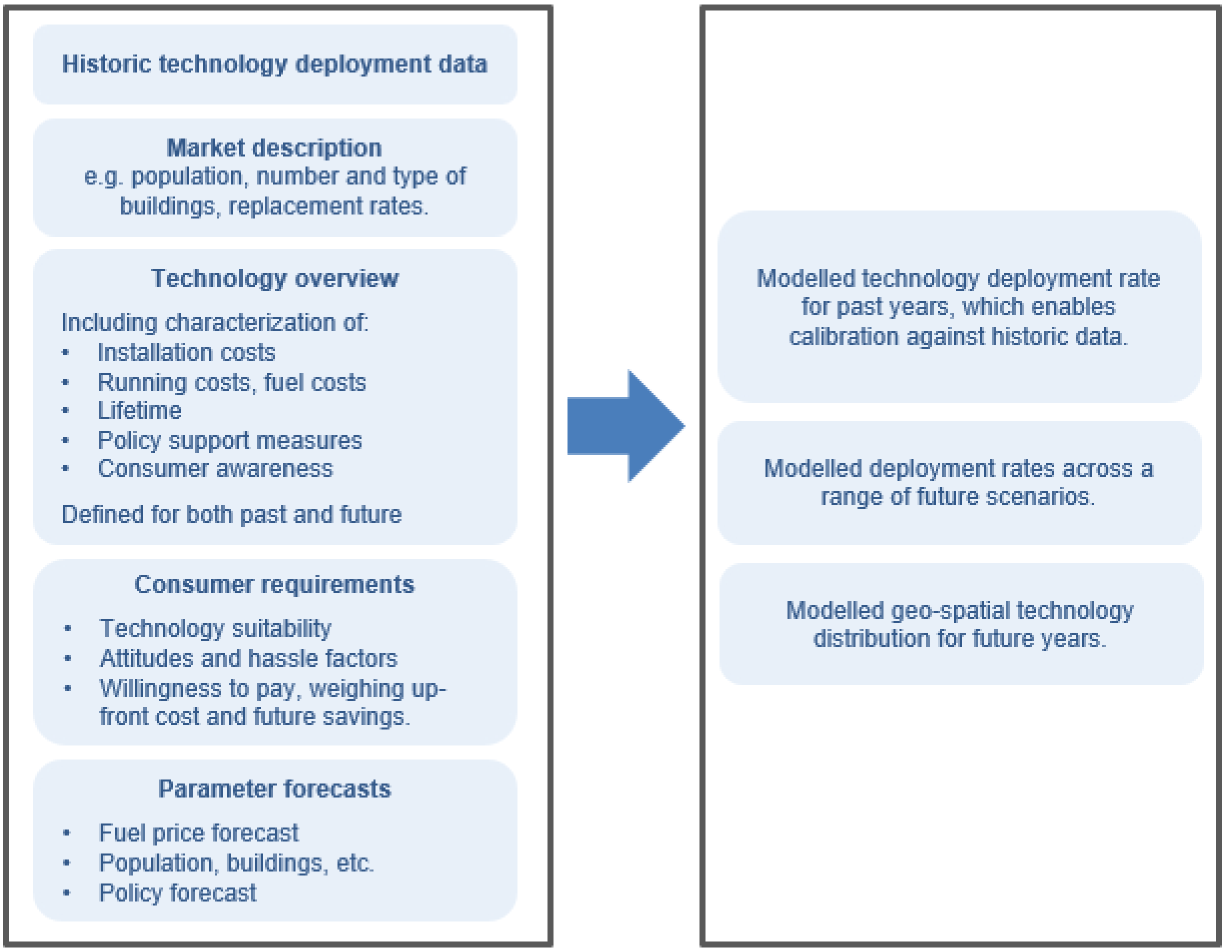


Figure 2: General approach to modelling future technology deployment.

The consumer choice models utilized in this work have been tailored to Toronto Hydro's network area to take into account specific local factors, such as policy measures (e.g. the Canada Green Homes Grant) and the breakdown of vehicle stock. Additionally, the modelling considers local geography when distributing demand and generation across the region, such as a detailed look at potential electric vehicle charging locations.

Development of Demand and Generation Driver Projections

Modern electricity networks supply energy to homes and businesses to service a broad range of applications. In this analysis, the electricity provided for most conventional applications is referred to as "core demand". At present, the majority of energy used for both transport and space heating is derived from non-electrical energy vectors (such as gasoline and diesel for transport, or natural gas for space heating). As part of the decarbonization of transport and space heating, there is potential for a significant level of electrification to occur across these sectors making them particularly important areas of analysis for electricity network planning and load modelling. As such, transport and space heating are each modelled separately to "core demand" in this analysis to support a more detailed understanding of potential future demands from these technology segments.

Similarly, increasing levels of distributed electricity generation (e.g. from solar PV, wind, etc.) also play an important role in modelling future loading across electricity networks as net zero strategies are implemented. Hence this analysis also explores the impact of distributed generation from a variety of technology options on future network loads under a range of scenarios.

As the energy provision of the distribution network grows due to factors such as the electrification of heat and transport as well as increasing distribution electricity generation, the peak instantaneous power demand experienced by the network generally also increases. To help reduce the amount of network reinforcement required to accommodate increases in peak demands across the electricity network, several flexibility options exist which help to move demand at peak times to different times of the day. This analysis captures the impact of flexibility options such as energy storage as well as smart charging and vehicle-to-grid (V2G) options for electric vehicles. Energy storage is modelled as a distinct technology segment which can help to shift peak power loads by charging when demand is low and discharging when demand is high. Similarly, smart charging and V2G chargers can help to shift loads from EVs. Respectively, these act by managing when car batteries charge and enabling cars to discharge to the network at times of high demand, effectively acting as grid storage units. Without such management of charging, the demand from electric vehicles typically spikes during times of high network demand, contributing to high overall peaks at an asset and system level. Charging flexibility measures are captured within the modelling of transport demand by assuming different uptakes of smart charging and V2G in each scenario, and applying distinct load characteristics for each type of charging behavior.

The key sectors investigated in this analysis were core demand, heating, transport, generation, and energy storage via 17 unique technology segments and 72 different customer archetypes or classes. Analysis of each technology segment was carried out to a high level of geo-spatial granularity in order to assess the impact on each of the 88 individual transformer station buses selected for analysis within Toronto. Demand increases are expected to be driven primarily by the heating and transport sectors as a result of widespread electrification via the uptake of technologies such as EVs and heat pumps. Renewable generation projections in Toronto are dominated by solar PV, while energy storage is anticipated to play a role in domestic, industrial and commercial settings.

Load impacts of the demand, generation and storage sectors discussed above are aggregated to determine the total energy consumption and peak demand for each individual asset. This facilitates an assessment of when each asset may exceed its rated capacity, and by how much. This is a critical process for informing network planning and allowing Toronto Hydro to assess the costs and timescales of possible future infrastructure upgrades.

The modelling used to generate the Future Energy Scenarios for Toronto Hydro also highlights the importance of government policies in helping to achieve the relevant net zero targets in each case and further details of the illustrative policy assumptions that were utilized for each of the technology uptake projections are included in this report. The models used throughout the analysis can be updated to reflect future policy developments and market changes which will influence the uptake of low carbon technologies.

Network Impacts

The projected trends in technology adoption spanning energy demand, generation and storage in the Future Energy Scenarios were used to determine the associated load impacts across the Toronto Hydro distribution network.

The Future Energy Scenarios datasets were loaded into Element Energy's FES Model to create projections for the changing demand and generation on the network out to 2050. In order to provide a complete picture of the potential changes on the network, the FES model projects the annual consumption and peak electricity demand for the 88 assets on the network as well as the total across all of Toronto Hydro's service area. In addition to producing the total peak demand for each asset, the model can also show the contribution of each technology to the peak. This enables a more complete understanding of the drivers behind changes in network loading across Toronto.

The load modelling process used by the FES Model can be divided into four main calculation stages as illustrated in Figure 3: technology counts; annual consumption and generation; profile shapes and peak demand; and scaling calibration.

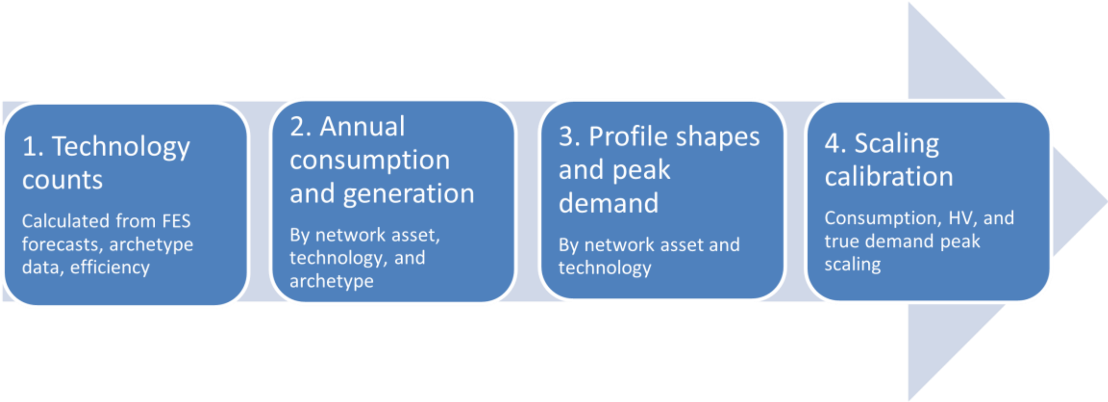


Figure 3: The main stages of the load modelling process.

Technology counts define the quantity of each technology in a given year, and their distribution across the network; in the cases of generation and storage technologies, these figures are given in terms of connected capacity rather than number of units. These figures are used, along with data regarding the characteristics of each technology, to calculate the energy consumption and generation values (MWh) each year. Peak power demand and generation (MW) is subsequently established through the application of load profiles, which describe how the energy consumption/production of each technology is distributed across the year, defined for each month at a half-hourly resolution (Figure 4). Finally, the scaling step calibrates modelled results by aligning them with real network load data for the base year provided by Toronto Hydro.

Applying load profiles to annual consumption shows how power demand for each technology varies across every modelled year. These power demands can then be summed across all relevant technologies to find the overall demand at every transformer station bus at any given time of day across the year. From this, the peak demand can be determined by extracting the maximum power value from any given year. A similar process is performed to find system peak, whereby the power demand from each asset is aggregated and the maximum value is again extracted. Load profiles are also used in the FES model to capture the impacts of flexibility measures. For example, the FES model applies distinct load profiles for smart charging and V2G that reflect how electric vehicles are able to shift charging demand away from times of peak load.

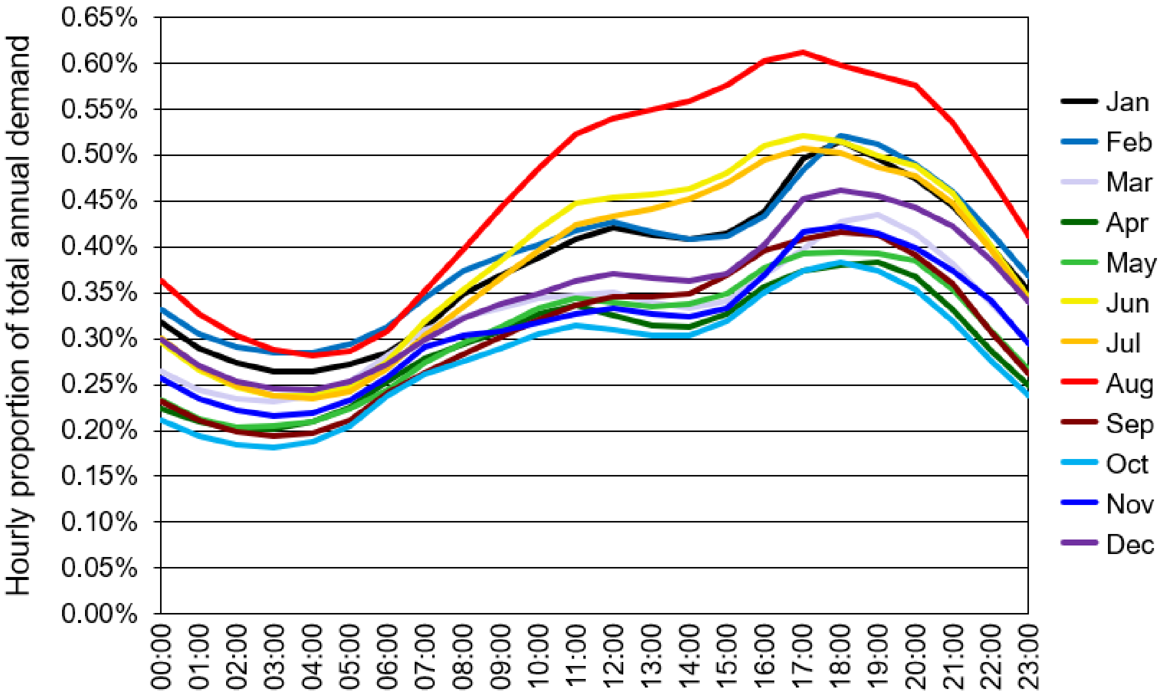


Figure 4: Example load profile: load profiles for domestic core demand.

The resulting peak network load for Toronto Hydro is shown in Figure 5, which illustrates how the two most ambitious decarbonization scenarios (Consumer Transformation and Net Zero 2040) have the lowest peak demands by 2050 when the full benefits of appliance and building fabric efficiency measures, demand side flexibility and renewable generation[5] are realised. If this is not the case, the network peak loads by 2050 are expected to be significantly higher, as illustrated by the two dashed lines for Consumer Transformation Low and Net Zero 2040 Low shown in Figure 5. The Low Efficiency scenario worlds are critical for considering Toronto's energy future, as they illustrate that a material reduction in absolute peak demand can be achieved through the ambitious deployment of passive efficiency measures, renewable generation and active demand management. This demonstrates the potential to avoid significant reinforcement costs and disruption throughout Toronto Hydro's network while pursuing decarbonization.

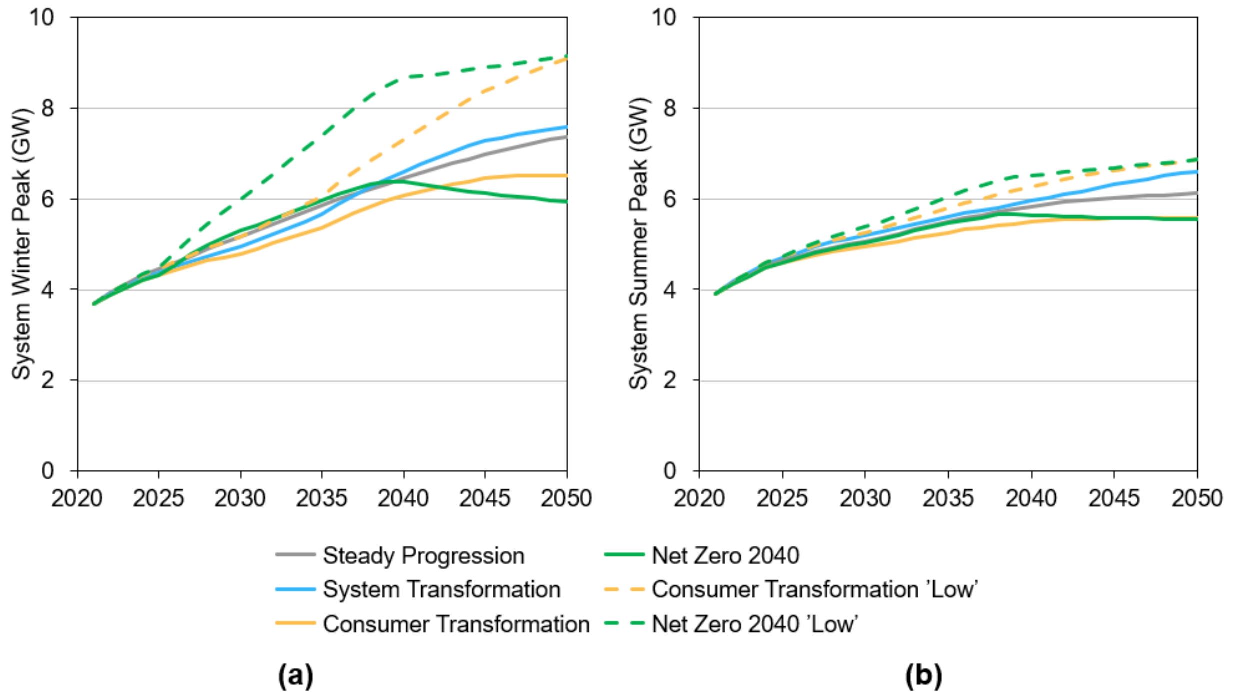


Figure 5: Network peak true demand in (a) winter and (b) summer in the four scenario worlds and two sensitivity scenarios.

In the base year, peak loads are expected to be higher in summer (3.9 GW) than in winter (3.7 GW), primarily due to high levels of air conditioning demand which constitutes a large portion of base core demand. In the 2020s, the network level load follows a similar trend in all scenario worlds, driven primarily by the connection of high voltage loads and uptake of electric heating. The 2030s see the time of network peak shifting to winter, with loads increasingly being driven by heat pump uptake and electric vehicles. As these technologies become more established, they are adopted in large numbers, especially in the more ambitious net zero compliant scenarios. These trends continue into the 2040s; however, increasing electricity demands are moderated by the uptake of renewable generation and storage, which also see an accelerated growth in the later years. The impact of efficiency measures is assumed to increase at an approximately constant rate over the full modelled timeline, with the more ambitious scenarios seeing a more rapid acceleration in the early years, followed by diminishing improvements in later years.

[5] Figure 5 shows the network-level peak *true demand* (i.e. gross), and so only the effect of behind-the-meter renewables (such as rooftop solar) would be seen in this plot. The sensitivity scenarios consider low uptake of both behind-the-meter and utility scale distributed generation.

Conclusions

This work has found that Toronto can expect significant changes to its energy system resulting from electrification, renewable generation deployment, and improvements in energy efficiency in every modelled scenario world. Peak demand increases are expected to be primarily driven by the electrification of the heating and transport sectors, due to the widespread uptake of technologies such as electric vehicles and heat pumps. For example, in all net zero compliant scenario worlds, the transport sector sees a full transition to electric vehicles across all vehicle types. Similarly, all domestic, commercial and industrial buildings are expected to derive heat from some form of electrified technology by 2050 in all of the net zero compliant scenario worlds.

The nature of load changes on the distribution network is expected to vary considerably over the modelled time period. In the 2020s, electricity load growth is very similar across all scenario worlds, indicating that reinforcement is likely to be required regardless of the chosen decarbonization approach. This highlights the need for early planning to ensure the distribution network is well-prepared for near-term energy system changes.

In the 2030s, uptake of electric vehicles and heat pumps begins to accelerate, causing a shift in the time of network peak from summer to winter. In the later years, the high peak demands caused by the electrification of heat and transport are moderated by the uptake of renewable generation and storage, which see accelerated growth in the 2040s. Future generation uptake is anticipated to be dominated by solar photovoltaics, which in some cases may be accompanied by domestic battery storage systems. Uptake of batteries by industrial and commercial customers is also expected to increase, helping to further alleviate grid constraints.

Another significant outcome of this work is the identification of the need for changes to generation, storage, and energy efficiency to happen in parallel with electrification of demand. All of the core scenario worlds assume that efficiency improvements increase significantly from the present day, continuing to reduce energy consumption in future years. Without such changes, grid demands are expected to increase more extremely, as demonstrated by the two sensitivity scenario worlds shown in Figure 5. These pathways would necessitate significantly higher levels of investment to upgrade assets across the network, showing the value of efficiency measures and demand flexibility.

Toronto Hydro's Future Energy Scenarios also highlight the importance of policy as a powerful tool in shaping the energy system. For example, in the low carbon heat uptake trends, the dominant factors in determining the uptake trajectories were the various assumptions regarding fossil fuel bans and financial incentives for cleaner technologies. This is of particular relevance as the Future Energy Scenarios demonstrate that policy support will be essential to the attainment of a 2040 or 2050 net zero target. There are many factors that can influence this at all levels of the energy system, but the modelling shows that policy is one of the higher impact options for accelerating the pace of change.

All scenarios modelled indicate a significant increase in peak demands across the Toronto Hydro network relative to current levels, highlighting the importance of early planning and preparation for the anticipated changes this will involve for the network. Figure 5 illustrates that the extent by which peak demands will increase across the network, particularly beyond 2030, is dependent on the pathway via which net zero targets are achieved. Further, the sensitivities applied to Consumer Transformation and Net Zero 2040 demonstrate the importance of efficiency measures, renewable generation and flexible demand technologies in limiting peak demand growth. Therefore, maintaining an up-to-date understanding of the latest government policies, technological advancements, evolving supply chains and changing consumer attitudes is crucial for planning the low-carbon energy transition. Regularly updating network projections with the latest available data and learnings is important for anticipating changes in technology deployment levels and the implications this will have for network planning as we transition to a low carbon future.

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Acronyms

AC	Air conditioning
ASHP ATA	Air-source heat pump: air-to-air
ASHP ATW	Air-source heat pump: air-to-water
BAP	Business as Planned (TransformTO Scenario)
BEV	Battery electric vehicle
BNEF	Bloomberg New Energy Finance
CDM	Conservation and Demand Management
CGA	The Canadian Gas Association
ECCo	Element Energy's Electric Car Consumer Model
EV	Electric vehicle
FES	Future Energy Scenarios
GSHP	Ground-source heat pump
HV	High voltage
Hybrid ASHP	Hybrid air source heat pump
I&C	Industrial and commercial
ICI	Industrial Conservation Initiative
IESO	The Independent Electricity System Operator
LDC	Local distribution company
LPG	Liquified petroleum gas
NAICS	North American Industrial Classification System
NZ40	Net Zero by 2040 (TransformTO Scenario)
OEB	Ontario Energy Board
PHEV	Plug-in hybrid electric vehicle
PV	Photovoltaic
RPP	Regulated Price Plan
RNG	Renewable natural gas
SUV	Sports utility vehicle
ToU	Time-of-Use
TTC	Toronto Transit Commission
V2G	Vehicle-to-grid
ZEV	Zero emissions vehicle

1 Introduction

The complexity of distribution system load forecasting is increasing significantly in Ontario and globally due to factors such as decarbonization, decentralization, digitization, changing customer behaviours and evolving economic and policy conditions. Significant changes in demand, generation and flexibility on electricity distribution networks are driving changes in how these networks are managed and how capacity, investment and revenue planning is implemented. New demands emerging from the electrification of heat and transport, growing levels of distributed generation including variable renewable generation, and new sources of load flexibility (including energy storage) mean that local electricity distribution companies, such as Toronto Hydro, are facing increasing levels of uncertainty.

In this context, Toronto Hydro and Element Energy have developed the Future Energy Scenarios to facilitate a more detailed understanding of how these various drivers will change and interact over time. By utilizing long-term scenario-based load modelling, Toronto Hydro is able to frame the range of potential developments and understand the conditions in which each is expected to take place. The scenario-based approach to load modelling also enables Toronto Hydro to test various sensitivities around future levels of demand, generation and flexibility to increase the robustness of Toronto Hydro's planning strategies.

1.1 Toronto Hydro

Toronto Hydro-Electric System Limited ("Toronto Hydro") is the electricity distributor licenced by the Ontario Energy Board to serve the City of Toronto. Toronto Hydro has approximately 787,000 residential, commercial and industrial customers and distributes about 18% of the electricity consumed in Ontario.

Toronto Hydro recognizes that the energy sector is on the cusp of transformative change. In order to tackle climate change through decarbonization, electricity is expected to serve critical new roles, including fueling transportation and buildings. Toronto Hydro also recognizes that the pace and timing of these changes will be driven by a complex interplay of technological developments, consumer choice and policy. While there is certainty that fundamental change is ahead, there is uncertainty about how that change will unfold (e.g. the pace and adoption of EVs and heat pumps, the role of low emission gas and the scale of local vs. bulk electricity supply). This reality means that system load forecasting is becoming more complex for distributors like Toronto Hydro and must manage various interlinked growth drivers in an environment of high uncertainty.

To help manage these challenges, Toronto Hydro engaged Element Energy to develop the Future Energy Scenarios model. The Future Energy Scenarios offer a range of plausible trajectories on the path toward decarbonization.

Toronto Hydro supported the development of the Future Energy Scenarios model by providing data and information to Element Energy, as requested. Toronto Hydro did not develop the Future Energy Scenarios model or underlying methodology and relied on Element Energy's experience and expertise to guide the project.

1.2 Element Energy

Element Energy, an ERM Group company, is a leading low carbon energy consultancy with considerable experience in supporting electricity distribution business, particularly in relation to their future energy scenario planning, projections and load modelling. We bring together a talented and dedicated team to address the problem of climate change and the transition to low carbon energy. We ensure our analysis is fully evidence based and provide grounded advice on what is required to achieve the change to zero carbon energy systems. We focus on enabling technological, social and policy solutions to the problem of climate change and planning for the impacts these solutions have on our changing energy networks.

The success of Element Energy's demand, generation, consumption, and customer load modelling tools is based on our commitment to ensuring that our high-resolution scenario load modelling tools and outputs are robust, easy to use, accurate and customized to the specific needs of each distribution business. With the changing requirements on electricity distribution networks and the impact of factors such as embedded generation, energy storage, changing customer behaviour, new technology adoption, gas substitution, tariff reform and load control, we believe it is important to provide increased visibility of the impact of these factors under various future scenarios. This has necessitated the development of a robust, consumer choice-based load modelling approach that has the capability to produce reliable projections at a level of asset and customer resolution that has not previously been available to distribution businesses. We have implemented this approach for various distribution companies and other key stakeholders in the sector over the past 15 years and we bring the value of this experience and the existing tools and datasets we have developed to our work for Toronto Hydro.

Importantly, our extensive previous work in this area means that we have a modern, state-of-the art tool, the Future Energy Scenarios (FES) Model. This tool is in active use across various electricity distribution companies and, as such, is fully equipped with the latest innovations in this area, with a strong track-record of active use within the industry under the scrutiny and approval of the relevant regulators and associated reporting. The FES Model is also widely used by the various electricity distribution companies we work with to assess projections from their respective market operators and other key stakeholders in the sector.

1.3 Report Structure

This report provides an overview of the Future Energy Scenarios (FES) developed for Toronto Hydro. The report is structured to first outline the scenario framework and explain how individual scenarios are brought together to create four different possible future scenario worlds. Next, the report details how future scenarios were developed for each of the drivers of demand and generation considered in the FES. These drivers include, for example, the uptake of electric vehicles, energy efficiency measures and solar photovoltaic (PV) installations, etc. Finally, the report presents the key conclusions drawn from this work. The report is structured as follows:

Section 2 outlines narratives for four different future worlds and details how the different future scenarios for each of the key drivers are combined to produce these scenario worlds.

Section 3 explains the modelling framework, the application of bottom-up consumer choice approaches to developing uptake trends, and the customization process to capture local factors in Toronto.

Section 4 describes how the different individual uptake scenarios were developed for the key drivers of demand and generation, including the modelling methodology and the geospatial disaggregation across Toronto Hydro's operating region.

Section 5 presents the network impacts of the different scenario worlds, explaining why the trajectories follow different paths, and what this means in terms of real energy system developments.

Section 6 presents the conclusions drawn from this work.

2 Scenario Framework

The scenario framework is the method used by Element Energy to represent the range of uncertainties in the low carbon energy transition. This approach involves defining four **scenario worlds** that represent different energy system pathways, three of which reach net zero emissions by 2050. These pathways represent different positions on two main axes: speed of decarbonization and level of societal change (Figure 6Figure 6). Each of the four scenario worlds was constructed by combining uptake trends for all the individual drivers of demand and generation in Toronto, such as electric vehicles, heating, solar PV and core demand. To capture a broad range of different possible futures, three to four scenarios were produced for each driver and subsequently mapped to the scenario worlds (Table 1Table 1).

The scenarios worlds used in this work were developed through an assessment of existing sources that focus on the future of the low carbon transition in Canada[1], Ontario[2], and Toronto[3], as well as through engagement with Toronto Hydro's internal and external stakeholders. The most significant of the existing sources was TransformTO, the climate action strategy developed by the Toronto City Council, which similarly defines four scenarios of varying levels of ambition, including targets to be achieved in key sectors such as buildings, transportation, and generation. In contrast to the consumer choice-based modelling employed in the Future Energy Scenarios, the development of the TransformTO scenarios placed a more explicit focus on greenhouse gas reduction, looking at the overall requirements necessary to meet local decarbonization targets. Another key source was the framework used by the National Grid in the UK, which defines scenario worlds according to their level of societal change and speed of decarbonization. This framework served as a starting point for establishing, and visualizing, the difference between the scenario worlds, considering their positions on these two axes (Figure 6Figure 6).

A consumer choice-based approach was taken to modelling that aims to understand the types of customers across the network and thereby reflect the regional differences that may arise as part of the transition to a low-carbon society. The TransformTO scenarios were used as a reference point to define the overall level of ambition modelled in the four scenario worlds. The *Business as Planned* scenario from Transform TO was used as a template for the lower ambition *Steady Progression* scenario world, which involves progressing with existing plans for decarbonization and sees some level of emissions reduction without reaching net zero by 2050. The *Net Zero 2050* scenario from Transform TO was used as a basis for the two central scenario worlds, *Consumer Transformation* and *System Transformation*, both of which reach net zero by 2050 but vary in levels of societal change and electrification. Finally, the TransformTO *Net Zero 2040* scenario was the foundation for developing the highest ambition scenario world, which sees significant levels of electrification, behaviour change and efficiency.

Using this approach, the scenario worlds were able to capture local considerations of the energy transition that are specific to Toronto, whilst leveraging a robust and proven framework for network planning and load modelling. The four scenario worlds are structured as follows:

1. **Steady Progression:** Some progress is made towards decarbonization; however, this is the only scenario world that does not meet net zero by 2050.
2. **System Transformation:** The 2050 net zero target is met through a top-down approach with lower societal change and retention of the gas grid for biogas and renewable natural gas (RNG).
3. **Consumer Transformation:** The 2050 net zero target is met by a high degree of societal change as well as deep electrification of transport and heat in the standard scenario world.
    - **"Low Efficiency" sensitivity** – the uptake of electrified heat and transport technologies is the same as in the main Consumer Transformation world, but in this sensitivity the uptake of efficiency measures (building fabric & appliance), flexible technologies such as battery storage, and distributed renewable generation is limited.
4. **Net Zero 2040:** This is the fastest of the scenario worlds to achieve net zero, with the most ambitious level of societal change, utilizing both biogas and electric low-carbon technologies.
    - **"Low Efficiency" sensitivity** – Similar to the Consumer Transformation sensitivity described above, in this sensitivity the uptake of demand technologies is the same as in the main Net

Zero 2040 world, but the uptake of efficiency, flexibility and distributed renewable generation is limited.

The low efficiency sensitivity cases described above for the Consumer Transformation and Net Zero 2040 scenarios couple high electrification with a limited uptake of technologies which are able to mitigate peak demand growth, and therefore provide insight on the highest loads which might be expected on Toronto Hydro's network to 2050. Figure 6 shows a description and comparison of the scenario worlds, positioned relative to each other along axes denoting the requisite societal changes and the rate of decarbonisation achieved.

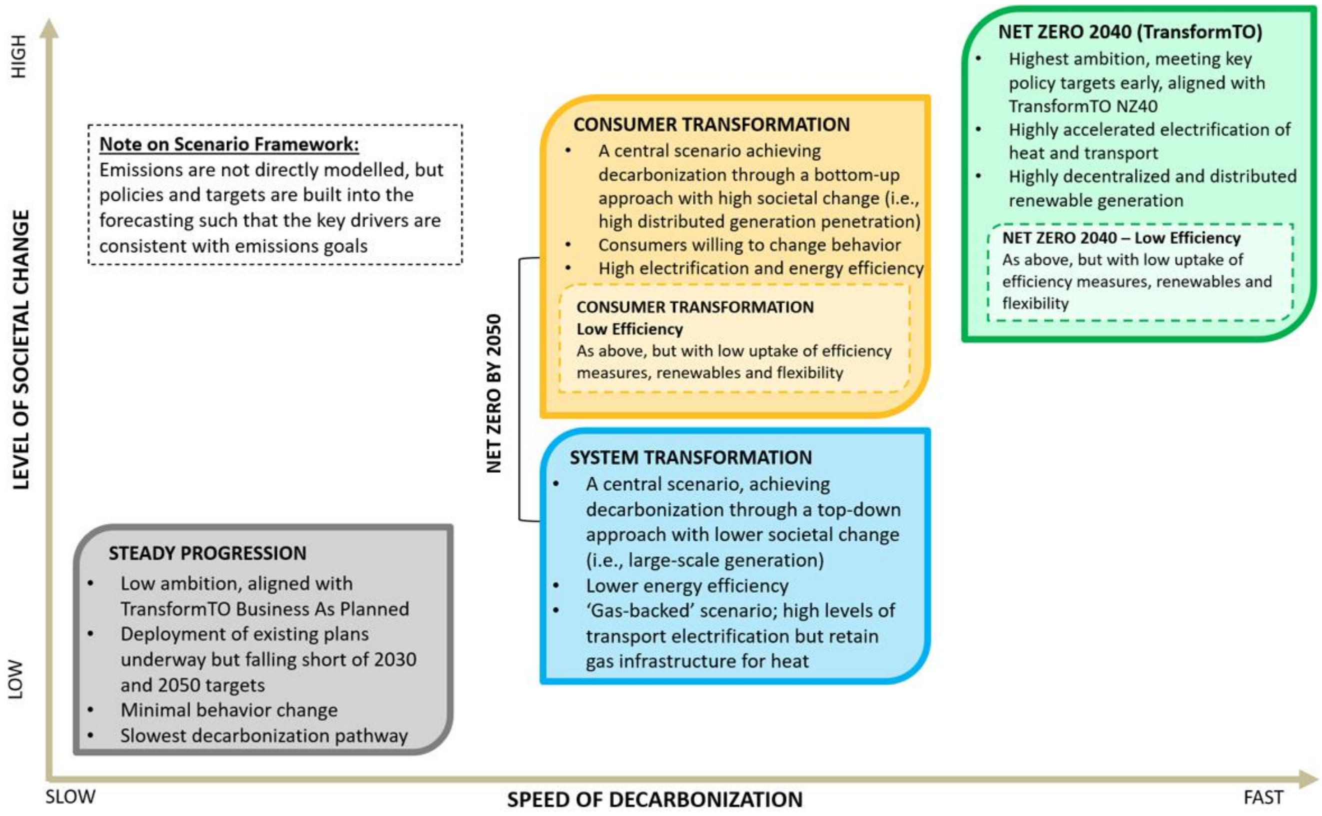


Figure 6: Scenario worlds defined on two axes: speed of decarbonization and level of societal change.

Table 1: Technology uptake scenarios that make up each of the four scenario worlds and the "Low" sensitivity cases applied to Consumer Transformation and Net Zero 2040.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Net zero by 2050?	No	Yes	Yes		Yes (by 2040)	
Core Demand						
Electrical efficiency	Low	Medium	High	Low	High	Low
Building stock growth	Single Projection					
Low-Carbon Transport						
Cars and light trucks	Low	Medium	Medium		High	
Medium/heavy trucks and Buses	Low	Medium	Medium		High	
Rail	Single Projection					
Smart charging / V2G	Low	Medium	High	Low	High	Low
Decarbonized Heating						
Heat pumps	Low	Medium plus hybrid HPs	High		Early High	
Thermal Efficiency	Low	Medium	High	Low	Very High	Low
Gas heating in 2050	High	Medium due to hybrid HPs	Zero		Zero	
Gas grid availability	Remains at current availability	Reduced utilization	Decommissioned by 2050		Decommissioned by 2040	
Gas grid composition	Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas	Shift to biogas, SNG, or other renewable natural gas	Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas until 2050		Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas until 2040	
Distributed Generation						
Solar PV	Low	Medium	High	Low	Very High	Low
Onshore wind	Low	Medium	High	Low	High	Low
Biogas	Low	Medium	High	Low	High	Low
Other non-renewable generation	High	Medium	Medium	High	Low	High
Battery Storage						
Domestic battery storage	Low	Medium	High	Low	Very High	Low
I&C behind-the-meter battery storage	Low	Medium	High	Low	High	Low

2.1 Scenario World Overview

SP

Steady Progression

The Steady Progression scenario world is aligned with the TransformTO *Business as Planned* (BAP) scenario, in which some progress is made towards net zero targets, but most sectors fall short of full decarbonization. This sees the deployment of existing plans but does not achieve 2030 and 2050 targets. The slow pace of change is largely a result of less ambitious energy policy and a lower level of consumer behaviour change.

By 2050, heating is still largely dominated by natural gas heaters, with a limited uptake of heat pumps and electric heating. There exists little policy to incentivize low carbon heating or to remove fossil fuel options from the market. In both domestic and I&C sectors, efficiency improvements are slow and capture only a basic level of home retrofit. The transport sector sees faster advancement in the low carbon transition, but still fails to fully decarbonize. The majority of cars and light trucks are electric by 2050, however uptake is inhibited by a lack of policy change and high battery prices.

Renewable generation sees a considerable increase from current levels, mostly driven by solar PV. However, wind and biogas generation see negligible uptake and renewable capacity still falls well below the levels required to replace non-renewable generation, which is not phased out.

ST

System Transformation

System Transformation is a central scenario world that achieves decarbonization through a top-down approach, reaching net zero by 2050. This assumes lower energy efficiency, lower societal change, more large-scale generation, and retention of gas infrastructure for low carbon heating (RNG and biogas).

Heating is decarbonized primarily through electrification; however, a considerable portion of heating systems switch to hybrid heat pumps, making use of retained gas infrastructure. Electricity grid demand from heating is consequently lower, however, this is offset by relatively poor energy efficiency improvements. Heating projections were designed to align with the projections developed by the Canadian Gas Association.

Transport follows a full electrification pathway, with all vehicle types converting to electric powertrains by 2050 or before. These changes are driven by falling technology costs, an internal combustion engine vehicle ban in 2035, and a more ambitious carbon tax policy.

Distributed renewable generation capacity sees a moderate increase; however, electrification is assumed to be primarily facilitated by increases in larger transmission-connected generation. Similarly, grid flexibility sees some advancements, with vehicle-to-grid slowly replacing standard smart charging.

CT

Consumer Transformation

Consumer Transformation is the second central scenario, achieving decarbonization primarily through bottom-up societal change rather than top-down system change. Shifts in consumer behaviour occur faster and earlier, with consumers increasingly prepared to engage with new smart technologies and flexibility markets. Widespread electrification is aided by high renewable generation penetration across the network, and steady improvements in energy efficiency.

Transport follows the same pathway as System Transformation, following a full electrification route that sees complete decarbonization by 2050. Similarly, the heating sector relies entirely on electrification, with ambitious policies introduced early on to incentivize heat pumps and ban fossil fuel systems. The gas grid is gradually decommissioned and, therefore, hybrid heat pumps are used only as a transition technology.

Since both heat and transport follow ambitious electrification pathways, electricity supply will need to scale up at a similar rate. Therefore, this scenario world sees a higher uptake in distributed renewable generation, driven primarily by falling technology costs. Non-renewables phase out completely by 2030, with this capacity replaced primarily by solar PV, wind, and biogas generation. Increases in generation are coupled with increases in efficiency, storage capacity and engagement in flexibility markets, facilitating a transition to a smarter energy system.

Consumer Transformation – Low Efficiency

The Low Efficiency sensitivity scenario is included to investigate the effects of coupling electrification on the scale of Consumer Transformation with low uptake of efficiency measures, flexibility and renewable generation. This will lead to higher peak loads and so provides useful insight for Toronto Hydro.

NZ2040

Net Zero 2040

Net Zero 2040 is the most ambitious scenario world and has been created to align with the TransformTO NZ2040 scenario. Key policy targets are met early, and electrification of heat and transport are accelerated such that full decarbonization is achieved by 2040. The approach taken is highly decentralized, with very high uptake in distributed generation and strong engagement from consumers. In order to develop these scenarios, it should be noted that underlying consumer choice models had to be manually tweaked to align with the required level of ambition.

Electric vehicle adoption follows a sharp uptake trajectory, driven by an evolving carbon tax policy, and an early ban on internal combustion engine vehicles in 2030. To reach full decarbonization by 2040, policy schemes to incentivize scrappage of older non-zero emissions vehicles are assumed in this scenario. Gas heating is banned in both existing and new homes by 2025, and financial incentives for low carbon heating continue until the mid-2030s, resulting in full electrification of heat by 2040.

Renewable generation scales to its highest potential within Toronto, helping to meet rapid increases in electricity demand across all sectors. Flexibility measures such as energy storage are also deployed at scale, helping to shift demand away from peak hours and reduce reinforcement requirements.

Net Zero 2040 – Low Efficiency

As described above for Consumer Transformation, a Net Zero 2040 Low Efficiency sensitivity scenario is included to investigate the effects of coupling the highest modelled electrification ambition with low uptakes of efficiency measures, flexibility and renewable generation. This will lead to the highest peak loads and so provides useful insight for Toronto Hydro.

3 Modelling Framework

3.1 Bottom-Up Consumer Choice Modelling

Element Energy has extensive experience with consumer choice modelling and has gathered a detailed understanding of which financial and non-financial parameters are relevant to describing consumer behaviour and modelled technology uptake. Element Energy has previously conducted detailed studies exploring the drivers for the uptake of various low carbon technologies, based on techniques such as willingness-to-pay analysis and consumer choice studies. The datasets from these studies have been used to determine the relative importance of the various technology attributes and uptake drivers.

Where consumer choice modelling is applied within the Future Energy Scenarios, the modelling for a given technology type generally follows the structure shown in Figure 7. This modelling approach is classified as discrete choice modelling[6]. Discrete choice models address a range of competing technologies, such as different vehicle types or heating technologies, and determine which technology is the most appealing to certain consumer types. Discrete choice modelling is based on the concept that consumers try to maximize their 'utility', which is a monetized indicator representing the value of a technology to a consumer. As technology attributes vary over time, they can be updated to follow market trends (changes in costs, subsidies, etc.). Changes in the economic evaluation of technology attributes allow for the modelling of market trends.

For example, in the case of different heating technologies, homeowners have to make a decision when replacing their old heating technology (e.g. a gas furnace) at the end of its life with a new technology (e.g. a heat pump, an electric heater or a new gas furnace). When making this decision, a customer would likely consider various factors including the upfront cost of the technologies, their running costs, the complexity of installation and the suitability of each technology for their property before reaching a decision. Discrete choice models convert the value of these factors to consumers is into an equivalent monetary value, or 'utility', so that they can be compared quantitatively.

[6] Kenneth E. Train, Cambridge University Press, 2002, "Discrete Choice Methods with Simulation".

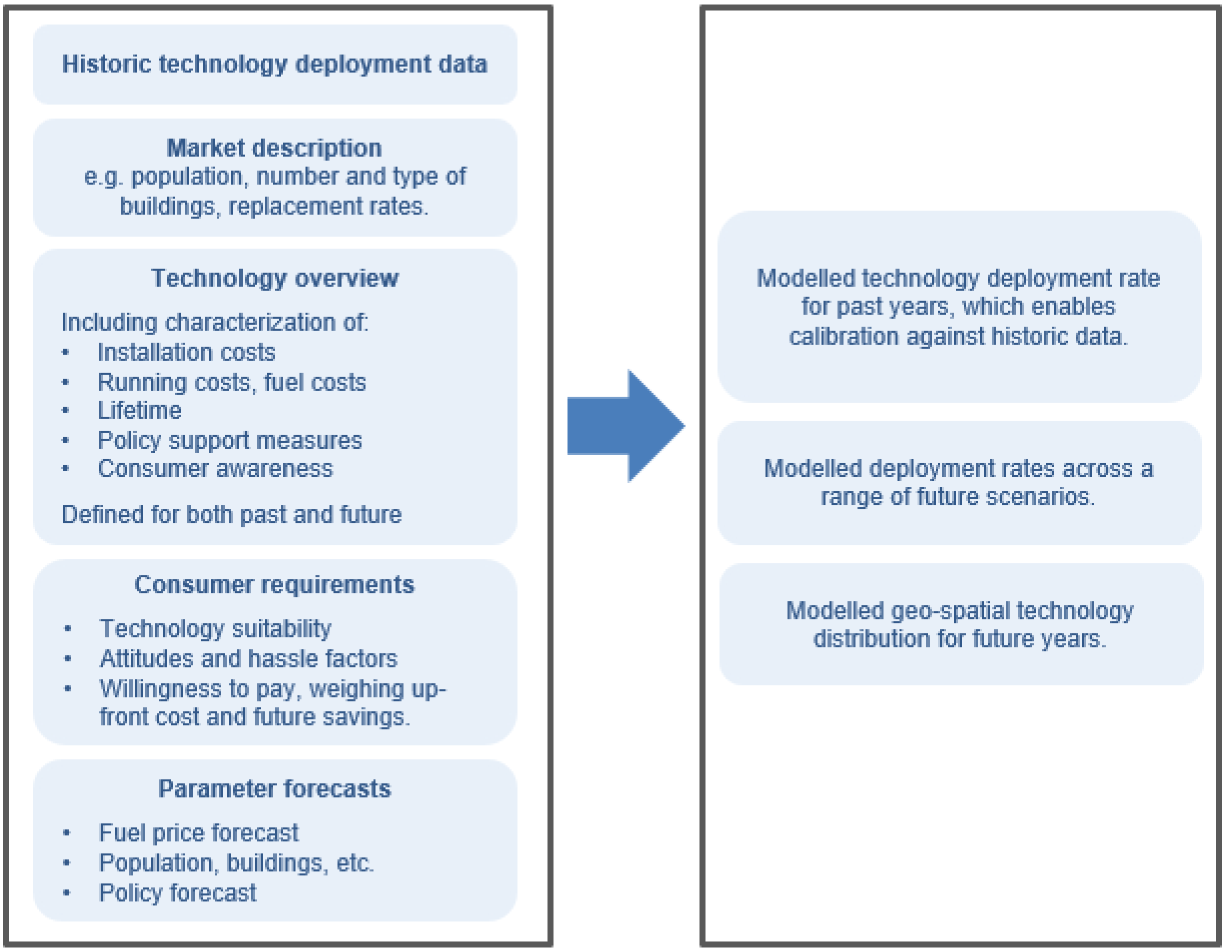


Figure 7: General approach to modelling future technology deployment.

This approach allows uptake trajectories to be based on real-world conditions (technology characteristics and costs) and actual purchasing decisions (including non-financial barriers such as charging infrastructure availability for electric vehicles or hassle barriers for heat pumps) rather than aspirational targets.

As shown in Figure 7, the first step is to gather and analyze all available datasets that describe historic deployment rates. This provides an understanding of the historic uptake levels at the most granular geospatial resolution possible. These datasets also support model calibration by enabling a correlation of how many units were deployed under historic market conditions. The subsequent modelling steps involve a variety of other parameters (such as market size, technology definition and consumer requirements), which are used to calculate a modelled purchase decision for each consumer type.

The consumer choice model evaluates the following for each year:

- The number of consumers making a purchase decision (by consumer type).
- Which technologies are purchased by consumer type, considering:
    - Financial parameters: capital cost, operational cost, taxes, fuel cost, revenues, policy incentives, etc.
    - Technology suitability and consumer awareness.
    - Hassle factors and attitudes around installation and adoption.

The modelling tools employ a tailored modelling logic to address the characteristics of the market and decision-making processes depending on the low carbon technology in question. In Section 4, the specific modelling methodologies for each technology included in this analysis are covered in more detail.

3.2 Local Factors and Customization to Toronto

Toronto Hydro's distribution area covers the city of Toronto. For planning purposes, the city is divided into 140 regions known as neighbourhoods[7], shown below in Figure 8. These neighbourhood were defined based on Statistics Canada census tracts and have a minimum population of at least 7,000 to 10,000.

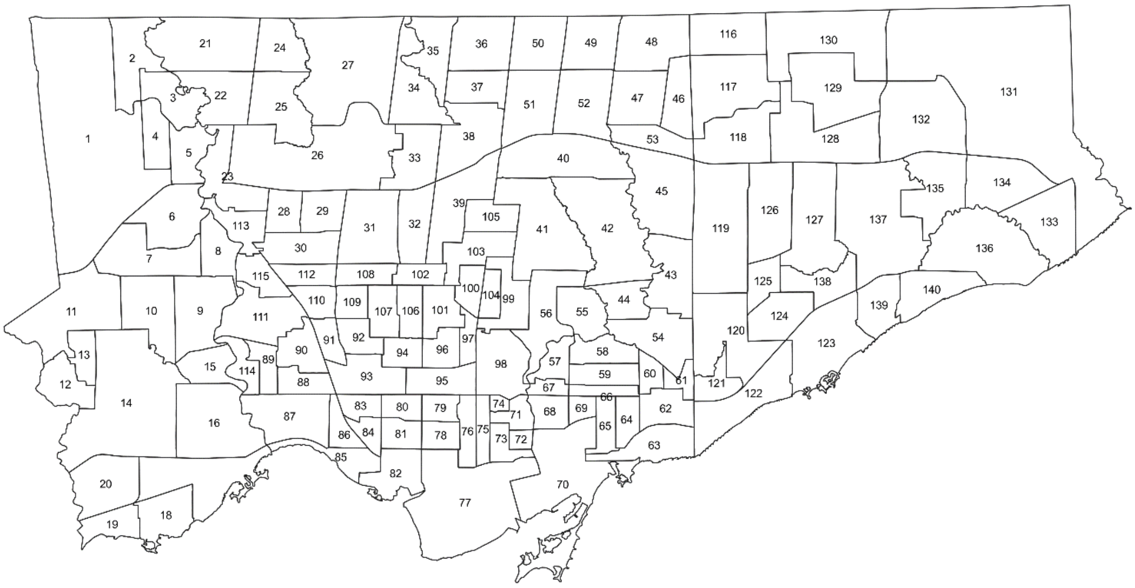


Figure 8: Toronto neighbourhoods.

Many of the drivers modelled in this work are resolved to neighbourhood level. In some cases, (e.g. electric vehicles), these are then further mapped to specific transformer station buses for the purposes of load modelling. For others, such as those based on building stock archetypes (e.g. core demand and heating technologies), modelling is performed using an archetype approach and relies on the asset-level connection counts from Toronto Hydro.

The consumer choice models utilized in this work have been adapted for Toronto Hydro to take into account specific local factors, such as policy measures (e.g. Canada Green Homes Grant) and the breakdown of vehicle stock as discussed in Section 4.3. Additionally, the modelling considers local geography when distributing demand and generation across the region, such as a detailed look at potential electric vehicle charging locations, discussed in Section 4.3.6, and an assessment of the most suitable locations for onshore wind turbines, discussed in Section 4.4.3.

[7] City of Toronto, About Toronto Neighbourhoods, 2022. *Note that since the time of analysis, some neighbourhoods have been split up because of very high population growth. Effective after April 12, 2022, the number of neighbourhoods in Toronto is 158.*

4 Development of Demand and Generation Driver Projections

Modern electricity networks supply energy to homes and businesses to service a broad range of applications. In this analysis, the electricity provided for most conventional applications is referred to as “core demand”.

At present, the majority of energy for both transport and space heating is derived from non-electrical energy vectors (such as gasoline and diesel for transport, or natural gas for space heating). As part of the decarbonization of transport and space heating, there is potential for a significant level of electrification to occur across these sectors making them particularly important areas of analysis for electricity network planning and load modelling. As such, transport and space heating are each modelled separately to “core demand” in this analysis to support a more detailed understanding of potential future demands from these technology segments.

Similarly, increasing levels of distributed electricity generation (e.g. from solar PV, wind, etc.) also play an important role in projecting future loading across electricity networks as net zero strategies are implemented. Hence this analysis also explores the impact of distributed generation from a variety of technology options (see Section 4.4) on future network loads under a range of scenario options.

As the energy provision of the distribution network grows due to factors such as the electrification of heat and transport as well as increasing distribution electricity generation, generally the peak instantaneous power demand experienced by the network will also increase. To help reduce the amount of network reinforcement required to accommodate increases in peak demands across the electricity network, several flexibility options exist which help to move demand at peak times to different times of the day. This analysis captures the impact of flexibility options such as energy storage, smart charging and vehicle-to-grid options for electric vehicles, as well as time-of-use tariffs. Energy storage is modelled as a distinct technology segment which can help to shift power loads by charging at times of low grid utilization and discharging during peak hours. Similarly, smart charging and vehicle-to-grid options can help to shift loads from EVs by managing when car batteries charge and allowing them to act as electrical storage units. This is captured as a sensitivity within the modelling of transport demand by assuming different charging behaviours for electric vehicles in Toronto.

The report sections below provide further details on the assumptions, scenarios and modelling methodology used in the analysis of core demand, heating, transport, generation and flexibility, and how these are used to establish the scenario framework used for projecting loads across the Toronto Hydro network out to 2050.

4.1 Core Demand

The majority of current electricity demand within the Toronto Hydro network can be categorized as underlying demand from either domestic customers or industrial and commercial (I&C) customers. Underlying demand here refers to all electricity usage relating to existing appliances, including electrical heating or cooling, but excluding demand from new low carbon technologies such as electric vehicle charging or heat pumps. Collectively this underlying demand from domestic and I&C customers is referred to as the “core demand” on the network. Future core demand for domestic and I&C customers is primarily dictated by two key variables:

- The total number of customers connected to the network, which is assumed to be controlled by the size of the building stock; and
- The energy intensity of the customers within those properties, which is assumed to be controlled by the uptake and efficiency of customer appliances.

This concept is illustrated in Figure 9. The following section details the modelling used to characterize Toronto’s current and future core demand.

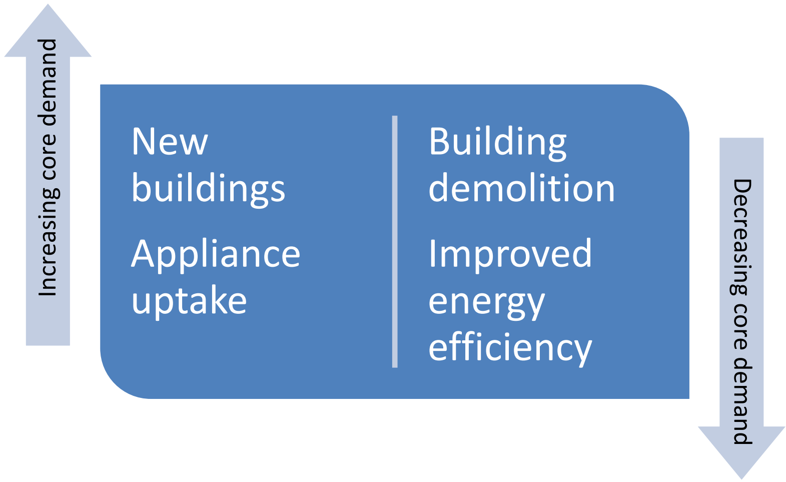


Figure 9: Illustration of core demand drivers and their effects.

The mapping of the different core demand parameters to the scenario worlds is given below in Table 2

Table 2: Domestic and I&C efficiency scenario mapping.

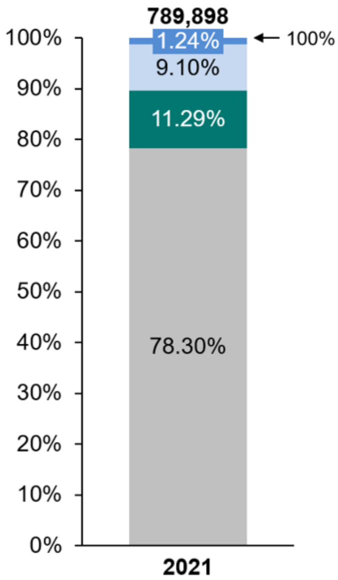
Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Domestic Electrical Efficiency	Low	Medium	High	Low	High	Low
I&C Electrical Efficiency	Low	Medium	High	Low	High	Low
Appliance growth	Single Projection					
Domestic Building Stock Growth	Single Projection					
I&C Building Stock Growth	Single Projection					

4.1.1 Archetype Definitions

Understanding the energy usage of different building types across the modelled region is essential for accurately characterizing the core demand. Customers on the Toronto Hydro network are classified into 11 “rate classes” based on different use cases and sizes, six of which are of particular interest from the perspective of modelling domestic and industrial core demand. Table 3 summarizes the rate classes, and Figure 10 shows the breakdown of Toronto Hydro’s connections in the relevant rate classes (as denoted in Table 3). The majority of connections are residential.

Table 3: Toronto Hydro customer rate class definitions

Customer Type	Toronto Hydro Rate Class
Domestic	Residential
	Competitive Sector Multi-Unit Residential (CSMUR)
Industrial and Commercial (I&C)	General Service (GS) < 50kW
	GS 50 – 999kW
	GS 1 – 5 MW
	GS >5 MW (Large Users)
Other (not in scope of FES analysis)	*Street Lighting*
	Unmetered Scattered Load
	Standby Power
	microFit
	Retail Services



Rate Class	Connections	%
Customers over 5MW	54	0.01%
Customers between 1MW-5MW	494	0.06%
Customers between 50-999KW	9,768	1.24%
Customers under 50KW	71,887	9.10%
Multi-Unit Residential	89,209	11.29%
Residential	618,486	78.30%

Figure 10: Breakdown of relevant rate classes across the Toronto Hydro network.

Much of the analysis relating to core demand and low carbon technology uptake is contingent upon the use of building archetypes, also called classes, which build upon the connection data (split by the rate classes shown in Table 3) provided by Toronto Hydro. Archetypes allow the energy usage characteristics of a wide array of users to be considered in the analysis, providing high levels of regional variation while also supporting analytical efficiency. The building stock within Toronto Hydro’s region has been split into 32 domestic and 40 non-domestic archetypes, each defined by a set of relevant characteristics. The process and resulting distribution are explained in more detail below.

Domestic Archetypes

The 2016 Census of Population[8] provides household statistics at neighbourhood resolution. This dataset was used to segment the domestic building stock into groups of four different structural types (single detached houses, double or row houses, low-rise apartments, and high-rise apartments) and four age categories (pre-1960, 1960-1980, 1980-2010, post-2010). The Census data contains records of more domestic properties than there are connections within Toronto Hydro's residential and multi-unit residential rate class data. This is because there are some residential properties, such as apartment blocks, which in some cases connect to the network as bulk-metered General Service connections within Toronto Hydro's rate classes. The bulk-metered residential properties are allocated to I&C archetypes in this analysis, while the number of buildings within the domestic archetypes matches the total number of residential and multi-unit residential rate class connections.

Figure 11 shows the distribution of residential and multi-unit residential rate class connections (i.e. domestic connections) across the Toronto neighbourhoods, per Toronto Hydro's rate class data[9].

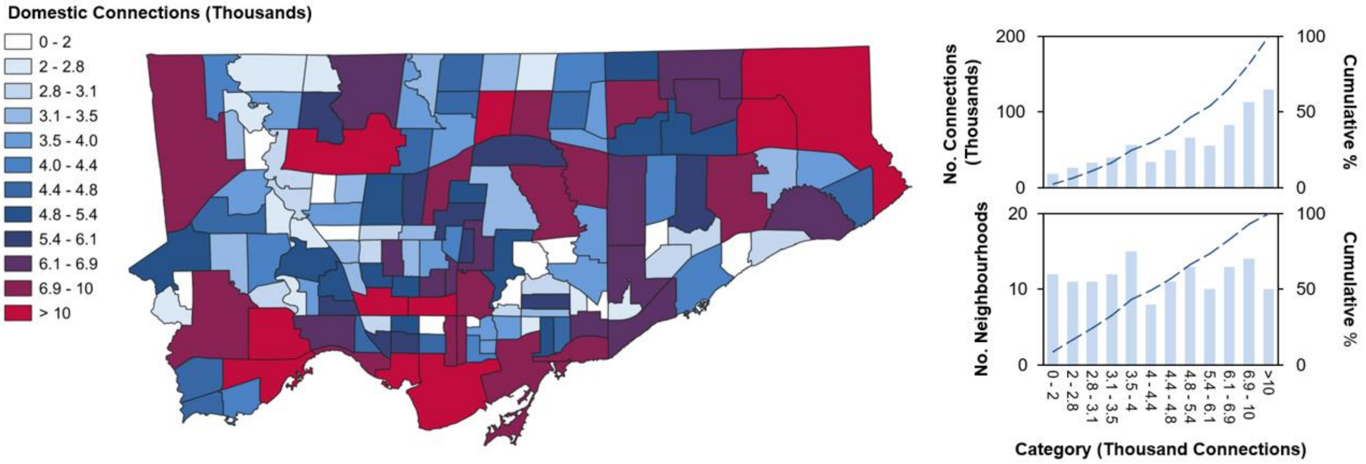


Figure 11: Distribution of domestic connections across Toronto neighbourhoods[9].

The distribution of dwelling types across neighbourhoods varies considerably, with more densely populated regions of the city having a higher proportion of apartment style homes utilizing multi-unit residential connections. This distribution of dwelling types (see Figure 12) has a significant impact on the uptake of various demand technologies seen in the scenarios.

[8] Statistics Canada, The Census of Population – Neighbourhood Profiles, 2016
[9] Toronto Hydro, Rate Class connection statistics, 2022

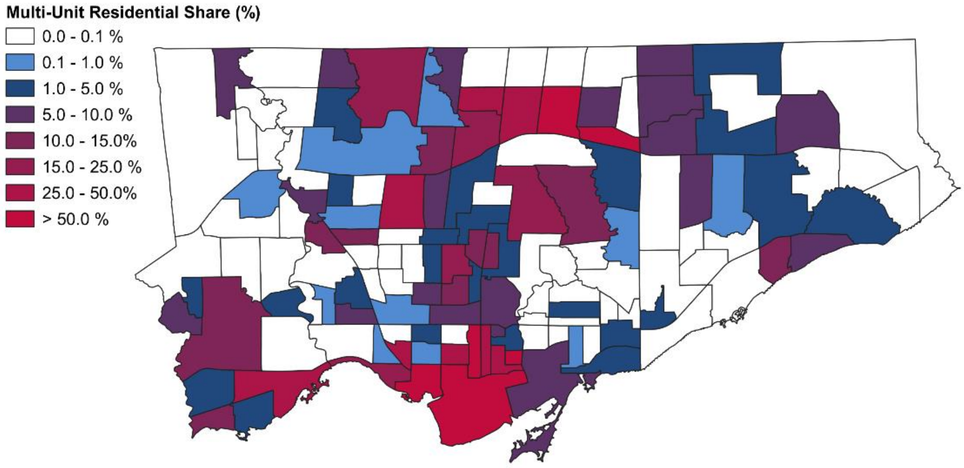


Figure 12: Share of multi-unit residential connections within Toronto Hydro's domestic rate classes.

The Toronto Hydro rate class data does not contain any additional information on the types of buildings present within the stock. Using neighbourhood and ward-level census data[8], as well as data from TransformTO[3] and The Survey of Household Energy Use[10], the connection counts were subdivided according to several parameters as follows (it is assumed that the distribution of building descriptors among the census households is retained in the Toronto Hydro rate class dataset for the purposes of subsequent calculations).

The parameters used to subdivide the stock into archetypes are heating fuel type (gas, electric, other), building age and the structural types listed above. These parameters were selected for the segmentation as buildings of similar structural type and age have similar energy usage characteristics. These factors also provide a reasonable indicator for which low-carbon heat source a building may be suited.

Archetypes are not expected to have the same share of heating fuel types – for example the proportion of homes currently using electric heating is higher within apartments than detached houses. Data from the Survey of Household Energy Use was used to determine the prevalence of existing heating fuels within each housing type.

It was found that the majority (>90%) of the building stock in Toronto currently uses natural gas as a heating fuel. Gas fuelled archetypes were subdivided into the four structural categories given above, while archetypes fueled by other means required less granularity (owing to their small share of the overall stock) and were hence categorized as houses or apartments. The breakdown of the archetypes' characteristics is illustrated in Figure 13. This leads to 32 domestic archetypes in total, consisting of 16 gas heating archetypes, 8 electric heating ones and 8 other heating archetypes as follows:

- **Gas heating**: 1 [Fuel Type] x 4 [Building types] x 4 [Age Categories] = 16 archetypes
- **Electric heating:** 1 [Fuel Type] x 2 [Building types] x 4 [Age Categories] = 8 archetypes
- **Other heating:** 1 [Fuel Type] x 2 [Building types] x 4 [Age Categories] = 8 archetypes

[10] Natural Resources Canada, Survey of Household Energy Use Data Tables, 2015

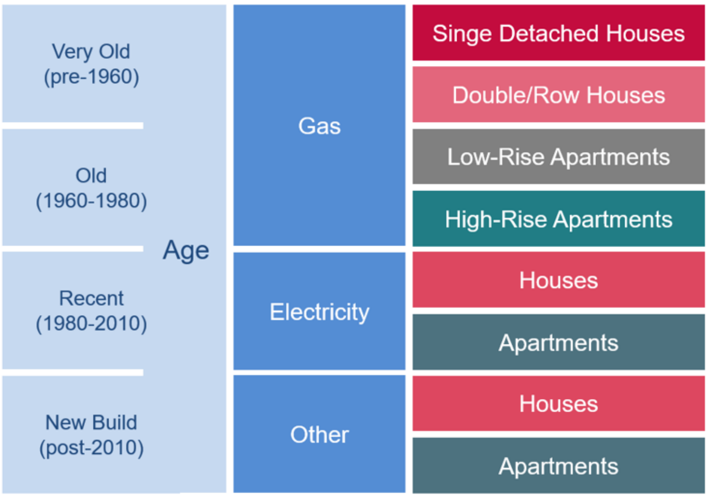


Figure 13: Breakdown of defining characteristics for domestic archetypes.

The distribution of archetypes within the Toronto Hydro rate classes is shown below in Figure 14[11].

The homogeneity of domestic multi-unit residential connections as high-rise apartment blocks is shown in Figure 14a, explaining the prevalence of this rate class in the City's urban centres in Figure 12. There is a relatively even split of building ages in Figure 14b, and the high proportion of gas heating discussed above can be seen clearly in Figure 14c.

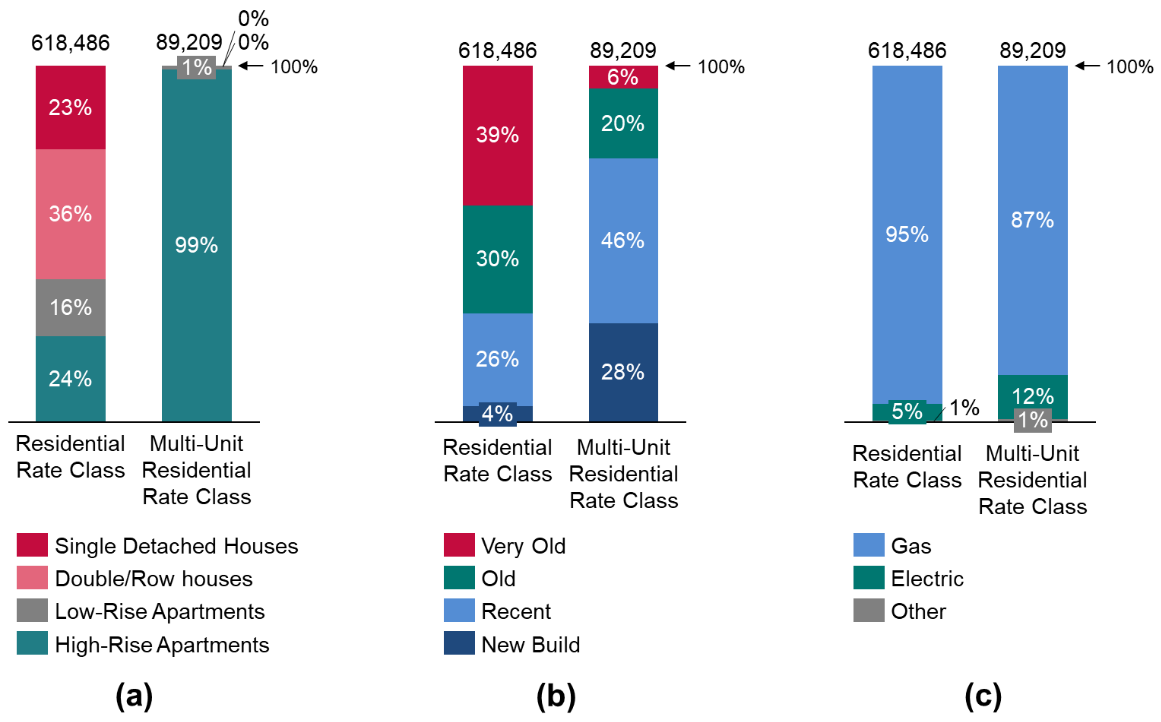


Figure 14: Distribution of Toronto Hydro's domestic building stock by (a) structural type; (b) age; and (c) current heating fuel (2021).

[11] There are a number of domestic properties which, owing to their metering arrangements and the handling of rate classes within the modelling, are categorized within I&C Multi-Unit Residential archetypes, and these are not accounted for in Figure 14.

Industrial and Commercial Archetypes

Figure 15 shows the distribution of employees across the city, in line with City of Toronto employment figures for 2020. The data shows that the majority of neighbourhoods contain relatively few employees, while most employees work in a few specific neighbourhoods. 70% of the neighbourhoods are home to fewer than 10,000 employees each, while 30% of the city's workforce is contained within just six (of 140) neighbourhoods (see inset graphs in Figure 15). There are two main centres of employment in the city: one in the city centre (bottom centre of the map) and one in Etobicoke North (top left of the map).

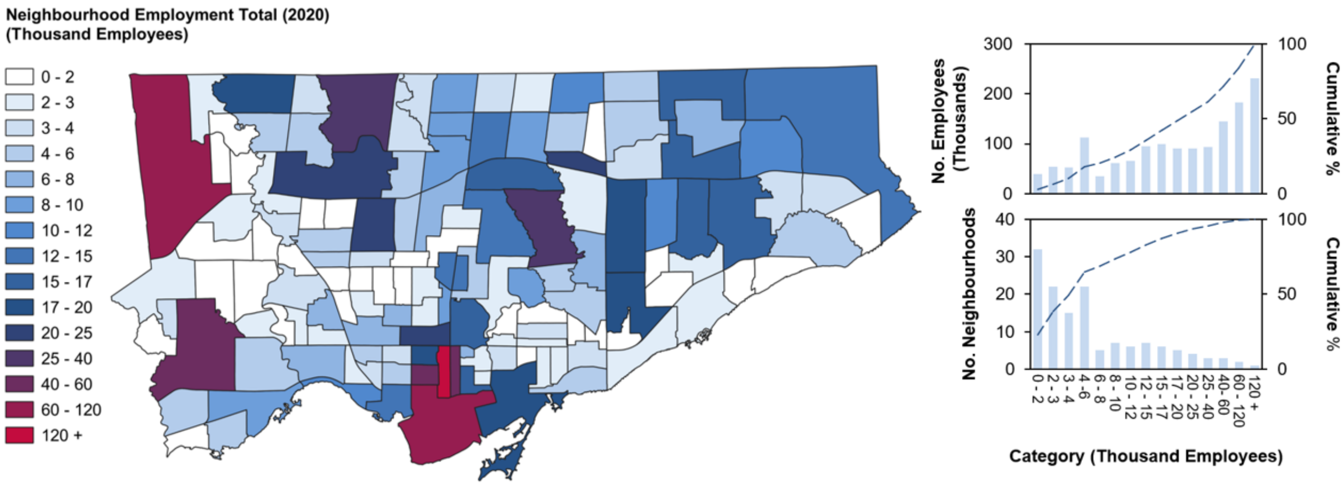


Figure 15: 2020 Distribution of Employees in Toronto[12].

The data also showed the number of establishments (i.e. workplaces) per neighbourhood per NAICS[13] sector which, when combined with the employee counts in Figure 15, can give an indication of the size of I&C buildings in different regions of the city. This dataset is shown below in Figure 16, presented as employees per establishment.

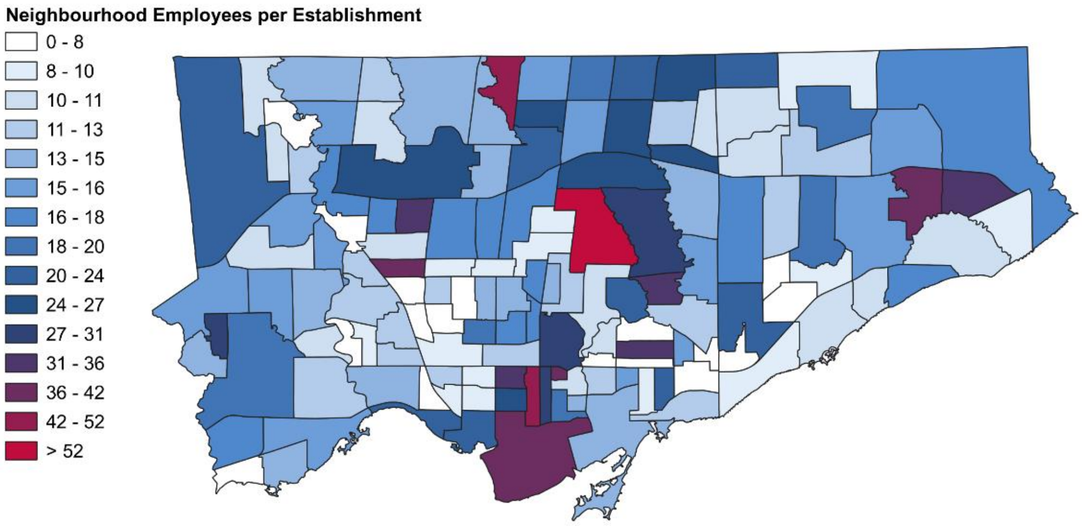


Figure 16: Employees per Establishment, 2020[12].

The dataset shown in Figure 15 is important because the derivation of the I&C building stock growth trend, as described in Section 4.1.2, is based upon employment projections. The growth in employment is assumed to

[12] City of Toronto, Toronto Employment Survey, 2020

[13] North American Industrial Classification System [NAICS & SIC Identification Tools | NAICS Association]

be in proportion to the growth in buildings in each neighbourhood, and therefore the employee density shown in Figure 16 is also implicitly retained in that analysis.

The sectoral split of employees and establishments in Toronto referenced above is shown below in Figure 17. Note that the full list of 21 NAICS sectors was condensed into seven simplified sectors for the purposes of this analysis.

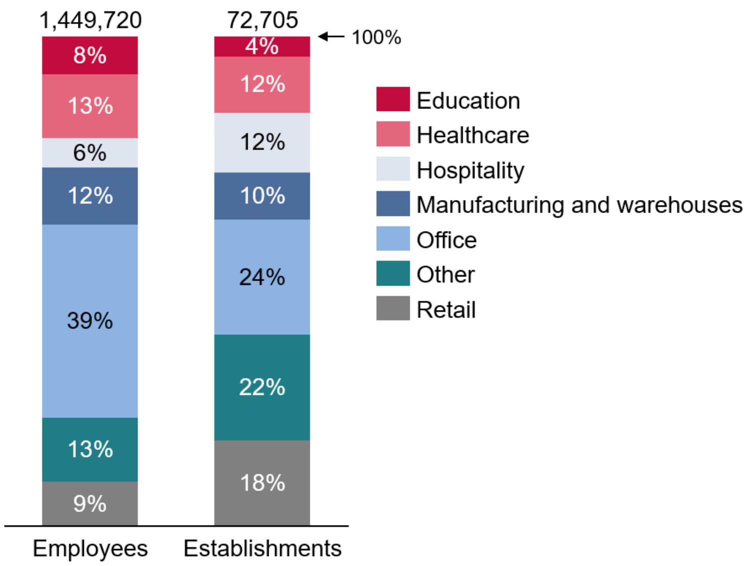


Figure 17: Simplified sectoral split of employees and establishments in 2020[12].

The seven simplified NAICS sectors described above formed the basis of the archetypes developed for this analysis. In addition to these seven, some multi-unit residential buildings are categorized as I&C connections in this analysis because they connect to the network via bulk-metered General Service connections, rather than individually metered multi-unit residential connections (see Table 3). Other characteristics considered were the fuel type (split into gas, electricity and other), and age (split by existing and new build). Note that it has been assumed for simplicity that all new builds in all scenarios will be fuelled either by gas or electricity. The breakdown of the archetypes' characteristics is illustrated in Figure 18. This leads to 24 existing and 16 new build archetypes as follows:

- **Existing:** 1 [Age Category] x 3 [Fuel Types] x 8 [Sectors] = 24 archetypes
- **New Build:** 1 [Age Category] x 2 [Fuel Types] x 8 [Sectors] = 16 archetypes

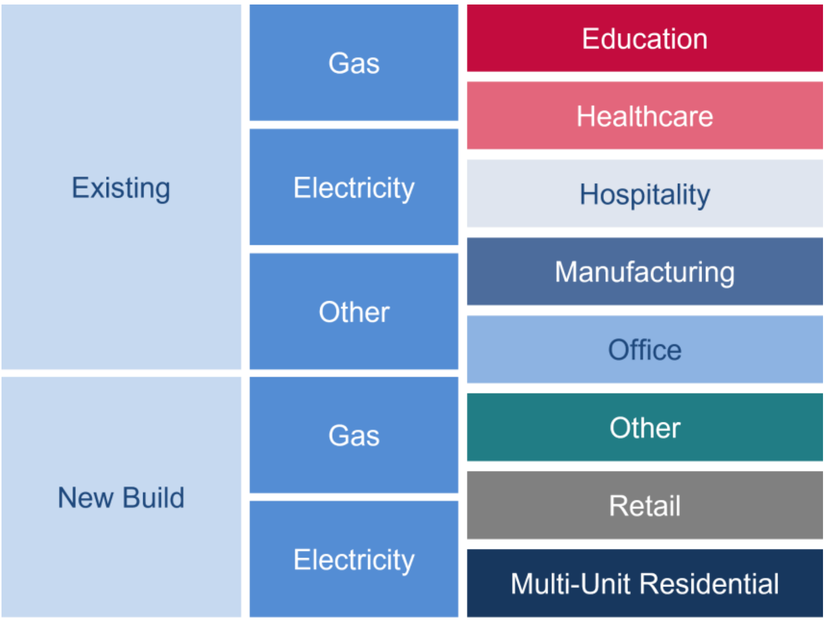


Figure 18: Breakdown of defining characteristics for the I&C archetypes.

Note that the archetypes are not characterized by rate class – customer counts for each non-domestic archetype were produced for all four I&C rate classes (see Table 3). To achieve this, a mapping between rate classes and NAICS sectors was produced (i.e. defining which NAICS sectors would be expected to contain which rate classes). The number of NAICS establishments present within the data differed slightly in each neighbourhood to the number of connections reported by Toronto Hydro. As such, the proportions of each sector were retained from the NAICS data but the overall total number of connections within each rate class was assigned according to the data provided by Toronto Hydro.

The resulting distribution of archetypes then formed the starting point for the analysis of I&C core demand and building stock growth in Toronto.

4.1.2 Building Stock

The number of buildings connected to the distribution network has been modelled as the net result of two competing factors – demolition of the existing stock and the rate of new build completions in each sector. As with the building archetyping, the building stock trends are split into domestic housing and I&C establishments.

Domestic Building Stock

Neighbourhood level net domestic growth projections (to 2041), based on the City of Toronto 2013 provincial growth plan were used for this analysis. The scenario referred to as the 2012 neighbourhood growth plan ("GP2012 NH"), has been used to model domestic stock growth. The data was extrapolated from 2041 to 2050 and mapped to the domestic housing archetypes discussed in Section 4.1.1.

Archetype specific (i.e. house and apartment) growth rates consistent with those contained in GP2012 NH were then applied to Toronto Hydro's domestic connection counts, using the distribution of dwelling types from the domestic archetypes. As such, the overall modelled growth differs slightly from the GP2012 NH trend, because the distribution of homes (and consequently the growth of the stock) in that dataset differs from that in the modelling presented in this report.

A 2008 study by Watson and Associates[14] on behalf of the City of Toronto contains historical data and projections around the ratio of demolitions to new builds across different housing types. The demolition rate derived from the report is applied to the net growth seen in each neighbourhood to find the total number of demolitions across the city (and implicitly the gross number of new builds). Figure 19 summarizes how the data described above were combined to produce a stock growth projection.

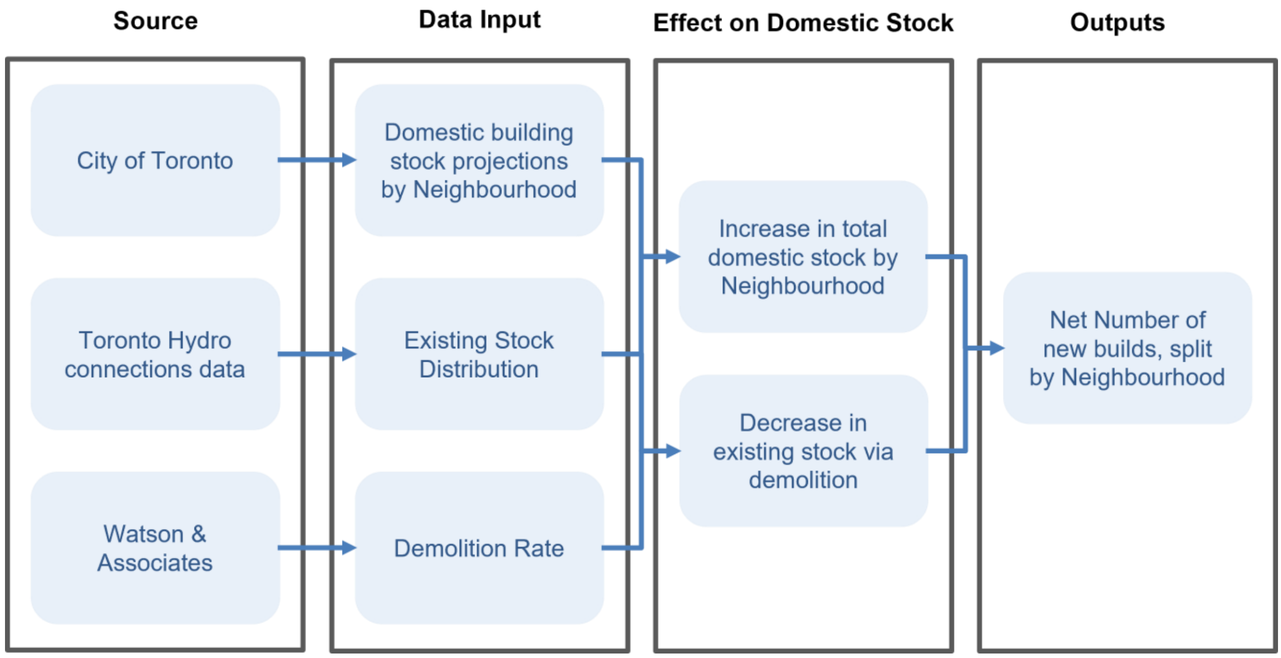


Figure 19: Method for developing domestic building stock growth projection.

Figure 20 shows the modelled net housing stock growth derived from the data sources described above. Growth (consistent with GP 2012NH) is applied to new builds only, while demolition is applied to existing stock only. The majority of growth is concentrated in apartments, which is also consistent with the neighbourhood growth plan.

[14] Watson & Associates, City of Toronto Development Charge Background Study, 2008

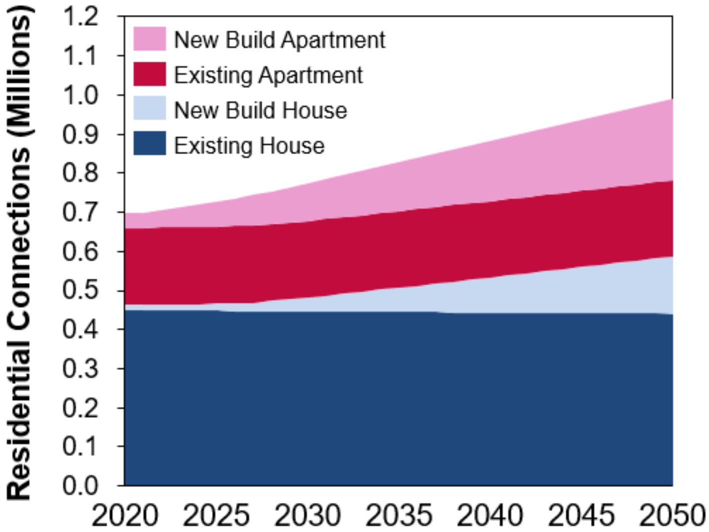


Figure 20: Modelled residential stock growth, split by dwelling type and age, rebased to Toronto Hydro connection counts in 2021.

Figure 21 shows a comparison of the overall modelled growth rate relative to that of the GP2012 NH data, TransformTO and the Canadian Ministry of Finance's population projection, showing a general alignment between the modelled approach and that of the data available in literature.

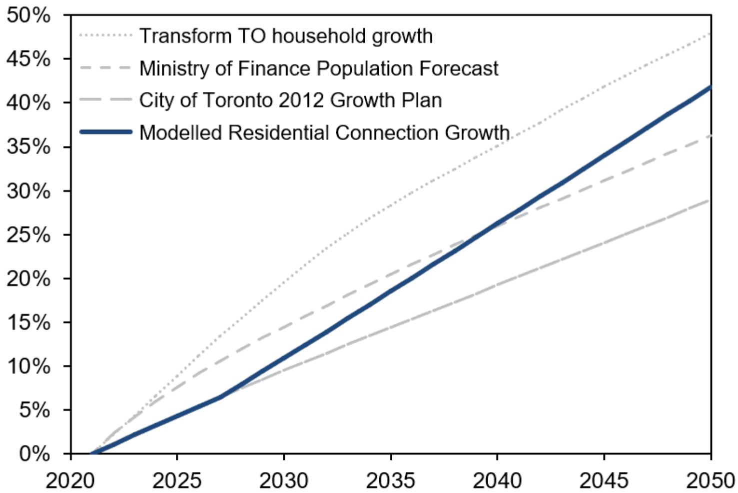


Figure 21: Comparison of modelled growth with different Toronto housing and population projections.

Figure 22 shows the modelled distribution of domestic buildings across the city in the base year and 2050. The differing building stock growth rates in action across different neighbourhoods can be seen by comparing the 2021 and 2050 distributions.

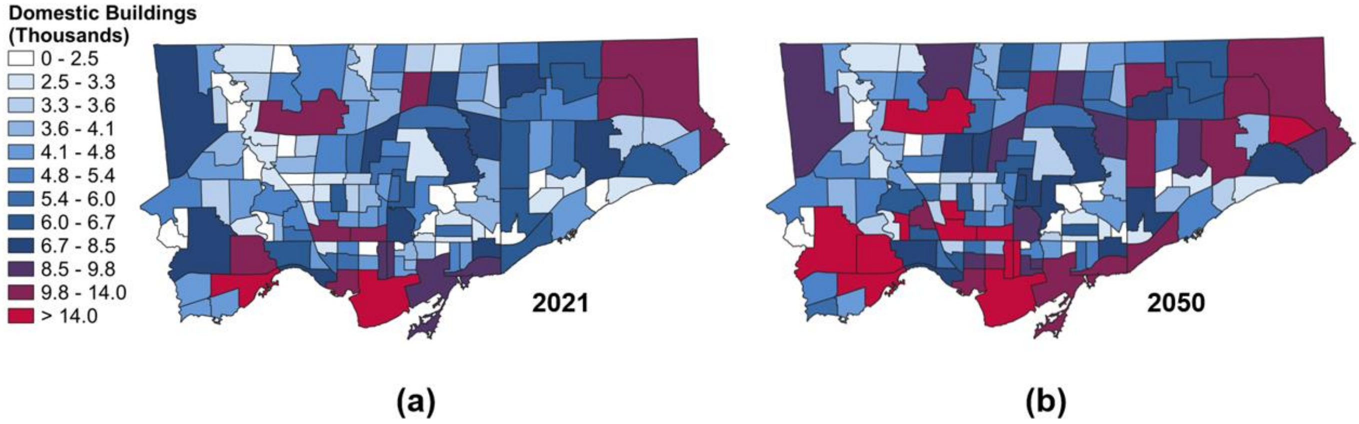


Figure 22: Maps of domestic building stock in (a) 2021 and (b) 2050.

Industrial and Commercial Building Stock

The analysis for I&C building stock was also based upon multiple data sources. The high-level process is displayed below in Figure 23.

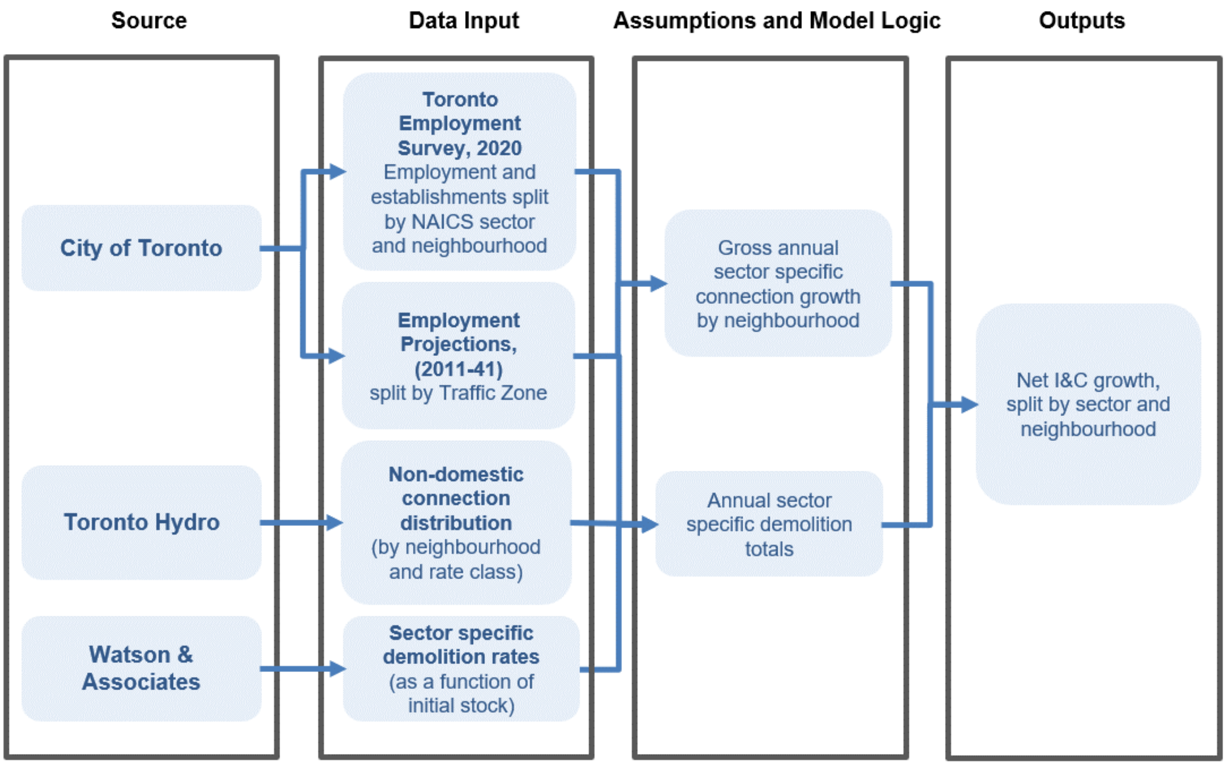


Figure 23: Method for developing the industrial and commercial building stock growth projection.

Alongside the employment statistics discussed in Section 4.1.1, City of Toronto industry employment projections from 2011 to 2041, split by Traffic Zones, were used in the I&C building stock growth analysis[15]. These projections contained five scenarios, combining different rates of economic growth and the projected impacts of the SmartTrack rail system[16]. These are summarized in Table 4 and Figure 24. Scenario 1 (medium growth, no SmartTrack) has been used as the basis for the FES analysis.

Table 4: Synopsis of City of Toronto employment projection scenarios.

Scenario	Growth	SmartTrack
Scenario 1	**Medium**	**False**
Scenario 2	Medium	True
Scenario 3	Low	False
Scenario 4	Low	True
Scenario 5	High	True

[15] Toronto Data Management Group, Traffic Zones Boundary Files, 2006 (Toronto Hydro's network area covers 677 traffic zones).
[16] City of Toronto, SmartTrack Stations Program, 2021

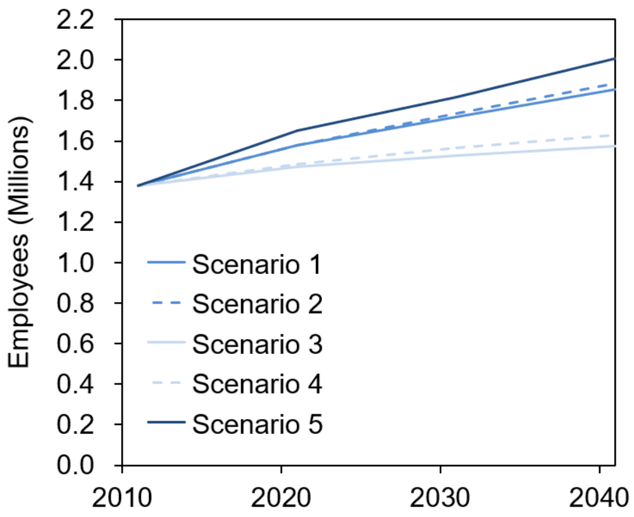


Figure 24: City of Toronto employment projection scenarios, 2011-2041.

The growth rate given by the medium growth employment projection described above has been used as a proxy for net I&C stock growth. The neighbourhood level NAICS sector split from the 2020 Employment Projection conducted by the City of Toronto was used to disaggregate the growth into neighbourhood regions. This was then rebased, using the neighbourhood distribution of the I&C archetypes discussed in Section 4.1.1.

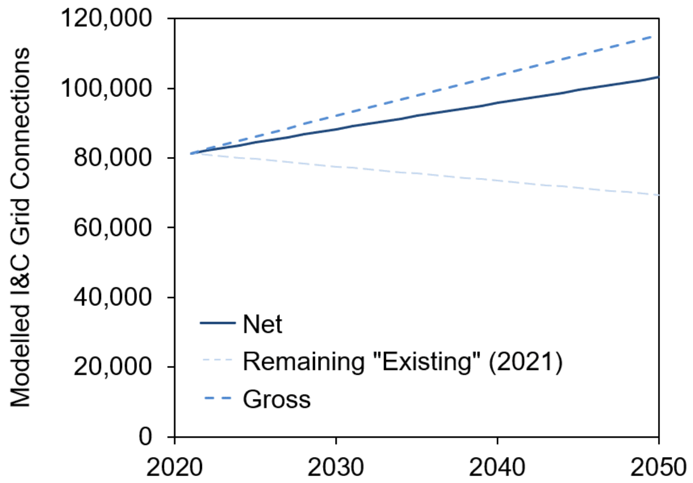


Figure 25: Modelled total I&C building stock projection.

Figure 26 shows the distribution of I&C buildings across Toronto in the base year and 2050. Unlike the domestic stock growth (shown in Figure 22), I&C building stock remains distributed around the city in a manner similar to the present day, with most growth occurring in regions which already have a high concentration of commercial buildings. High voltage I&C connections (defined as those in rate classes Customers between 1MW-5MW and Customers over 5MW) are excluded from this analysis. The growth in demand from these customers is modelled based on Toronto Hydro's assessment of the connections expected to come online in the near future.

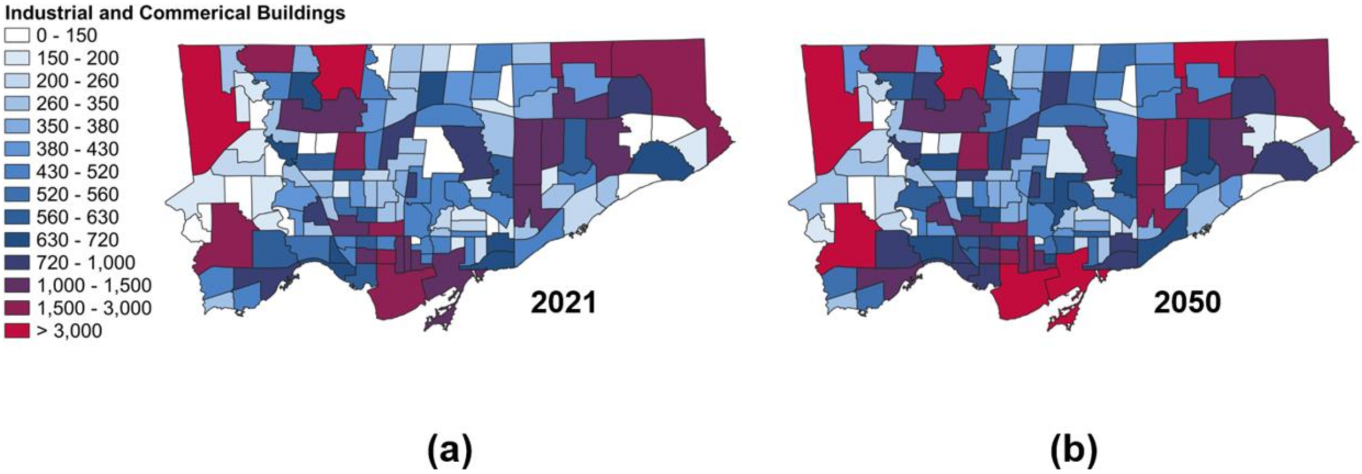


Figure 26: Maps of modelled I&C building distribution in (a) 2021 and (b) 2050.

4.1.3 Core Electrical Efficiency

Domestic Appliance (Non-Heat) Efficiency Projection

The domestic electrical efficiency projections were developed using appliance turnover as the mechanism for energy use reduction. Within the modelling, consumers are assumed to upgrade to a new appliance at the end of an average appliance lifetime, either to:

- an appliance with an average improvement in energy consumption, which was based on the Canada-wide energy use dataset containing annual energy consumption by appliance type; or,
- the most efficient available appliance, the energy consumption of which was taken from the Energy Star website.

Figure 27 shows the high-level methodology used to generate the domestic appliance efficiency projections.

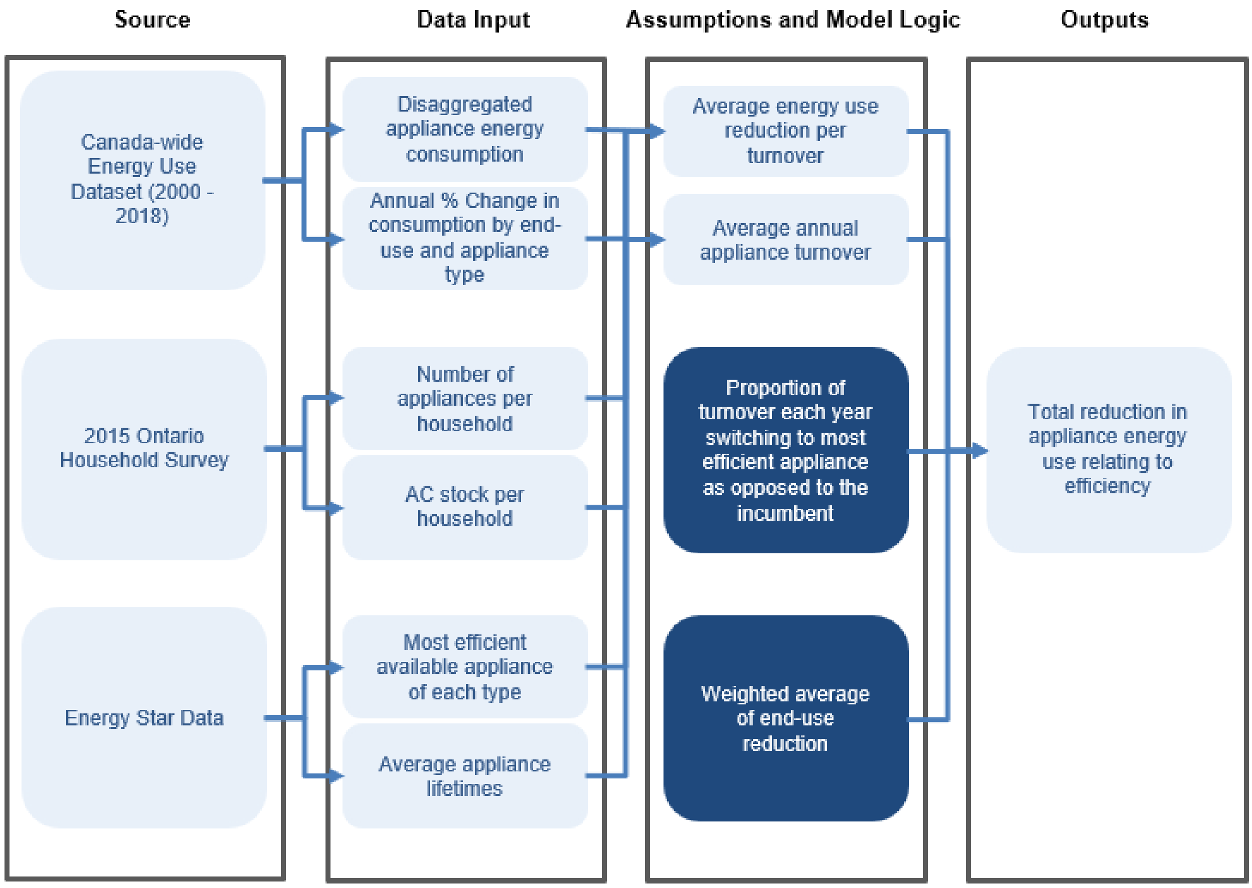


Figure 27: Domestic appliance efficiency projection methodology[17,18,19,20].

Using 2018 Conservation and Demand Management (CDM) data provided by Toronto Hydro, it was determined that the average participation rate of a residential appliance program was 1.5% of the total residential customers. In 2018, five residential appliance programs were available to consumers. As such, the Low scenario was formulated such that 7.5% of annual appliance turnover was to the most efficient appliance, in line with potential CDM intervention impacts. The remaining scenarios are summarized in Table 5 below.

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[17] National Resources Canada, Canada-wide Energy Use Dataset | Energy Efficiency Trends Analysis Tables, 2000 – 2018
[18] National Resources Canada, 2015 Survey of Household Energy Use (SHEU-2015) Data Tables , 2015
[19] National Resources Canada, Energy Star | Choosing and Using Appliances With EnerGuide, 2013

Table 5: Scenario assumptions for domestic appliance efficiency projections.

Scenario	Description	Energy use reduction by 2050
Low	1.5% x 5 = 7.5% of annual turnovers switch to most efficient appliance	11%
Medium	Intermediate reduction between Low and High	24%
High	100% of appliances are turned over to most efficient by 2050	37%

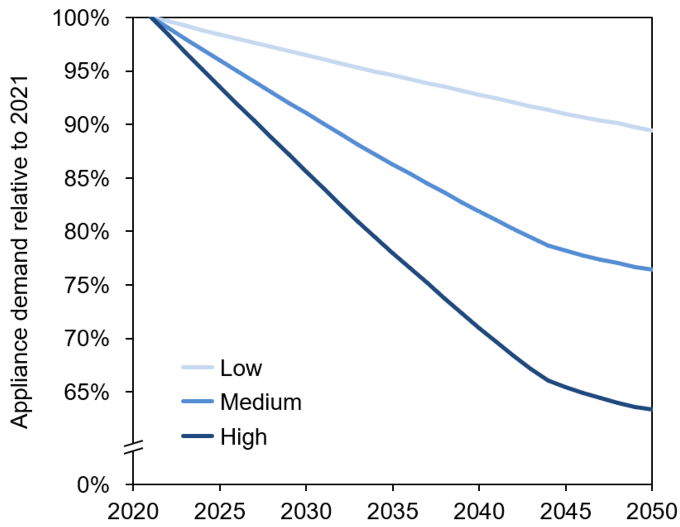


Figure 28: Domestic appliance (non-heat) energy demand reduction relative to 2021.

As shown in Figure 27, a key data input in generating the domestic appliance energy efficiency projections was the average number of appliances per household. These data were obtained from the National Comprehensive Energy Use Database[20] and are shown in Table 6.

Table 6: Historic average number of appliances per household.

Appliance	Per household stock (2018)
Refrigerator	1.28
Freezer	0.50
Dishwasher	0.57
Clothes washer	0.76
Clothes dryer	0.79
Range	1.00
Air conditioning (AC)	0.86[21]
Small appliances	17.35

An appliance growth projection was generated, where the per household stock for all appliances (excluding AC and small appliances) was assumed to be constant throughout the modelled time period, based on the observation that there was minimal historic growth in these appliances. Conversely, for AC and small appliances, a continuation of recent historical trends was assumed as shown in Figure 29.

[20] Natural Resources Canada, Residential Sector Canada Table 37: Appliance Stock by Appliance Type and Energy Source

[21] Toronto Public Health, Protecting Vulnerable People from Health Impacts of Extreme Heat, July 2011

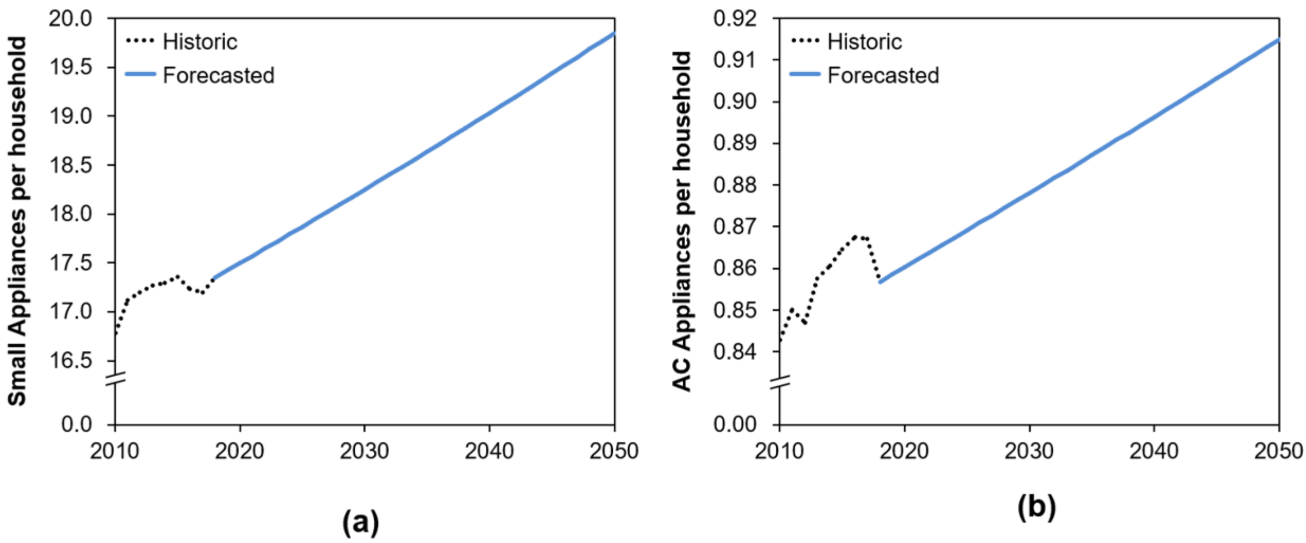


Figure 29: Growth projection for (a) small appliances and (b) AC units per household.

Industrial and Commercial Electricity (Non-Heat) Efficiency Projection

Figure 30 shows the high-level methodology used to create the I&C electricity efficiency projections. The same methodology was utilized for the I&C thermal efficiency projection, discussed in further detail in Section 4.2.3.

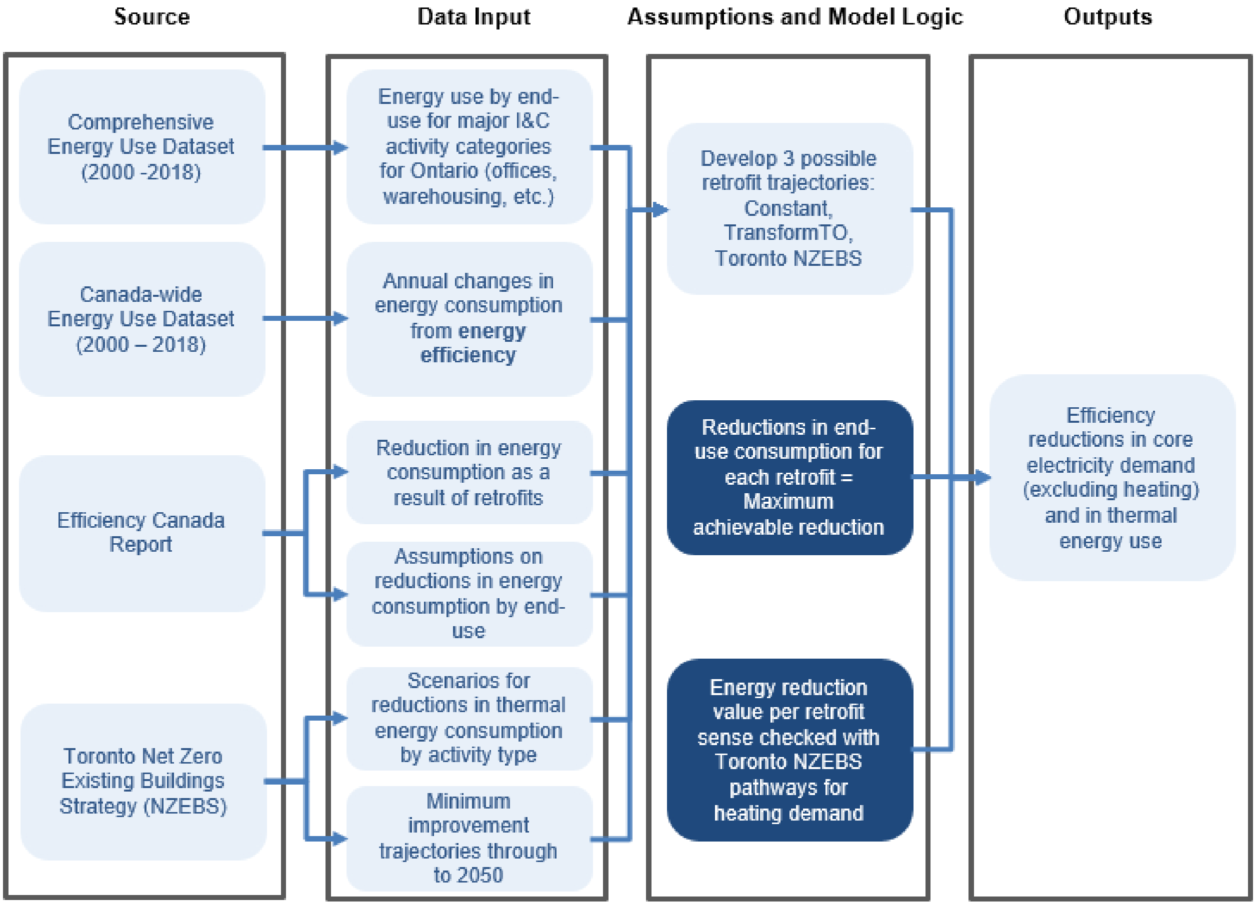


Figure 30: Methodology for I&C electricity and thermal efficiency Projections[22,23,24,25].

Canada-level data on the annual change in energy consumption from energy efficiency was used to develop the Low scenario, which follows a continuation of historic trends. For the Medium and High scenarios, energy use reductions were assumed to be driven by retrofits, with the reduction values by end-use taken from a report by Efficiency Canada and Carleton University[24]. The authors state that the retrofit reductions cited "go further than most current practice but stop well short of current best-practice deep retrofits", and thus can be categorized as an intermediate between incremental improvements and best in class improvements. The differentiation between the Medium and High scenarios were the retrofit rates, with the Medium scenario accomplishing 60% retrofits by 2050 and the High scenario achieving 100% retrofits in the same timeframe. Table 7 below summarizes the scenario descriptions that serve as the basis for the electricity efficiency projection. Figure 31 shows the resulting scenario projections out to 2050.

Table 7: Scenario description and electrical (non-heat) energy use reduction by 2050 relative to 2021.

Scenario	Description	Non-heat electrical reduction in 2050
Low	Continuation of historic energy efficiency trends	5%

[22] Natural Resources Canada Comprehensive Energy Use Database (2000 – 2018) | Commercial/Institutional Sector – Ontario
[23] Natural Resources Canada, Canada-wide Energy Use Database (2000 – 2018) | Total End-Use Sector - Energy Use Analysis
[24] Efficiency Canada and Carleton University, Canada's Climate Retrofit Mission, June 2021
[25] City of Toronto, City of Toronto NetZero Existing Buildings Strategy and Technical Appendix, 2021

Scenario	Description	Non-heat electrical reduction in 2050
Medium	Intermediate trend (66% retrofits by 2050)	18%
High	NZ40 rate (100% retrofits by 2050)	27%

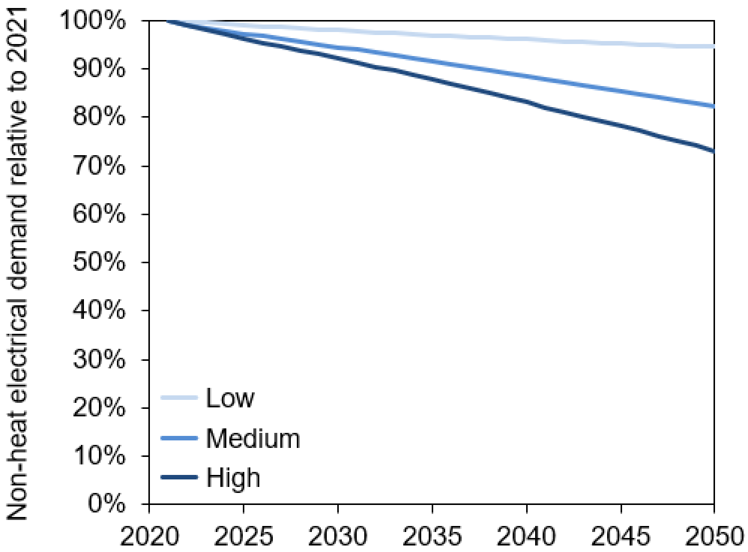


Figure 31: I&C projections for electricity (non-heat) energy demand reduction relative to 2021.

4.1.4 Flexibility Measures

Time-of-use (ToU) tariffs and energy storage are the primary flexibility measures relevant to core demand in this analysis. The approach to modelling the impact of ToU tariffs in the core demand projections is described below, while the modelling of domestic and I&C battery storage is discussed in more detail separately in section 4.5.

Under the Regulated Price Plan (RPP), a large fraction of domestic and small commercial customers (91%) in Toronto were on ToU tariffs before September 2020. In October 2020, the Consumer Choice regulation issued by the Ontario Energy Board (OEB) enabled price plan switching for RPP customers which has resulted in a reduction in the fraction of customers on the ToU plan[26], as shown in Figure 32.

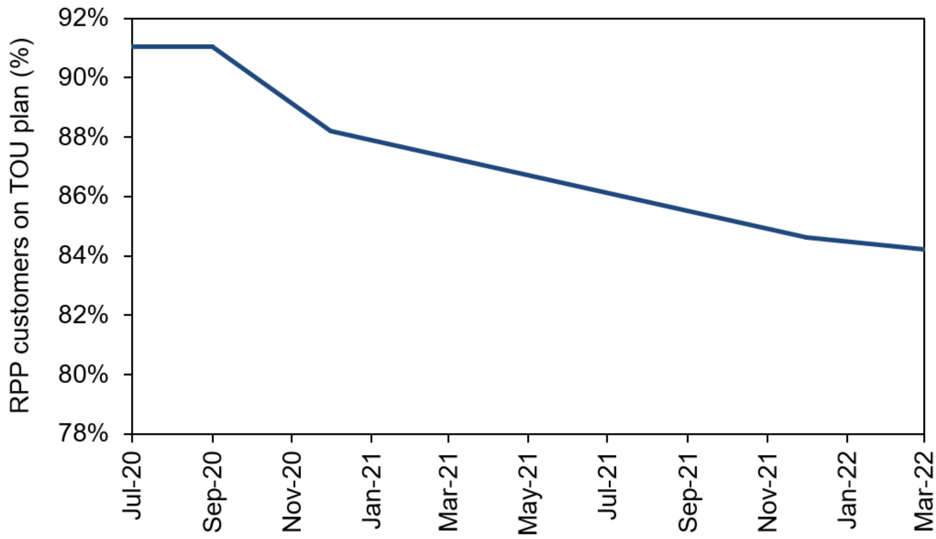


Figure 32. Price plan switching of eligible customers between ToU and tiered rate plans since the introduction of Consumer Choice, Ontario, Canada.

It is worth noting that a large portion of the observed switches occurred in the first few months after the regulation was implemented (47%). The latest available update on switching is from March 2022, which shows that 84% of eligible RPP customers remain on ToU tariffs. The current level of ToU tariff penetration across the Toronto Hydro network is captured in the modelling through the core demand profiles used (see Section 5.1). The March 2022 level of ToU tariff uptake is maintained throughout the modelling period for all scenarios.

[26] Ontario Energy Board (OEB), Frequency of Regulated Price Plan Switching Under Consumer Choice, 2021

4.2 Low Carbon Heating

There are two main pathways to decarbonize heat, each relying on varying levels of electrification and gas decarbonization. The key themes in each of these pathways are described in Figure 33.

Two main pathways to decarbonize heat

High Electrification	**Decarbonized Gas**
A high electrification scenario promotes electrification of heat using an increasingly decarbonized electricity grid. There is a high uptake of **heat pumps**. All heat is electrified, and the gas grid is decommissioned.	A decarbonized gas scenario promotes the conversion of the gas grid to hydrogen or other low carbon gases (e.g., biomethane). Buildings remain predominantly heated by **gas boilers and/or furnaces,** shifting from natural gas to low carbon alternatives.

In addition, **district heating** and **energy efficiency** can play a role in both pathways.

Figure 33: Heat pathway diagram.

The High Electrification and Decarbonized Gas scenarios represent two extremes of the future; in reality, the pathway for heat decarbonization in Canada, and Toronto particularly, could be a mix of these components, with different regions potentially opting for different technological solutions.

We developed scenarios for key drivers of the transition to low carbon heating, as laid out in Table 8. For energy efficiency and heating technologies, four scenarios representing incremental levels of ambition were generated using Element's consumer choice modelling (described in Section 4.2.1). The efficiency scenarios relate to the level of uptake of fabric improving efficiency measures among the region's building stock Note that "Early High" is used for heating technology uptake as opposed to "Very High" – this is because the scenario reaches the same level of heating technology deployment as the "High" scenario, but at a faster rate. As with other sectors, these technology specific uptake scenarios have then been mapped to a corresponding scenario world, as shown in Table 8.

Table 8: Scenario world mapping for low carbon heating.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Domestic thermal efficiency	Low	Medium	High	Low	Very High	Low
I&C thermal efficiency	Low	Medium	High	Low	Very High	Low
Domestic heating technologies	Low	Medium	High		Early High	
I&C heating technologies	Low	Medium	High		Early High	
Gas heating in 2050	High	Medium (due to hybrid heat pumps)	None		None	
Gas grid availability	Remains at current availability	Reduced utilization	Decommissioned by 2050		Decommissioned by 2040	

4.2.1 Modelling Approach

As discussed in Section 3.1, bottom-up consumer choice models were used to determine the uptake of decarbonized heating technologies. This analysis was predicated upon the locationally granular building stock trajectories (for domestic and non-domestic building types) described in Section 4.1.2. The domestic and I&C building trajectories were treated separately because their growth is driven by distinct factors.

Element Energy has a heating technology uptake model that assesses the business case of various heating technologies (Figure 34Figure 34) for different domestic and I&C building stock archetypes. In this model, the heating technologies are assumed to have a set lifetime (15 years for all scenarios), at the end of which the consumer chooses which technology to replace it with based on various factors. These factors include the following:

- Technology prices (capital costs and operational costs) including the available grants.
- Fuel and electricity costs.
- Thermal efficiencies for each archetype.
- Awareness of technology for domestic and I&C consumers.
- Willingness-to-pay for each archetype.
- Government policy.

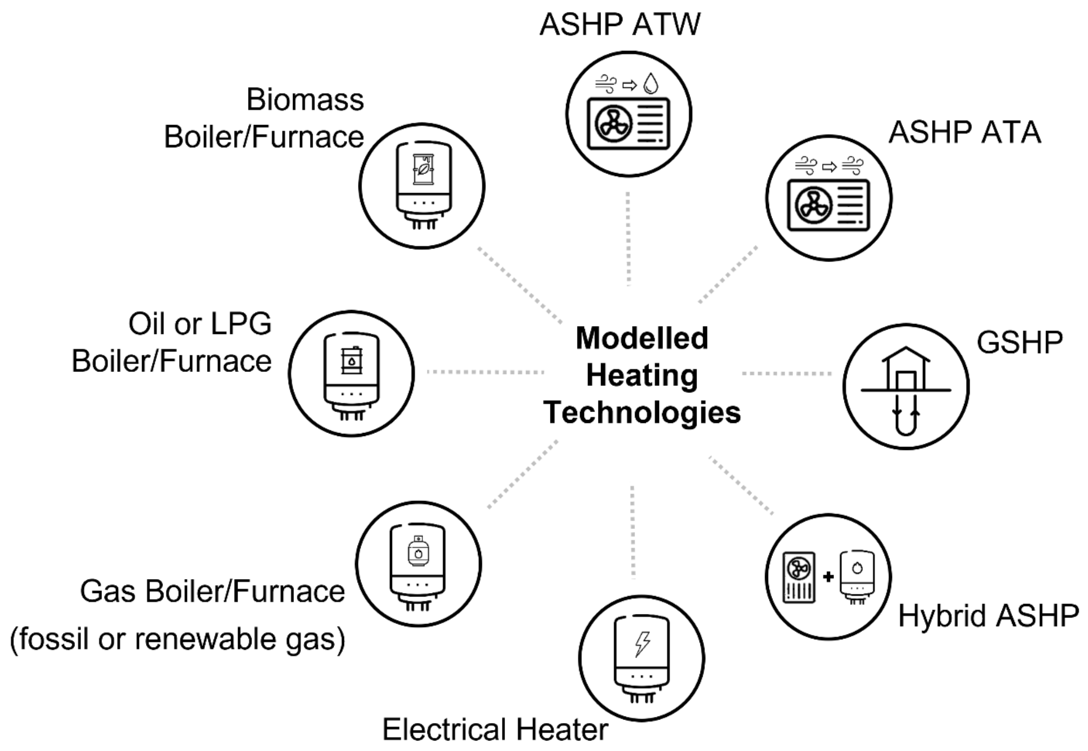


Figure 34: Modelled heating technologies.
Acronyms: ASHP ATW: air source heat pump – air to water; ASHP ATA: air source heat pump – air to air; GSHP: ground source heat pump; Hybrid ASHP: hybrid air source heat pump.

District heating is not classified as a distinct heat source in the consumer choice model, since the fundamental technologies used for heat generation are no different than those used in centralized applications; what differs is the distribution system. In addition to this, the driving factors leading to district heat uptake are more complex than for other low carbon heating options – uptake is related to variables beyond an individual consumer's choice or control, such as the heat density of the city, the proximity to existing or future significant sources of waste heat, or a region's planning laws. Considering Toronto specifically in conjunction with these general factors, two further points led to the decision to exclude district heating from our analysis of heat decarbonization in this case:

- Currently, fewer than 1% of buildings in Toronto are heated by district heating[3].
- Future rollout of district heating would affect the location and clustering of electrical loads, rather than the overall demand. At the geospatial resolution of this modelling (neighbourhoods and municipal stations), the impact of this is expected to be very small.

4.2.2 Policy Assumptions

As existing fossil fuel technologies are currently cheaper to install and run in many cases, top-down government intervention is assumed to be essential to drive uptake of decarbonized heating technologies.

IESO's Pathway to Decarbonization[27] reflects a ban on fossil fuel heating in new homes by 2030 and existing homes by 2035. This suggests that the most likely policy intervention going forward to decarbonize heat will be to phase out heating technologies that depend on high carbon fuels such as gas, oil and LPG. Element Energy's previous engagement with building-level heat professionals suggests that, if such policy interventions are to occur, they will first target new builds, followed by off-gas existing buildings, followed by on-gas existing buildings, depending on the general policy ambition.

[27] The Independent Electricity System Operator, Pathway to Decarbonization – Assumptions for Feedback, March 2022

Table 9 lists the assumed dates for when different existing heating technologies are phased out in order to reach net zero by either 2040 or 2050 depending on scenario. These dates apply to both domestic and I&C customers.

Table 9: Ban dates for choosing Business As Usual heating fuels in building types (new builds or existing builds).

Scenario	Existing heating fuel	New builds	Existing buildings	Ban date on Hybrid Heat Pump
Low	Gas	2035	No restrictions	No restrictions
	Oil & LPG	2035	2035	2035
Medium	Gas	2030	2035	No restrictions
	Oil & LPG	2030	2030	2030
High	Gas	2030	2035	2035
	Oil & LPG	2027	2027	2027
Early High	Gas	2025	2025	2025
	Oil & LPG	2025	2025	2025

Canada's Greener Homes Grant

The Canadian Greener Homes grant, effective from December 2020, grants up to $5,000 towards heat pumps and energy efficiency measures. The scheme can be used for a selection of low-carbon technologies, including those not used for heating (e.g. solar PV). The heat pump technologies that are supported by the scheme are listed below:

- Air-Source Heat Pump: Air-to-Air (ASHP ATA).
- Air-Source Heat Pump: Air-to-Water (ASHP ATW).
- Ground-Source Heat Pumps (GSHP).

There is currently no support for hybrid heat pumps under this scheme. The Greener Homes Grant is expected to last at least 7 years since its initiation, but this may be extended. Within our heating technology uptake scenarios, four policy scenarios were created describing a potential future for the Greener Homes Grant. These scenarios differ by level of support by technology, the heating technologies that are supported by the scheme and the scheme end date. The scenario mapping is shown in Table 10 below.

Table 10: The Greener Homes Grant policy support and duration assumed for each technology and scenario.

Scenario	GSHP	ASHP	Hybrid ASHP	End date
Low	$5,000	$4,000	$0	2027
Medium	$5,000	$4,000	$4,000	2030
High	$5,000	$4,000	$0	2030
Early High	$5,000	$4,000	$0	2035

4.2.3 Thermal Efficiency

Domestic Thermal Energy Efficiency Projection

For each building archetype, thermal efficiency trajectories were developed that then fed into the heat pump and load modelling on an archetype-specific basis. These trajectories are based on the following three components for each scenario:

- The baseline thermal demand of each archetype.
- The post-retrofit thermal demand of each archetype.
- The retrofit rate.

The baseline thermal demand was determined using data from the National Energy Use Database[28]. A post-retrofit thermal demand was then established for each archetype and scenario. For the Medium and High scenario, this is based on thermal demands after comprehensive building retrofits by building type and age based on a report by Efficiency Canada and Carleton University[24]. These were broadly aligned with post-retrofit demands for different building types from The City of Toronto's Net Zero Existing Buildings Strategy[29] (NZEBS), falling within the range of their *Recommended* and *Aggressive* scenarios. For the Very High scenario, which aligns with TransformTO's[3] Net Zero by 2040 (NZ40) scenario, deeper retrofits are assumed for each archetype, aligning with a total building energy efficiency gain of 75%. In the Low scenario, lower efficiency gains are assumed, and the post-retrofit thermal demand is aligned to TransformTO's Business as Planned (BAP) scenario, with a total building energy efficiency gain of 35%.

The retrofit rate represents the proportion of buildings retrofitted by year. The Low and Very High scenario retrofit rates are drawn from TransformTO BAP and NZ40, respectively. The High scenario retrofit rate is based upon the progress rate from NZEBS, while the Medium scenario retrofit rate sits midway between the Low and the High scenarios. Figure 35 shows the proportion of buildings retrofitted by 2050 for each scenario.

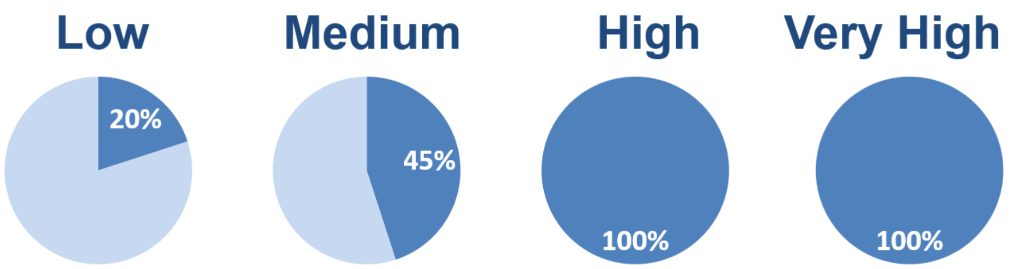


Figure 35: Proportion of domestic buildings retrofitted by 2050 by scenario.

The resulting thermal energy efficiency projections are shown below in Figure 36. Due to the deeper retrofits assumed in order to align the Very High scenario with TransformTO's NZ40 scenario, the overall thermal demand reduction achieved in the Very High scenario is higher than the citywide reduction of 73% put forth by the *Aggressive* scenario from the Toronto Net Zero Existing Buildings Strategy.

[28] Natural Resources Canada, National Energy Use Database – Ontario, 2018
[29] The City of Toronto, Net Zero Existing Buildings Strategy, May 2021

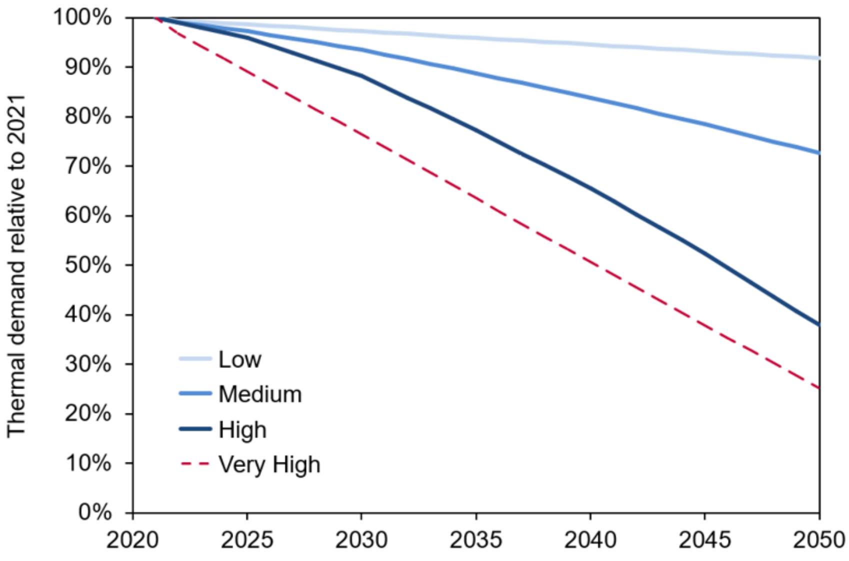


Figure 36: Domestic thermal energy efficiency projections out to 2050.

Industrial & Commercial Thermal Efficiency Projection

The baseline thermal demand by I&C archetype was determined using Ontario-level data from the Comprehensive Energy Use Dataset[28]. For the Low scenario, reductions in demand (and retrofit rate) are a continuation of energy use reductions from energy efficiency as taken from the Energy Efficiency Trends Analysis Tables of the National Energy Use Database[17]. The Medium and High scenarios base thermal demand reduction on retrofits, where the post-retrofit thermal demands by archetype were determined using the percentage reduction in thermal demand by end use from the Efficiency Canada and Carleton University report. These values are broadly aligned with the values from the *Recommended* pathway of The City of Toronto's Net Zero Existing Buildings Strategy. The retrofit rate for the High scenario is taken from the *Aggressive* pathway of The City of Toronto's Net Zero Existing Buildings Strategy, while the Medium scenario retrofit rate is the average of the BAP rate of TransformTO and the rate of the High scenario. Table 11 below shows the scenario descriptions that serve as the basis for the thermal efficiency projections. A Very High scenario was incorporated which matches the TransformTO NZ40 retrofit rate and retrofit reduction values. This represents a particularly ambitious scenario option since it exceeds the 60% reduction used in the *Aggressive* pathway of the Toronto Net Zero Existing Buildings Strategy which is based on "best in class" retrofits.

Table 11: Scenario description and thermal energy use reduction by 2050 relative to 2021.

Scenario	Description	Heating reduction in 2050
Low	Continuation of historic energy efficiency trends	10%
Medium	Intermediate trend (66% retrofits by 2050)	22%
High	NZ40 rate (100% retrofits by 2050)	33%
Very High	NZ40 rate and NZ40 reduction value	75%

The resulting thermal efficiency projections are shown below in Figure 37.

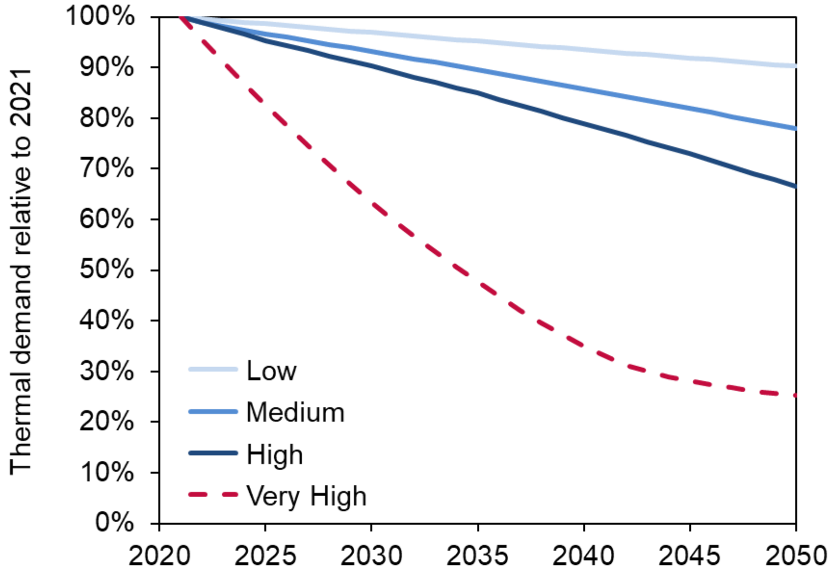


Figure 37: I&C thermal efficiency projections out to 2050.

4.2.4 Uptake Modelling Results

Element Energy's in-house consumer choice model was used to develop four scenarios for the uptake of low carbon heating across the domestic and I&C sectors, as described in Section 4.2.1. These scenarios represent a wide range of decarbonization ambition, resulting in varied levels of the uptake of heat pumps. The trajectories for the uptake of full electric heat pumps are shown below in Figure 38. The following sections detail the modelling assumptions and results for each of these scenarios.

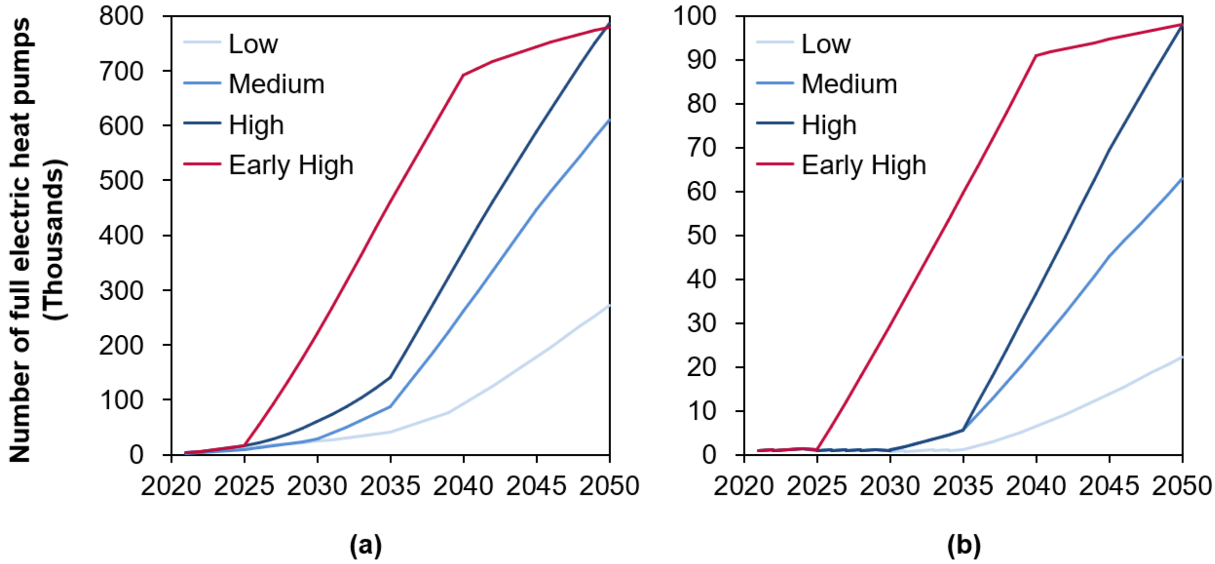


Figure 38: Comparison of full electric heat pumps modelled out to 2050 between scenarios for the (a) domestic and (b) I&C building stock.

Low Scenario - Steady Progression

In the Low scenario two policy interventions are considered, a ban on fossil fuel heating in new homes from 2035 and a ban on fossil fuel heating in off-gas properties from 2035 (Table 12Table 12). Additionally, the Greener Homes Grant is not assumed to last longer than the currently proposed duration of 7 years (from 2020). A low rollout in energy efficiency measures is modelled in this scenario. The resulting heating technology breakdown can be seen in Figure 39. This scenario fails to fully decarbonize the heating sector which still relies heavily on natural gas in 2050. The heat pumps that come into operation are predominantly in the new build and off gas grid sectors. Since there is no I&C sector support from the Greener Homes Grant, there is little financial motivation for heat pump uptake until policy forces the switch. This scenario suggests that without government intervention, the business case for gas heating will remain strong, resulting in low uptake of low-carbon heating technologies.

Table 12: Scenario assumptions for low-carbon heating technology uptake in the Low Scenario.

Heating technology	Date after which new builds can no longer choose heating fuel	Date after which existing buildings can no longer choose heating fuel	Date after which buildings can no longer choose a hybrid heat pump with heating fuel
Gas furnaces or boilers	2035	No restrictions	No restrictions
Other fossil fuel-based heaters	2035	2035	2035
Greener Homes Grant end date	2027	**Energy efficiency rollout scenario**	Low

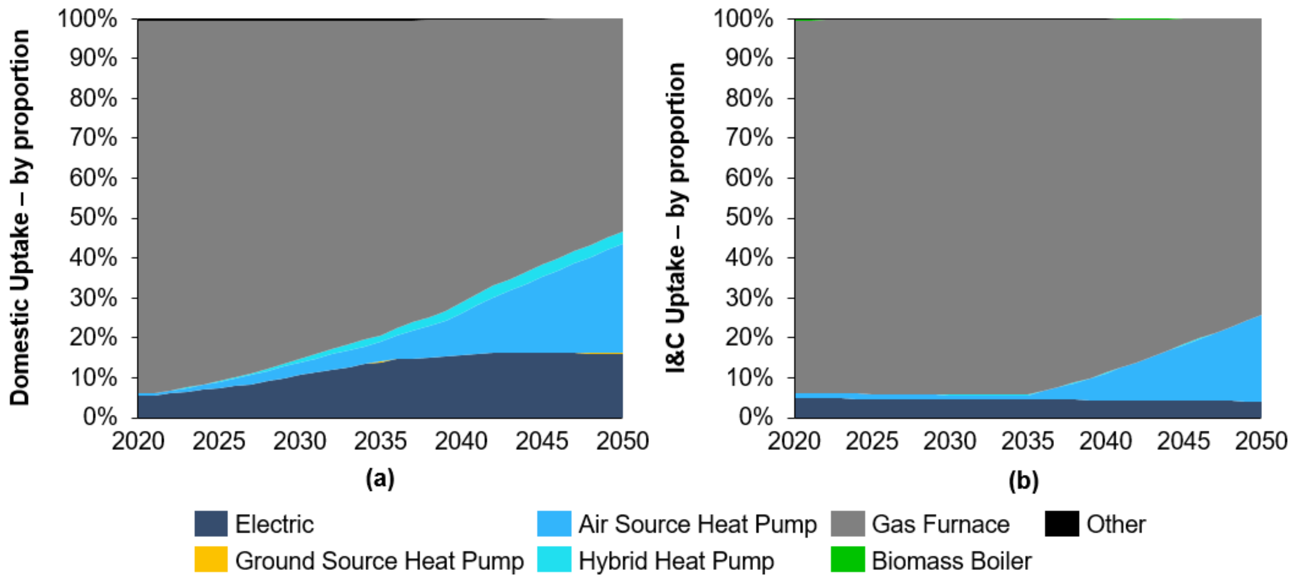


Figure 39: (a) Domestic and (b) I&C low carbon heating technology uptake - Low Scenario.

Medium Scenario – System Transformation

The Medium scenario is a gas-backed scenario and is based upon the *Hybrid Heating* pathway from The Canadian Gas Association's (CGA) report on pathways to achieving net zero building stock by 2050[30]. The report outlines three different decarbonization scenarios: *Efficiency*, *Hybrid Heating* and *Renewable Gases*. Each of these pathways are designed to meet net zero by 2050 by relying on the following factors to varying degrees depending on the scenario:

- Energy efficiency improvement programs.
- Stricter building regulations.
- Heat pumps (including hybrid heat pumps).
- Use of 'renewable gases', particularly renewable natural gas (RNG).
- Emissions offsets.

Table 13 shows the level of emissions reduction achieved in each of the three scenarios via the above drivers, according to the analysis.

Table 13: Canadian Gas Association Pathways showing the proportion of present-day emissions removed.

CGA Scenario	Gas demand reductions	Renewable gases	Emissions Offsets
Efficiency	43%	43%	14%
Hybrid Heating	56%	35%	9%
Renewable Gases	30%	55%	15%

The *Hybrid Heating* pathway has the lowest reliance on emissions offsets (as well as renewable natural gas) and was selected to inform the gas-backed Medium scenario in this analysis.

In the Medium scenario the ban on fossil fuel heating in new builds is brought forward to 2030 and existing off-gas properties can no longer choose non-gas fossil fuel heating from 2030 (Table 14Table 14). Existing on-gas properties are no longer able to select gas heating from 2035. To simulate the *Hybrid Heating* pathway in the consumer choice model, hybrid heat pumps are not phased-out from sales at this date, unlike in the other net zero compliant scenarios. Additionally, an extension to the Greener Homes Grant to support hybrid heat pumps as well as pure electric ones is modelled. A medium rollout of energy efficiency measures is modelled in this scenario.

Table 14: Scenario assumptions for low-carbon heating technology uptake in the Medium Scenario.

Heating technology	Date after which new builds can no longer choose heating fuel	Date after which existing buildings can no longer choose heating fuel	Date after which buildings can no longer choose a hybrid heat pump with heating fuel
Gas furnaces or boilers	2030	2035	No restrictions
Other fossil fuel-based heaters	2030	2030	2030
Greener Homes Grant end date	2030 with hybrids	**Energy efficiency rollout scenario**	Medium

[30] The Canadian Gas Association, Potential Gas Pathways to Support Net Zero Buildings in Canada, October 2021

In the Medium scenario a considerable proportion of heating systems in both the domestic and I&C sectors switch to hybrid heat pumps, making use of retained gas infrastructure (Figure 40Figure 40). It is worth noting that the source of the gas is not modelled for these scenarios; however, for the Medium scenario to be consistent with the 2050 net zero target, all fossil natural gas would need to be replaced with renewable natural gas, per the CGA's recommendations.

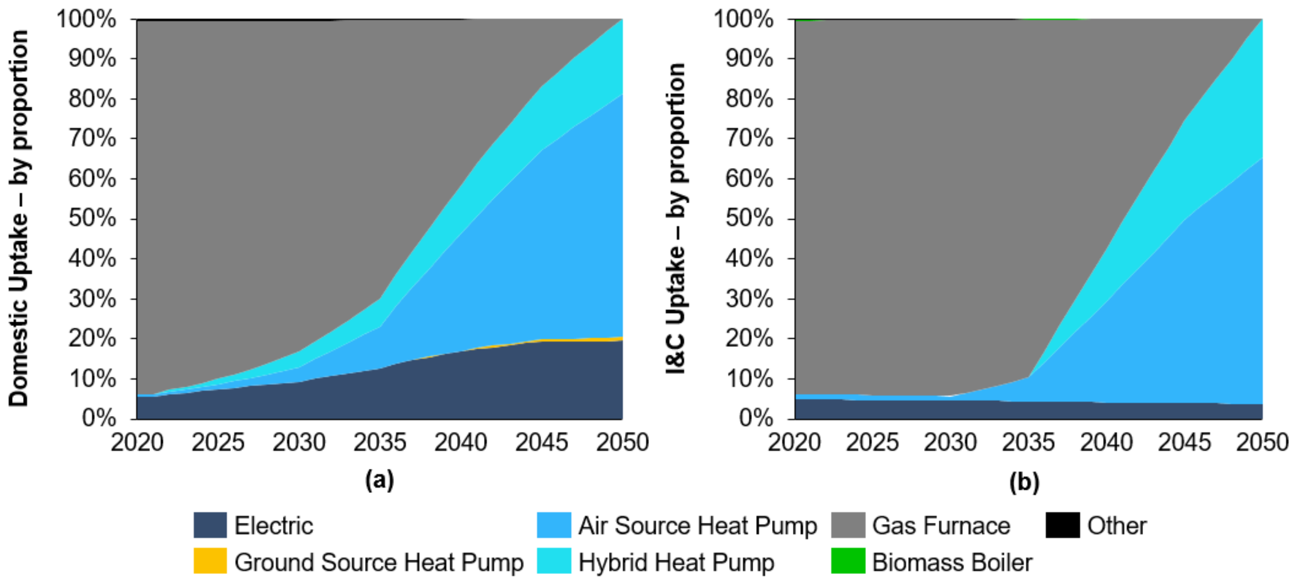


Figure 40: (a) Domestic and (b) I&C low carbon heating technology uptake - Medium Scenario.

High Scenario – Consumer Transformation

The High scenario relies on the full electrification of the heating sector. Like the Medium scenario, an extension to the Greener Homes Grant to 2030 is modelled; however, this is modelled without the additional support for hybrid heat pumps in this scenario. A ban on gas heating in new builds is enforced in 2030, with the ban on other fossil fuel heating brought forward to 2027, for existing and new builds (Table 15Table 15). In 2035, a ban on gas boilers is enforced for existing buildings, which includes switching to gas hybrid heat pumps. These bans, coupled with an assumption of a 15-year average lifetime of heating technologies, ensures a complete phase out of gas heating by 2050. A high rollout of energy efficiency measures is modelled in the High scenario. The resulting heating breakdown in Figure 41 shows that, for both the domestic and I&C sectors, the entire building stock is either using electric heating or fully electric heat pumps by 2050.

Table 15: Scenario assumptions for low-carbon heating technology uptake in the High Scenario.

Heating technology	Date after which new builds can no longer choose heating fuel	Date after which existing buildings can no longer choose heating fuel	Date after which buildings can no longer choose a hybrid heat pump with heating fuel
Gas furnaces or boilers	2030	2035	2035
Other fossil fuel-based heaters	2027	2027	2027
Greener Homes Grant end date	2030	**Energy efficiency rollout scenario**	High

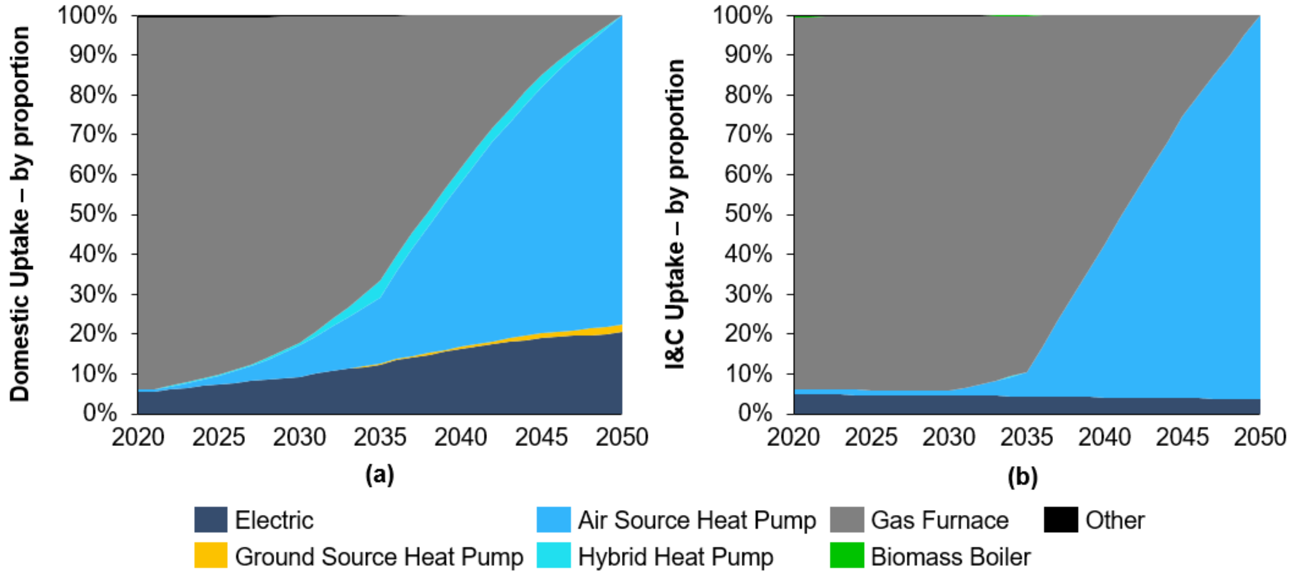


Figure 41: (a) Domestic and (b) I&C low carbon heating technology uptake - High Scenario.

Early High – Net Zero 2040

The Early High scenario reflects the highest government ambition in the scenarios modelled, with a 2040 net zero target. The scenario assumptions used in this scenario reflect early government action, with an all-encompassing ban on gas and other fossil fuel heating in 2025. The Early High scenario assumes a further extension of the Greener Homes Grant beyond the Medium and High scenarios to 2035, without any support for hybrid heat pumps (Table 16Table 16). A very high rollout of energy efficiency measures is also modelled in this scenario. The resulting heating technology breakdown in Figure 42 shows a fully electrified heating system by 2040 in both the domestic and I&C sectors.

Table 16: Scenario assumptions for low-carbon heating technology uptake in the Early High Scenario.

Heating technology	Date after which new builds can no longer choose heating fuel	Date after which existing buildings can no longer choose heating fuel	Date after which buildings can no longer choose a hybrid heat pump with heating fuel
Gas furnaces or boilers	2025	2025	2025
Other fossil fuel-based heaters	2025	2025	2025
Greener Homes Grant end date	2035	**Energy efficiency rollout scenario**	Very High

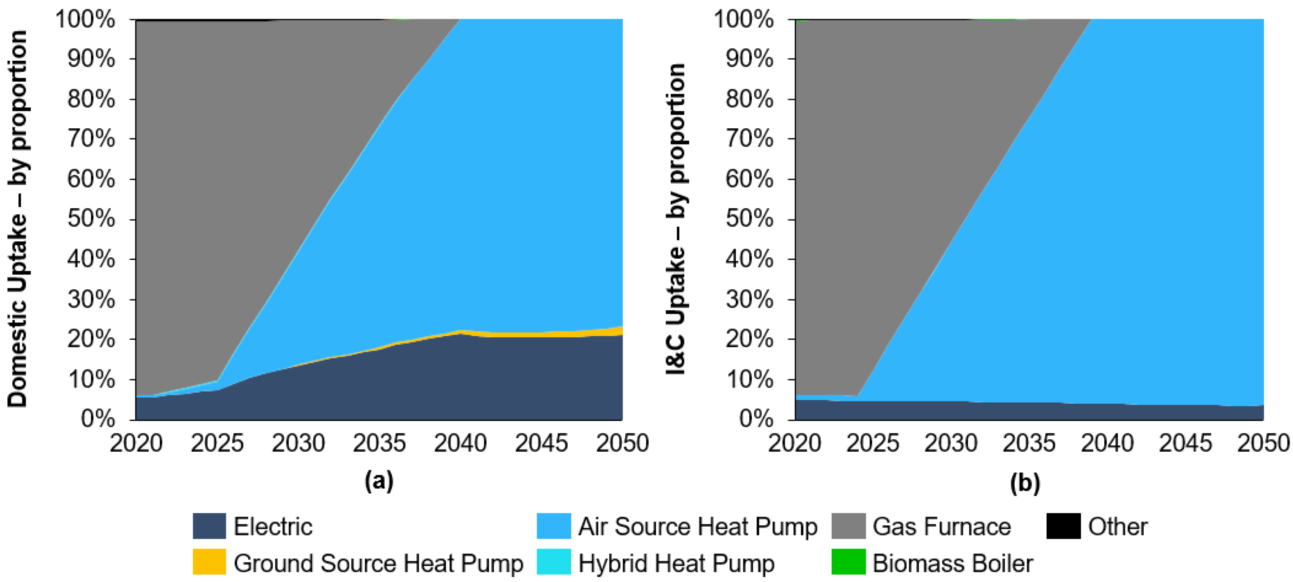


Figure 42: (a) Domestic and I&C (b) Low carbon heating technology uptake - Early High Scenario.

4.3 Electrification of Transport

There are several modes of transport relevant to Toronto, and in a similar manner to domestic and I&C buildings, different factors and market forces influence the manner in which different transport segments will decarbonize. Hence the penetration of electric vehicles (EVs) for each segment may differ in a given scenario world. The different sizes and requirements of transport types also lead to different technology mixes within sectors once decarbonized, as well as different assumptions for the energy required per unit of distance travelled. The main technology routes considered in the scenarios are summarized below in Figure 43.

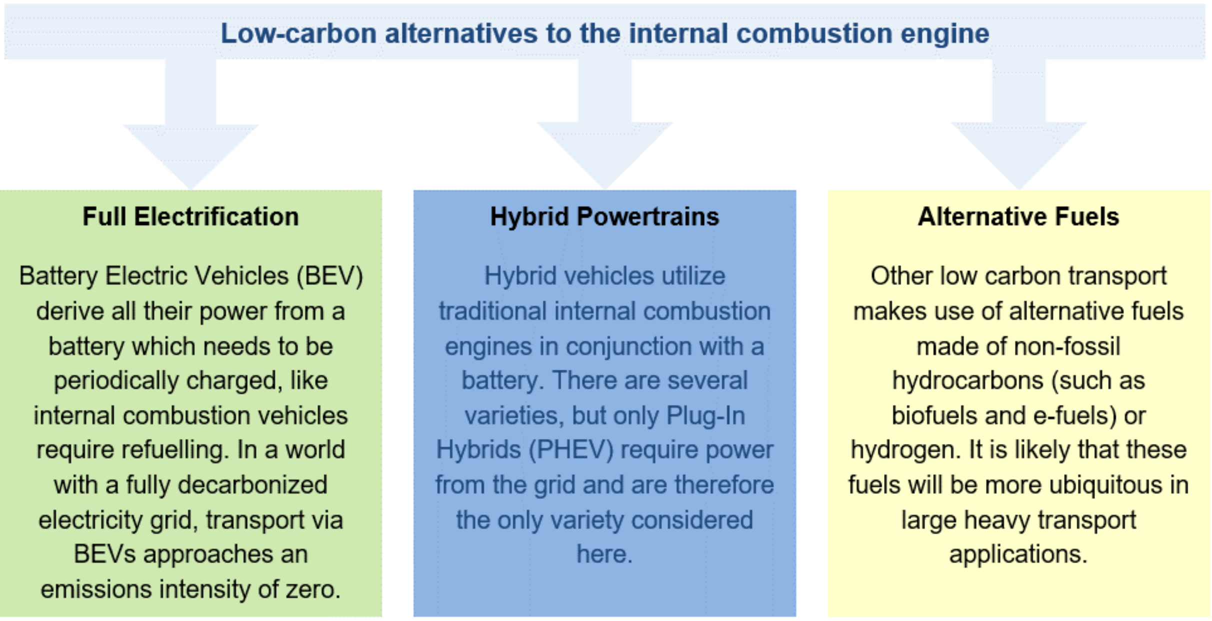


Figure 43: Main transport decarbonization pathways.

For the purposes of this analysis, transport has been segmented into Cars and Light Trucks, Medium- and Heavy-Duty Trucks, Buses, and Rail. Section 4.3.1 explains the electric vehicle uptake modelling process in more depth, while Section 4.3.6 gives an overview of how charging demand from these vehicles is allocated across the network. A summary of the penetration of electrified transport solutions in each of the four scenario worlds is given below in Table 17. The assumptions contained within each scenario are detailed in Sections 4.3.2 to 4.3.5 and 4.3.7.

Table 17: Scenario world mapping for transport electrification.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Cars and Light Trucks	Low	Medium	Medium		High	
Medium- and Heavy-Duty Trucks	Low	Medium	Medium		High	
Buses	Low	Medium	Medium		High	
Rail	Single Projection					
Smart Charging & V2G	Low	Medium	High	Low	High	Low

4.3.1 Modelling Approach

Electric Car Consumer Model (ECCo)

Element Energy's "Electric Car Consumer model" (ECCo) was used to generate bottom-up technology uptake scenarios for cars and light trucks, which consist of a varying mixture of full electric, hybrid and alternative-fuels based transport options. The model splits the private-individual and corporate-fleet customer bases into 18 archetypes based on attributes such as affluence and willingness-to-pay. The model then contains a parametric representation of consumer behaviour which was developed based on primary research conducted on a sample of 2,000 new car buyers. Within the model, consumers are "presented" with showrooms of future vehicles. Based on the real-world behaviour of the survey participants and the characteristics of consumer types within the model, the model reaches a purchase decision for each modelled individual which is likely to reflect real behaviour. For each model year the different consumer archetypes purchase an array of powertrains, which are typically observed to trend towards low-carbon options over time as the cost of these options fall. These results are then aggregated across all customer archetypes and converted to a total number of new car sales each year, which can also be converted to an overall share of the car stock held by a given technology.

Element Energy has refined this model over the course of the last decade, and it has been used extensively by clients in the UK including the Department for Transport and several electricity distribution businesses. The consumer choice approach it utilizes has consistently been shown to be more effective and accurate than other common approaches such as diffusion models and cost-comparisons. Figure 44 illustrates a high-level overview of the inputs and outputs of ECCo's modelling process.

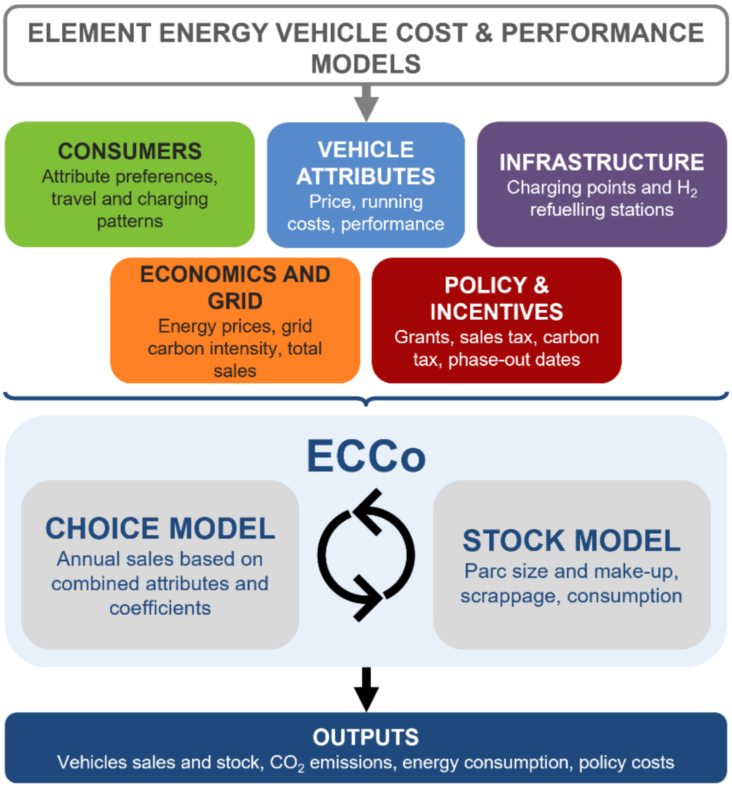


Figure 44: Schematic showing the process utilized by the ECCo model.

The modelling was tailored specifically to reflect the car ownership rates for different vehicle types in Canada and the physical attributes of the car types were also tailored to reflect the averages seen in the Canadian market. Inputs relating to vehicle economics such as tax rates, policy incentives and energy prices were aligned to those applicable in Toronto, including the Canadian Government's incentives for zero-emissions vehicles (iZEV) scheme[31] (the assumptions used align with April 2022 policies). Details of Toronto's infrastructure (such as gas station and charge point locations) were also taken as an input.

This process was able to produce detailed Low, Medium, and High electrification uptake scenarios for Toronto's car and light truck stocks, containing a detailed breakdown of the percentage share of battery electric vehicles (BEVs), plug-in hybrid electric vehicles (PHEVs) and other fuel types prevalent within the transport stock from the base year (2021) to 2050.

Base Year Vehicle Stock

The base year car and truck stock in Toronto and its composition was found from a range of data sources. Statistics Canada publishes provincial level registration data[32] which splits the stock by car type (passenger vehicle, pickup trucks, etc.) and powertrain (gasoline, diesel, battery electric, etc.). Vehicles are also often split into classes for the purposes of analysis and legislation. For this study, the United States Federal Highways Agency system for car and truck classification is used, where vehicles are assigned to one of eight generic classes. Classes 1-2 contain passenger cars, light trucks, sports utility vehicles (SUVs) and people-carriers, while vehicles in classes 3-8 are medium- and heavy-duty trucks. The separate treatment of different vehicle classes is important to this analysis because the energy consumed per unit distance travelled by an EV, which is a key driver in the uptake model, differs between classes.

It is worth noting that the available data for Toronto lacked detail pertaining to specific use-cases or classes of individual vehicles, apart from a 2016 dataset from the Ontario Data Catalogue[33] which details the stock of commercial and private vehicles (with no additional granularity). Therefore, it has been assumed that the full population of private vehicles from this dataset consisted of classes 1-2 only, while all commercial stock consisted of classes 3-8. This is a reasonable assumption since the vehicle types in classes 1-2 and 3-8 are most frequently used in private and commercial capacities, respectively. In reality, there will be some overlap which is not possible to capture in this analysis.

In lieu of Toronto level data which could provide a more granular classification of the commercial vehicles, a provincial level breakdown published by Statistics Canada[32] has been used to derive the composition of the stock. This dataset categorizes vehicles by weight brackets, rather than vehicles class. As such, vehicles weighing less than 4.5 tonnes were categorized as classes 1-2 (Cars and Light Trucks); vehicles weighing between 4.5 and 15 tonnes were mapped to classes 3-7 (Medium-Duty Trucks); while vehicles weighing more than 15 tonnes were classified as class 8 (Heavy-Duty Trucks, such as semi-trailer trucks). The breakdown of the stock at the Ontario level has been assumed to be equivalent to that of Toronto.

In addition, the vehicle stock is further split into BEVs, PHEVs and non-EVs. This was based on Ontario level data on zero emission vehicle sales from 2017 onwards, also from Statistics Canada[34]. The implicit assumption within this is that all vehicles in this dataset have remained operational until the base year. The overall process is illustrated below in Figure 45.

TransformTO data[3] was used to derive an annual growth factor for the stock of cars and light trucks, which was applied to the base year stock (derived as described above) to give an absolute total number of cars and light trucks in the city each year. The total stock growth trend does not vary between scenarios.

[31] Government of Canada, Incentives for Zero-Emissions Vehicles (iZEV), April 2022
[32] Statistics Canada, Vehicle registrations by type of vehicle, September 2020
[33] Ontario Data Catalogue, Vehicle Population Data 2016, March 2019
[34] Statistics Canada, New zero-emission vehicle registrations, January 2022

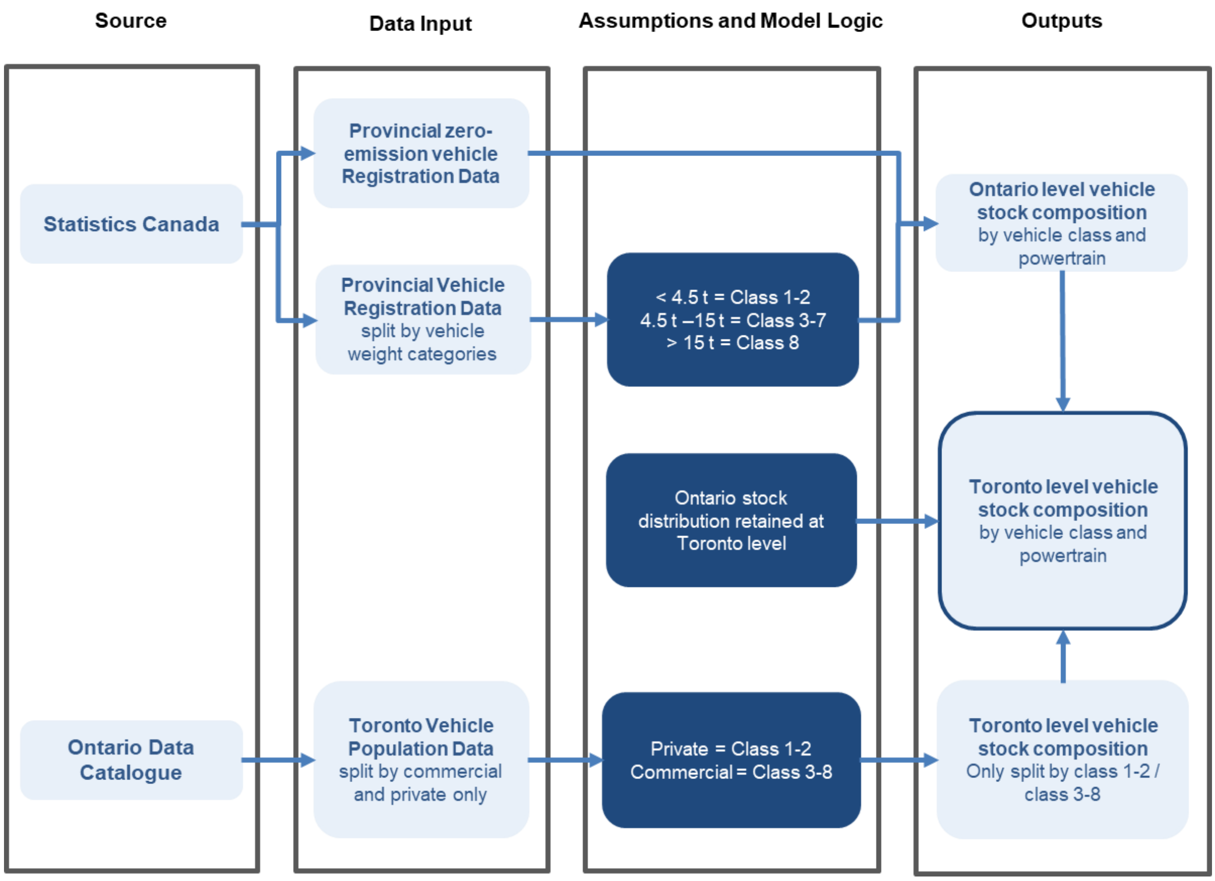


Figure 45: Methodology for deriving Toronto vehicle stock (cars and all truck types).

The bus stock in Toronto is owned and operated by the Toronto Transit Commission (TTC), who publish data regarding the makeup of their fleet including models, powertrains, age and depot locations in their annual Service Summary[35].

As of January 2022, there were 2,357 buses operational in the city, 79% of which were diesel powered. These buses span nine bus depots across Toronto. Under the assumption that all BEV and PHEV buses would charge solely at their designated depots, it is foreseeable that the peak impact of buses in specific areas of the grid could be significant, and hence is worthy of further analysis as described in Section 4.3.4.

[35] Toronto Transit Commission, Service Summary 2021, January 2022

4.3.2 Cars and Light Trucks

ECCo was used to model the development of the car stock from the common starting point derived as described in Section 4.3.1. By varying the assumptions related to policy, vehicles costs and infrastructure, three uptake scenarios for BEVs and PHEVs were developed representing a range of ambition levels. The trajectory for the total number of these types of cars in Toronto is shown below in Figure 46. The mapping of these scenarios to the overall scenario worlds is included in Table 17.

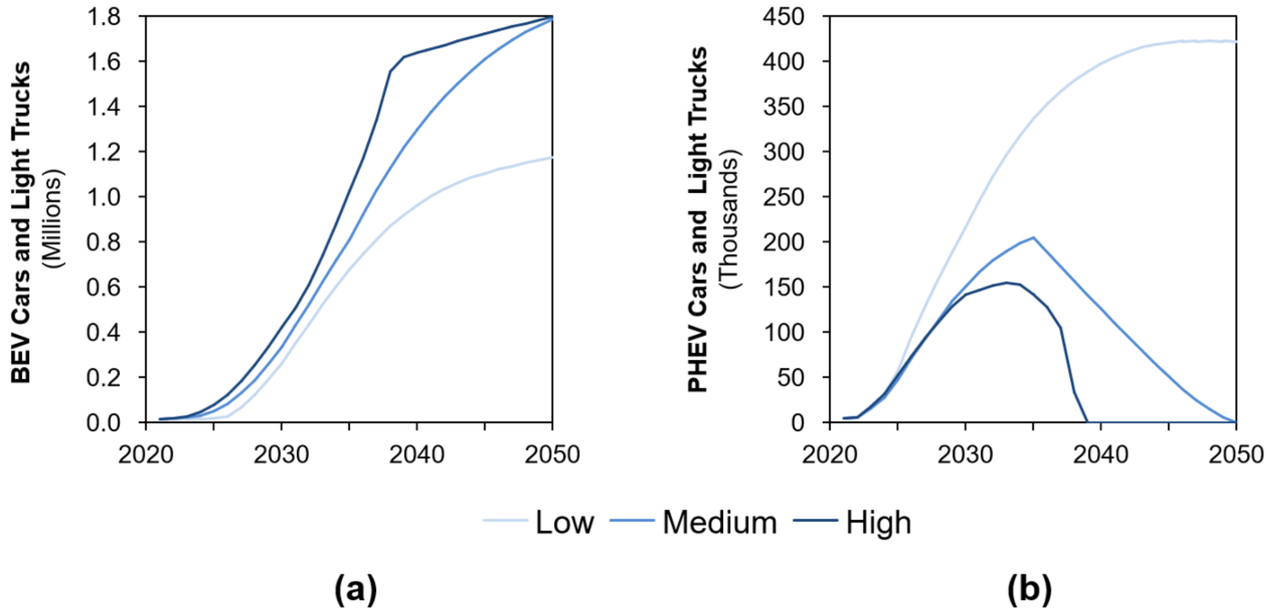


Figure 46: Comparison of Low, Medium and High stock profiles for (a) BEV and (b) PHEV cars and light trucks.

The above figure shows that the Medium and High scenarios differ primarily in the pace of their rollout of BEVs, with the Medium scenario relying more heavily on PHEVs as a transitional technology and for longer than the High scenario. However, the end states of both scenarios are comparable, with nearly 100% of the stock becoming fully electrified in both – meaning a rapid phase-out of hybrid and internal-combustion vehicles through the 2030s and 2040s.

Meanwhile, the Low scenario represents a markedly different view of the future of the transport sector. In this scenario, Toronto does not phase out hybrid or non-electric vehicles by 2050, implying a significant continued reliance on fossil fuels.

The assumptions underpinning each of the above trajectories, as well as a more detailed view of the stock breakdown in each case, are given below.

Low Scenario – Steady Progression

Table 18 describes the assumptions used in the Low scenario. A combination of low fossil fuel prices and high battery costs means that adoption of an EV would likely not be economically favourable for most consumers. Meanwhile, there is no top-down policy initiative established which could galvanize activity in the market, and as a result uptake is limited. In addition, the introduction of BEV SUVs and light trucks is delayed until 2023 and 2025, respectively, reflecting potential near-term supply constraints.

Table 18: Assumptions in Low electric transport uptake scenario.

Input		Assumption
Fuel Cost		Low crude price; current carbon tax policies[36]
Battery Cost		BNEF 2021; "High" price until 2024[37]
Non-zero emissions vehicles (non-ZEV) ban		N/A
Accelerated Non-ZEV removal period		N/A
Delay BEV introduction until	Cars	N/A
	SUVs	2023
	Light trucks	2025

Figure 47 shows the composition of Toronto's EV stock in the Low scenario, showing the continued reliance on non-BEVs and the stalled introduction of BEV SUVs and light trucks until the mid 2020s.

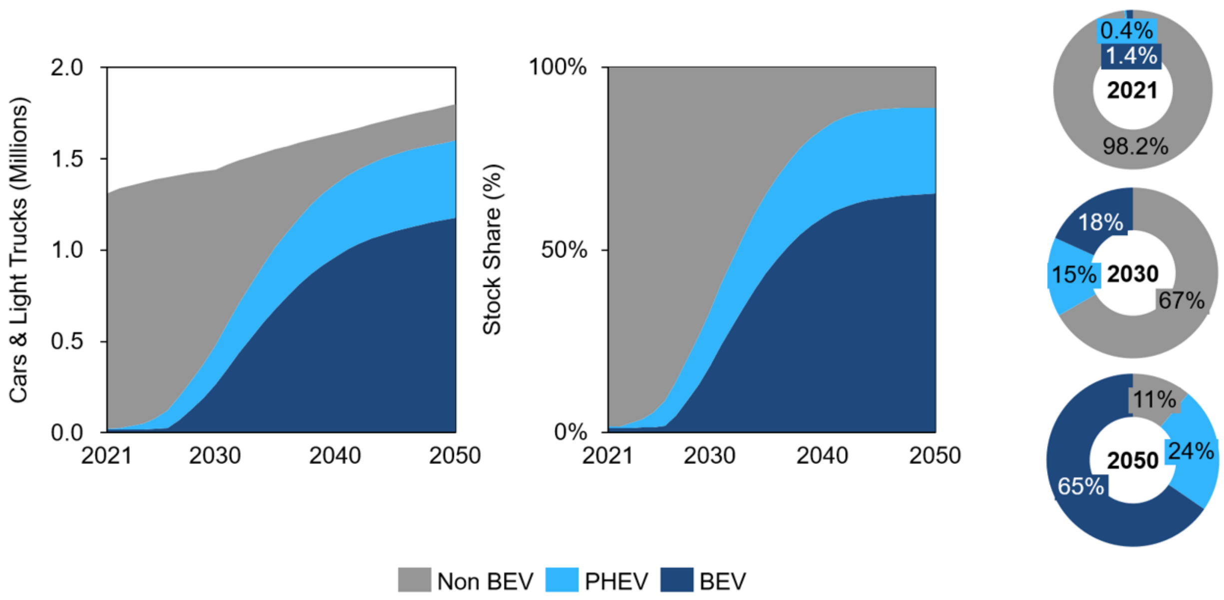


Figure 47: Low EV stock scenario – technology breakdown.

[36] Canada Energy Regulator, Canada's Energy Future, 2021
[37] Bloomberg NEF, Electric Vehicle Outlook, 2021

Medium Scenario – System Transformation & Consumer Transformation

Table 19 contains details the assumptions within the Medium scenario. As with the Low scenario, it is assumed that oil prices are low while battery prices remain high; but a non-ZEV sales ban is enacted from 2035 onwards. In addition, carbon taxation is increased from present levels, meaning the strength of the economic incentive to divest from fossil fuels increases. These factors have the effect of pushing consumers towards lower carbon options, resulting in a gradual and sustained phase out of non-BEVs. The effect of the non-ZEV phase out can be seen prominently on the PHEV trend in Figure 46b, where the curve begins to decline rapidly from 2035 onwards. Unlike the Low scenario, the Medium scenario does not delay the introduction of battery-electric SUVs and light-trucks.

Table 19: Assumptions in Medium electric transport uptake scenario.

Input		Assumption
Fuel Cost		Low crude price; evolving carbon tax policies[36]
Battery Cost		BNEF 2021; "High" price until 2024[37]
Non-ZEV ban		2035
Accelerated Non-ZEV removal period		N/A
Delay BEV uptake until	Cars	N/A
	SUVs	
	Light trucks	

Figure 48 illustrates the composition of Toronto's EV stock in the Medium scenario, showing the near complete decarbonization of this segment of transport by 2050.

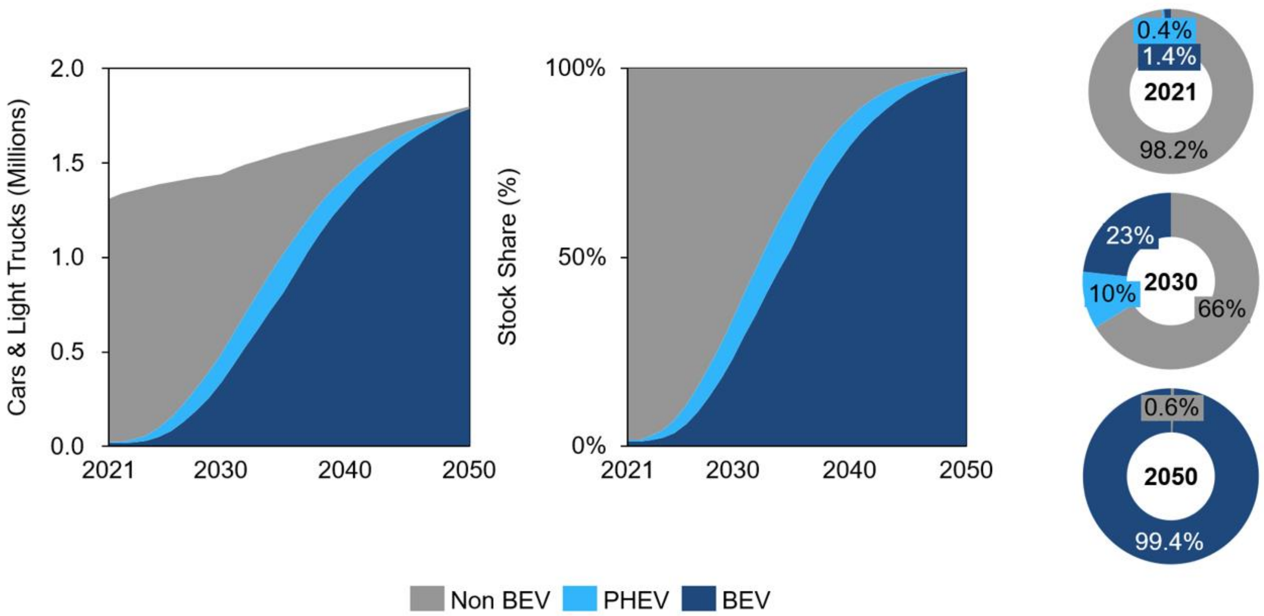


Figure 48: Medium EV stock scenario – technology breakdown.

High Scenario – Net Zero 2040

The High scenario, utilized in the Net Zero 2040 scenario world, is the most ambitious of the three scenarios. The High scenario assumes that fuel prices are high and battery costs are more favourable, meaning that consumers are more likely to decide to invest in an EV given the improved economics of this purchase decision. The carbon taxation scheme used in the Medium scenario is also retained here. Further, the non-ZEV ban applied in the Medium scenario is brought forward to 2030 (see Figure 46b) and is followed by a period of accelerated non-ZEV removal from Toronto to meet the 2040 net zero target. This could potentially be implemented via a policy mechanism such as a scrappage scheme or similar intervention. Table 20 summarizes the assumptions used in the High scenario.

Table 20: Assumptions in High electric transport uptake scenario.

Input		Assumption
Fuel Cost		High crude price; evolving carbon tax policies[36]
Battery Cost		BNEF 2021[37]
Non-ZEV ban		2030
Accelerated Non-ZEV removal period		2030-40
Delay BEV uptake until	Cars	N/A
	SUVs	
	Light trucks	

Figure 48 illustrates the composition of Toronto's EV stock in the High scenario, showing the total decarbonization of this segment of transport by 2040.

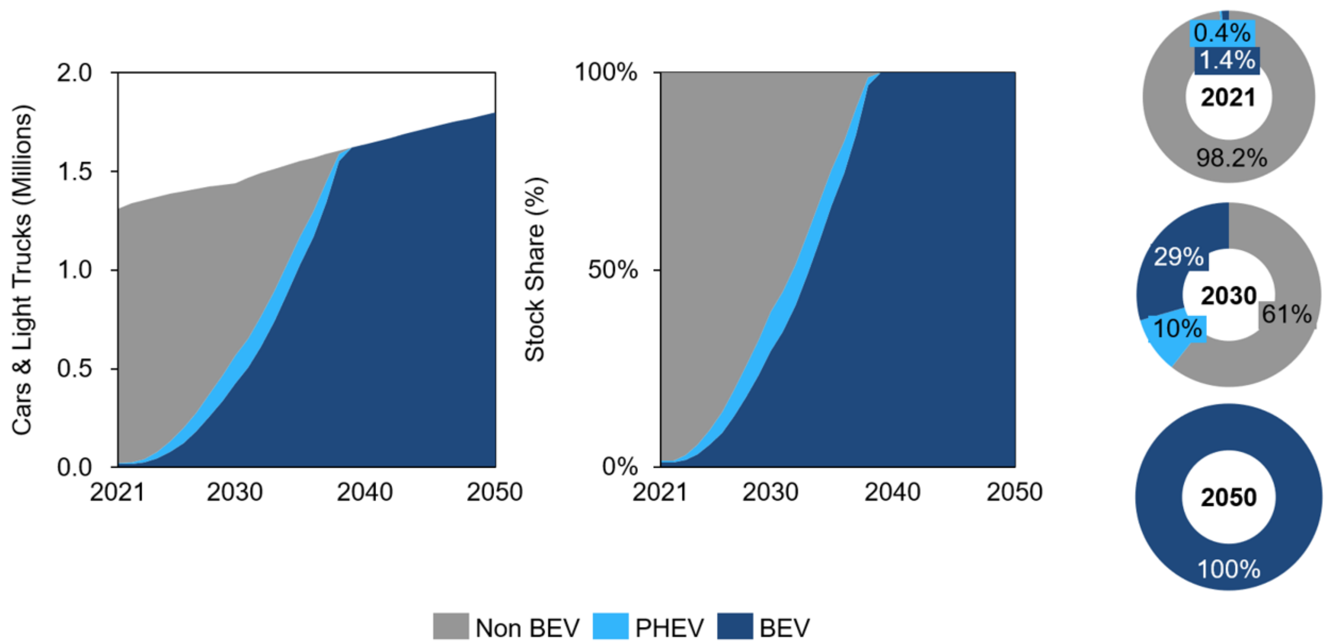


Figure 49:High EV stock scenario – technology breakdown.

4.3.3 Medium- and Heavy-Duty Trucks

The Low, Medium and High uptake scenarios for medium- and heavy-duty trucks are based on the assumptions listed below in Table 21.

Table 21: Truck uptake scenario assumptions.

Scenario	Scenario Narrative
Low	• 50% of truck sales by 2040 are ZEV • 100% of truck sales by 2050 are ZEV
Medium	• 30% of truck sales by 2030 are ZEV • 100% of truck sales by 2040 are ZEV • This aligns with Canadian Federal sales targets[38]
High	• Follows the ambitious targets of the California Air Resource Board to 2035[39] – see Figure 50 • Remaining non-ZEVs are all removed by 2040, by schemes such as scrappage bonuses.

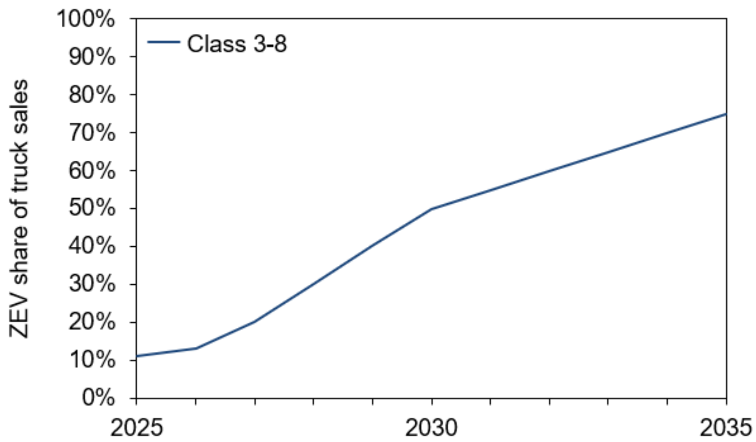


Figure 50: California Air Resource Board ZEV truck sales targets to 2035[39].

Figure 51 shows the three uptake scenarios developed using the above assumptions for class 3-7 and class 8 trucks separately. Again, these categories have been modelled separately because of their significantly different characteristics due to their weight. Principal among these differences is the energy consumed per unit of distance travelled (kWh/km). In general, the uptake of class 8 trucks (the largest commercial vehicles, such as semi-trailer trucks) leads their smaller counterparts by about two years. This is because it is assumed that the life span of such heavier vehicles is shorter and so they are replaced more frequently, meaning more of the stock is ready to be upgraded to low-carbon alternatives more quickly.

Somewhat similarly to the car and light-truck uptake trajectories described in Section 4.3.2, the Medium and High scenarios for medium and heavy trucks differ primarily in the rate at which full decarbonization of the stock is realized by 2050. Alternatively, in the Low scenario, the level of decarbonization achieved over the time horizon of this analysis is less complete. This is because in the Low scenario it takes until 2050 for all medium- and heavy-duty truck sales to be BEVs – so there is still a significant portion of the stock which consists of non-BEVs.

[38] Government of Canada, Incentives for Medium- and Heavy-Duty Zero-Emission Vehicles Program, July 2022
[39] California Air Resource Board, Medium- and Heavy-Duty ZEV requirement, 2020

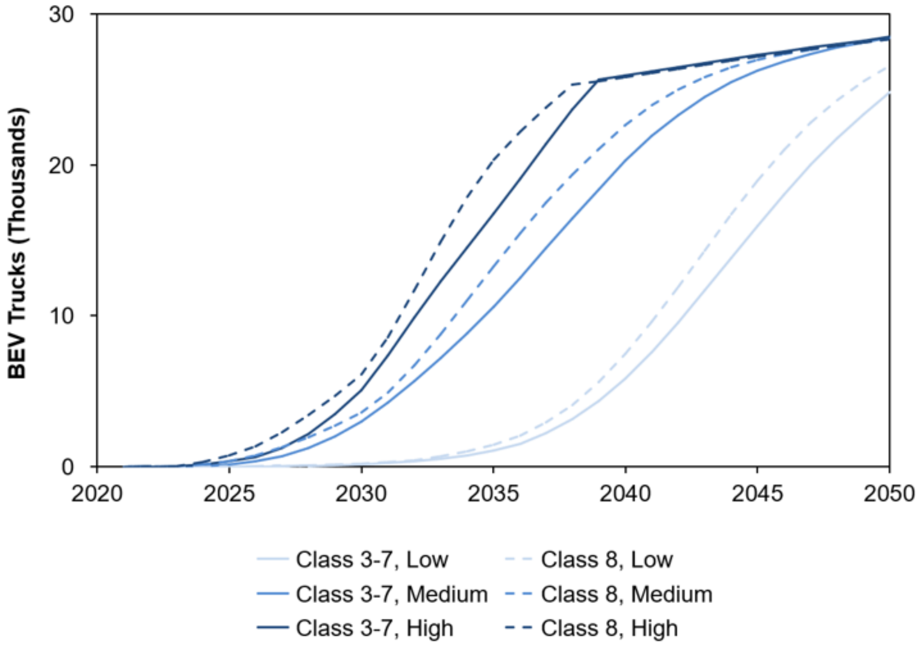


Figure 51: Stock scenarios for Class 3-7 (Medium-Duty) and Class 8 (Heavy-Duty) Trucks.

Figure 52 shows the comparative composition of the truck stock throughout the analysis for the three scenarios. The increased rate of removal of non-EVs in the High scenario is especially apparent, with 100% of medium and heavy trucks in Toronto (across all classes) switching to BEVs by 2040. In contrast, by 2050 approximately 20% of medium and heavy trucks remain non-electrified by 2050 in the low scenario.

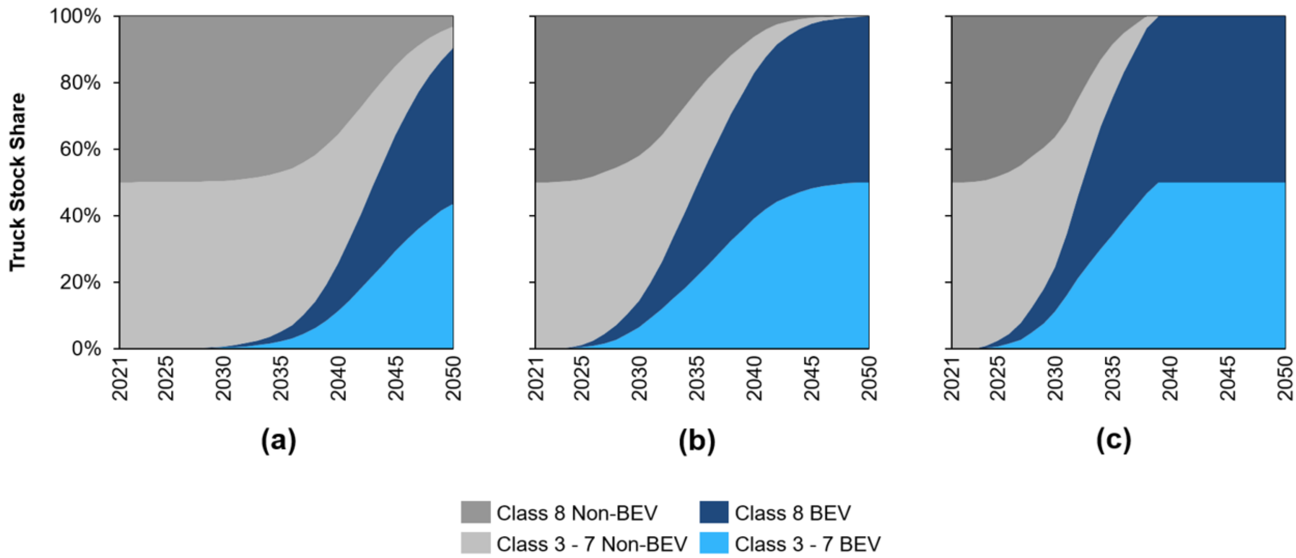


Figure 52: Truck stock split by class and powertrain in (a) Low, (b) Medium and (c) High electric truck uptake scenarios.

4.3.4 Buses

Given that the bus stock within Toronto is primarily owned and operated by a single organisation, the Toronto Transit Commission, the consumer choice approach used for other transport segments is less applicable here, so instead a simplistic representation of the TTC's decarbonization plans has been incorporated into the modelling of the bus fleet. Their current targets include the delivery of 300 BEV buses by 2025, with 100% ZEVs on the road by 2040[40]. The TTC aligned bus decarbonization phases used in this analysis can be summarized as follows:

- **Phase 1:** 20-50 BEV buses at every depot
- **Phase 2:** approximately 50% BEV rollout at every depot
- **Phase 3:** 100% BEV rollout at every depot

The date when individual depots convert their existing stock is staggered throughout each phase, and this is included in the modelling. The High scenario in this analysis aligns with the TTC's plans, while the Low and Medium scenarios include incremental delays to the completion of each phase. The assumptions applied to each scenario are set out in more detail below in Table 22. Note that in all scenarios, it is assumed that the bus stock in Toronto remains constant from the present day.

Table 22: Electric bus uptake scenario assumptions.

Decarbonization Phase	Year Phase Completed		
	Low	Medium	High (TTC compliant)
Phase 1	2029 (High + 4 years)	2027 (High + 2 years)	**2025**
Phase 2	2038 (High + 8 years)	2034 (High + 4 years)	**2030**
Phase 3	2052 (High + 15 years)	2045 (High + 8 years)	**2037**

[40] Toronto Transit Commission, TTC Green Initiatives, 2022

The number of electric buses present in Toronto under each of the above scenarios is shown below in Figure 53. The shape of the uptake curve in each scenario is similar due to the phased rollout of EVs across Toronto's buses, with the staggering between scenarios reflecting the different modelled timings for these phases.

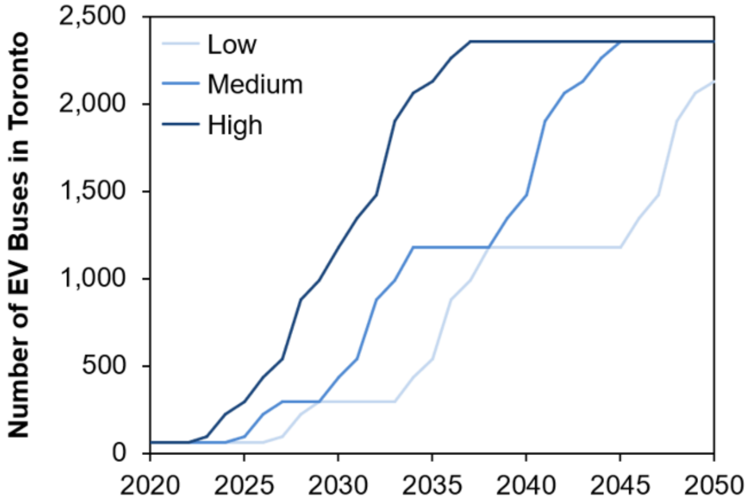


Figure 53: Electric Bus stock scenarios.

4.3.5 Rail

In Toronto, there are a number of different rail modes in operation, including:

- Subway
- Light rail
- Streetcar
- GO Transit
- Mainline Rail (VIA, Amtrak)

Of these, only the subway, light rail and streetcars are currently electrified. While there are some plans to electrify other rail modes, it is expected that these would operate on their own local network and connect to the transmission network, and so are not considered in this analysis. As of June 2022, when this analysis was undertaken, six subway and light rail expansion programs were underway or in advanced planning stages:

- Eglinton Crosstown Light Rail Transit
- Eglinton Crosstown West Extension
- Finch West Light Rail Transit
- Ontario Line
- Scarborough Subway Extension (Line 2 East extension)
- Yonge North Subway Extension (Line 1 North extension)

This also includes the closure of Line 3 Scarborough, planned for 2023. It is worth noting that after the analysis described in this report was completed, both the Waterfront Transit Network Expansion and Eglinton East Light Rail Transit projects have entered advanced planning stages. There is an opportunity for such updates to be incorporated in future iterations of this analysis. No additional significant extensions to the streetcar network are known to be planned.

To model the impacts from these extensions, a constant energy demand per km of track for each subway line has been assumed, calculated using current data on track length, energy demand and train frequency. The proposed extensions to subway lines[41] are then accounted for by multiplying the constant energy demand per km by the length of the proposed extension.

This additional demand is added to each subway line at the current grid connection and is only applied from the year of completion of expansion. This results in a single scenario, applied to all scenario worlds, with step increases in rail demand, in line with these expansions, as shown in Figure 54.

[41] The City of Toronto, Transit Expansion, June 2022

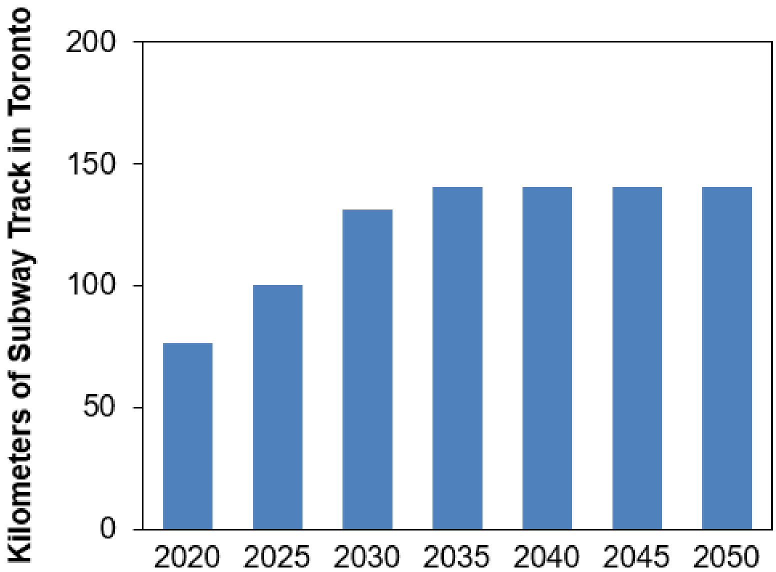


Figure 54: Total length of Subway Track in Toronto in kilometres.

4.3.6 Charging Distribution

The placement of transport demand within the modelling is challenging due to the nature of vehicles and the various ways in which they are utilized. Theoretically, any vehicle could charge at any number of points across the network as well as locations outside of the region served by Toronto Hydro. It is not enough to simply know the registered addresses of Toronto's cars; the use cases of the vehicles, the habits of their owners, and the infrastructure available for use must also be understood. The combination of these factors is referred to as "charging behaviour".

Cars and Light Trucks

The cars and light trucks represented by the Toronto-level trends presented in Section 4.3.2 are allocated to neighbourhoods as a starting point. In years preceding 2030, BEV and PHEV cars and light trucks are weighted towards neighbourhoods with greater modelled access to off-street parking, as these properties are able to install private residential charge points. This is a key driver of early EV uptake while public charging infrastructure is less mature. The distribution of homes with access to off-street charging is based on dwelling types and population density, as shown in Figure 55.

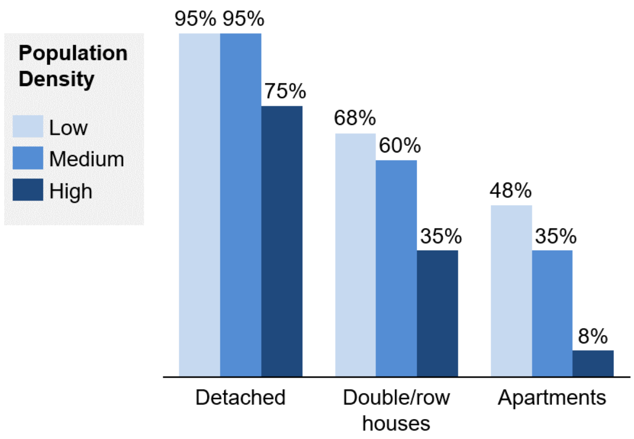


Figure 55: Level of access to off-street parking by dwelling type and population density of area[42].

After 2030, new EVs are distributed according to the current distribution of all cars across neighbourhoods, based on the assumption that access to charging will be ubiquitous across the city by that time, and a lack of private off-street charging will not impede the purchase of electrified cars and light trucks as was the case in the early years of the modelling. This then gives the distribution of EVs across the city's neighbourhoods for every modelled year. The neighbourhood an EV resides in will have a direct impact on the charging behaviour it is assumed to have in the subsequent modelling.

Cars and light trucks are assumed to charge in five distinct ways, detailed below:

- **Home charging** – owner has access to private "off-street" charging.
- **On-street residential** – owner lives in area with easy access to public charge points located by on-street parking spaces.
- **Destination** – vehicle is charged while parked at a trip destination.
- **En-route** – vehicle is charged during a journey.
- **Workplace** – owner charges their car at their workplace while at work.

Typically, most personal vehicles will be used in a variety of manners, so the customer base is further divided into eight archetypes based on the type of vehicle they own, their access to home charging and whether they commute. Within each of these eight driver types, the prominence of each of the above charging behaviours

[42] Element Energy and WSP Parsons Brinckerhoff, Plug-in electric vehicle uptake and infrastructure impacts study, 2016

varies. This breakdown is shown in Figure 56 and is derived from previous modelling work carried out by Element Energy for National Grid, which analyzed a dataset of 8.3 million charging events in the UK[43].

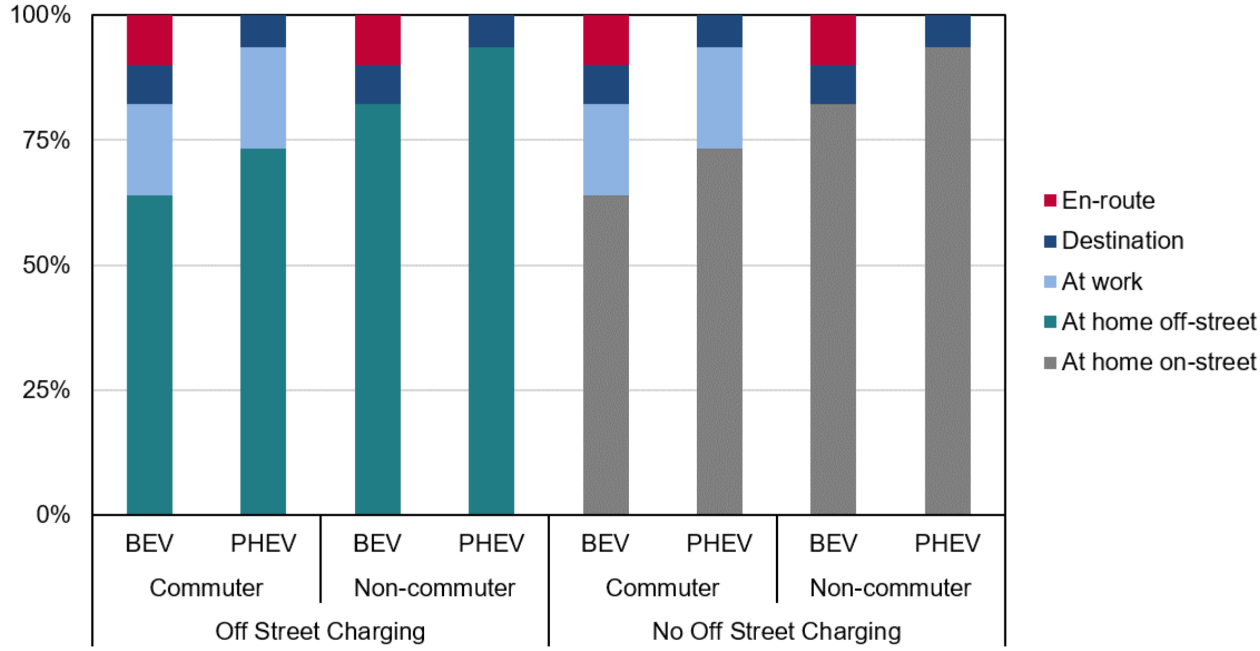


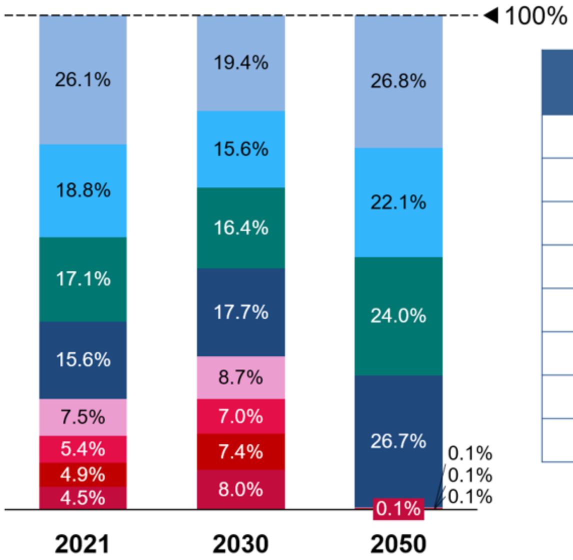
Figure 56: Prominence of charging behaviours across Toronto car and light-truck owners.

Data on the three variables defining the EV user archetypes shown in Figure 56 were used to distribute the archetypes between the neighbourhoods:

- **Powertrain proportions** (i.e. BEV / PHEV) were taken from the analysis described in Section 4.3.2. As such this parameter, and consequently the entire distribution of EV archetypes, changes between scenarios.
- **Commuting statistics** were taken from the 2021 census[44], which details the number of individuals commuting by different methods. This was combined with neighbourhood housing counts, also from the census, and data from a Toronto Metropolitan University study[45] regarding the levels of car ownership per household to give the share of cars used for commuting in each neighbourhood.
- **Home charging** was based upon access to private off-street charging and on-street public chargers, as described above (see Figure 55).

The combination of data types listed above gives a distribution of EV charging archetypes across the city which, due to the reliance on the split of BEVs and PHEVs within the vehicle stock, varies by scenario and year. Figure 57 shows the changing distribution of EV car and light truck archetypes for the Medium scenario.

[43] Element Energy, Electric Vehicle Charging Behaviour Study, 2019
[44] Statistics Canada, 2021 Census of population, 2021
[45] Toronto Metropolitan University, Household car ownership, 2018



EV Archetype	Powertrain	Off-Street Charging	Commuter
1	BEV	✓	✓
2	BEV	✓	✗
3	BEV	✗	✓
4	BEV	✗	✗
5	PHEV	✓	✓
6	PHEV	✓	✗
7	PHEV	✗	✓
8	PHEV	✗	✗

Figure 57: Changing EV charging archetype distribution at Toronto Level, Medium stock scenario

Since the EV archetype distribution varies by scenario, and because of the reliance of each archetype on different charging behaviours (as shown in Figure 56Figure 56), the physical positioning on the network of the loads due to EVs also changes between the uptake scenarios.

The location of charging events across the city (i.e. where each of the above archetypes charge their vehicles for the range of charging behaviours) was derived as follows:

- **Home charging** is consistent with the distribution of EV owners with access to off and on-street parking used to formulate the EV archetype distribution described above (Figure 58a).
- **En-route charging** is localized to existing gas stations which are within 500m of an expressway (Figure 58b). Other existing gas stations are not explicitly allocated any charging demand in the modelling. This is because the assumed prevalence of other charging types means that most drivers can charge at home or their destination for most journeys, while those on longer journeys can make use of stations near expressways.
- **Destination** and **Workplace** charging are localized to parking lots dependent on zoning data[46] (Table 23, Figure 58c, and Figure 58d).
- **Workplace** charging also considers demand from commuters who reside outside of Toronto, but commute into the city. It is assumed that en-route and destination charging events from non-Toronto residents evens out with Toronto residents who sometimes charge their cars outside of the city.

Table 23: Assumed mapping of parking lot zoning types to car and light truck charging locations.

Parking Lot Zoning Type	Destination	Workplace
Open Space	✓	✗
Commercial Residential Mixed Usage	✓	✓
Residential	✗	✗
Utility and Transportation	✓	✓
Heavy Industry	✗	✓
Employment	✗	✓
Business Park	✓	✓
Institutional	✓	✓
Commercial	✓	✓
"Other"	✓	✓

[46] City of Toronto Open Data Portal, Land use zoning by-law, 2022

Maps showing the modelled distribution of these charging locations throughout the city are shown below in Figure 58.

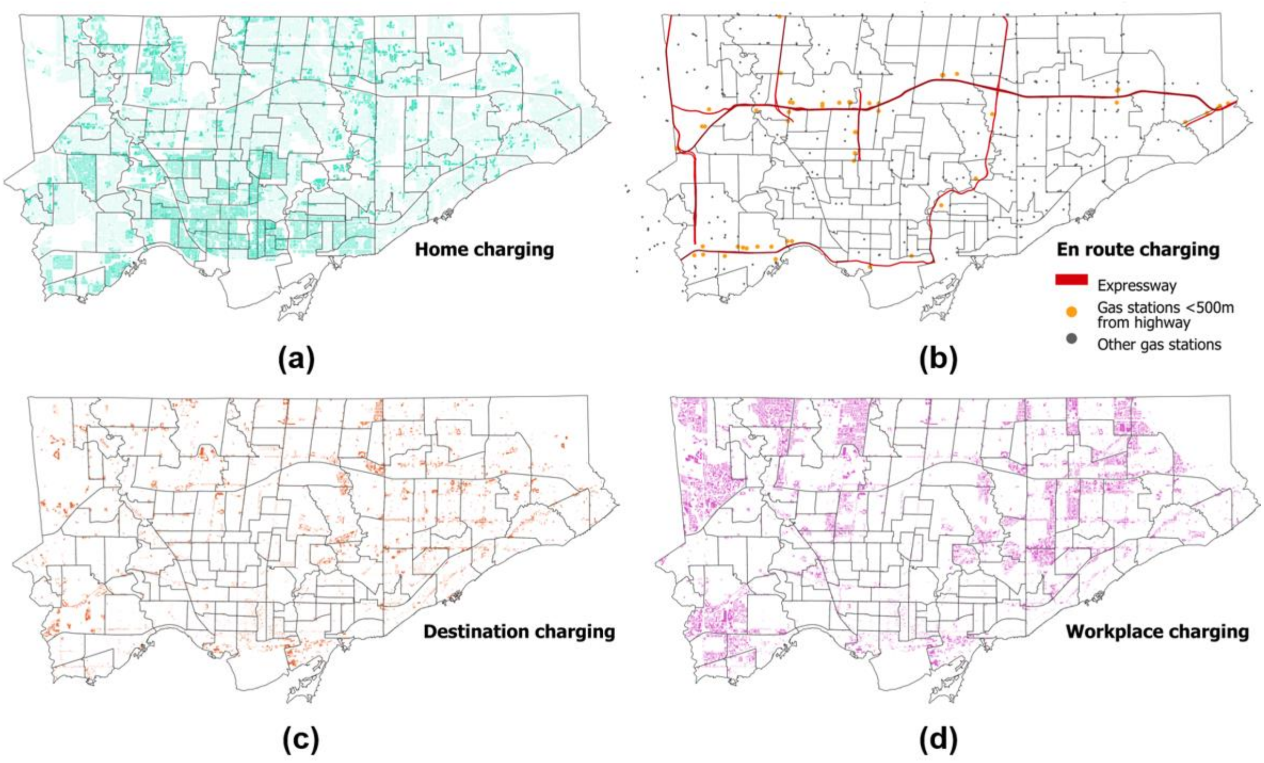


Figure 58: Charging type distributions for cars and light trucks.
(a) Home charging; (b) En-route charging; (c) Destination charging; (d) Workplace Charging.

Buses, Medium- and Heavy-Duty Trucks

As previously described in Sections 4.3.1 and 4.3.3, it is assumed that all medium- and heavy-duty trucks are used for commercial purposes only, in the same way that cars and light-trucks have been assumed to be for personal use. The modelling of medium- and heavy-duty trucks is split by weight class due to the differing energy requirements of each. In addition, different average journey lengths are assumed for each weight class to reflect the different usage patterns of medium sized trucks as compared with larger vehicles like semi-trailer trucks. Finally, all buses are treated as equal in the modelling.

As with destination and workplace charging, commercial vehicle depot charging is positioned according to parking lot zoning data[46]. The mapping used to locate charging depots for the commercial medium- and heavy-duty truck stock is shown below in Table 24. Based on research by Element Energy of truck driving behaviours across the UK[47], trucks are assumed to be able to do most of their charging at their home depot or at warehouses on their scheduled route. Longer distance trucking journeys likely require some en-route charging, however Toronto is assumed to be primarily a journey end or starting point for these trucks, so there is expected to be little en-route truck charging demand which affects Toronto Hydro's network. Therefore, all medium- and heavy-duty trucks are assumed to charge at their designated depot.

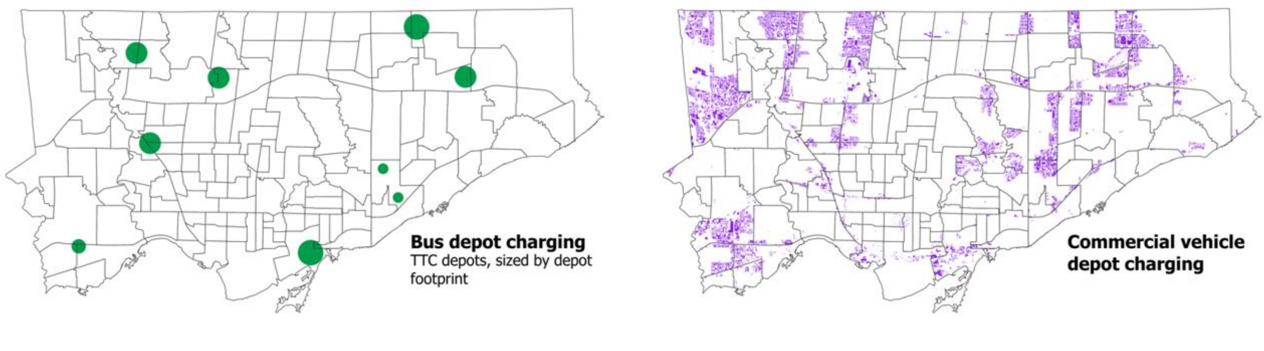
[47] Element Energy for Transport & Environment, [Battery electric HGV adoption in the UK: barriers and opportunities], November 2022

Table 24: Assumed mapping of parking lot zoning types to medium- and heavy-duty truck charging locations.

Parking Lot Zoning Type	Truck Depot
Open Space	✗
Commercial Residential Mixed Usage	✗
Residential	✗
Utility and Transportation	✓
Heavy Industry	✓
Employment	✓
Business Park	✓
Institutional	✗
Commercial	✗
"Other"	✓

The current bus depots used by the TTC are assumed in the modelling of future bus stock (see Section 4.3.4) to remain in use until 2050, with no new additions. As such, all bus charging events are assumed to occur at the locations of these depots. The buses in the stock model are also designated to a specific depot, at which they are assumed to always charge.

The distributions of the charging locations for buses, medium- and heavy-duty trucks are shown below in Figure 59.



(a) (b)

Figure 59: Charging distributions used for (a) buses and (b) medium- and heavy-duty trucks.

4.3.7 Smart Charging and Vehicle-to-Grid

With the push to electrify transport, Canadian local distribution companies (LDCs) have recently begun actively investigating the charging behaviour of EV users and the potential uptake of flexible demand-side technologies such as smart charging and "vehicle-to-grid" (V2G). However, most of these studies are ongoing and thus results are not yet available. Table 25 lists the EV charging studies explored for this work.

Table 25: Canadian LDC EV charging studies.

LDC	Description of study	Status
Toronto Hydro	EV smart charging pilot	Recruitment phase
Toronto Hydro	Utility-controlled smart charging study	Completed
Hydro One/ Peak Power	Vehicle-to-home (V2H) pilot program	Ongoing
Nova Scotia Power	Utility-controlled smart charging pilot	Ongoing
ENMAX	Smart charging study looking at demand shift potential based on incentives	Ongoing

Given the ongoing nature of these studies, there is currently limited data available on the potential of V2G technology in Canada. Subsequently, internal modelling was used to determine uptake scenarios for V2G technology. These scenarios were formulated to reflect likely levels of penetration of V2G and are conservative due to high costs of bi-directional chargers and current limitations around the business case for this technology[48].

With regards to smart charging, a few sources were used for data on the smart charging landscape within Canada and Toronto. The utility-controlled study performed by Toronto Hydro[49] had valuable baseline data on the charging behaviour of Toronto residents. Additionally, an analysis of the Plug N Drive survey in Toronto[50] identified that 83% of EV users "relied on overnight charging all of the time or some of the time". The data from these two sources, while specific to Toronto, doesn't map directly onto the smart vs. non-smart charging regimes required for this component of the analysis and were therefore used primarily as a sense check against an Ontario-level study performed by FleetCarma. The "Charge the North" study by FleetCarma[51] identified Ontario-level proportions of total charging energy by rate period. In the report, charging during the off-peak period was considered "smart"; in Ontario, off-peak charging was found to account for 85% of charging, which is close to the value reported in the Plug N Drive survey and is also close to the current ToU tariff penetration in Toronto (84%).

As the smart charging proportion matches closely with the current ToU tariff penetration, the Medium scenario envisions no change in smart charging activity, in line with the modelled ToU behaviour. The High scenario is a more ambitious view of the future, where the new overnight tariff structure proposed by the OEB, which targets EV users, is assumed to drive smart charging participation, reaching 100% in 2030. Finally, in the Low scenario, an equal but opposite rate of change of smart charging penetration as the High scenario is assumed, with participation decreasing to 70% in 2030, after which equilibrium is maintained. The scenarios developed, which outline the proportion of charging which is unmanaged, smart, or V2G, are shown in Figure 60. The Low scenario sees no adoption of V2G charging at any point, while there is a gradual introduction of V2G from 2030 onwards in the Medium scenario. In the highest ambition scenario, unmanaged charging is fully and

48 Element Energy, V2GB – Vehicle to Grid Britain Requirements for market scale-up (WP4), June 2019
49 Bauman, J. et. al., Residential Smart-Charging Pilot Program in Toronto: Results of a Utility Controlled Charging Pilot, June 2016
50 IAEE, Driver Experiences with Electric Vehicle Infrastructure in Ontario, Canada and the Implications for Future Policy Support, Fourth Quarter 2020
51 FleetCarma, Charge the North, 2019

rapidly phased out, and V2G uptake begins immediately from the base year. From 2030 onwards all EVs are charging in a flexible manner in the High scenario.

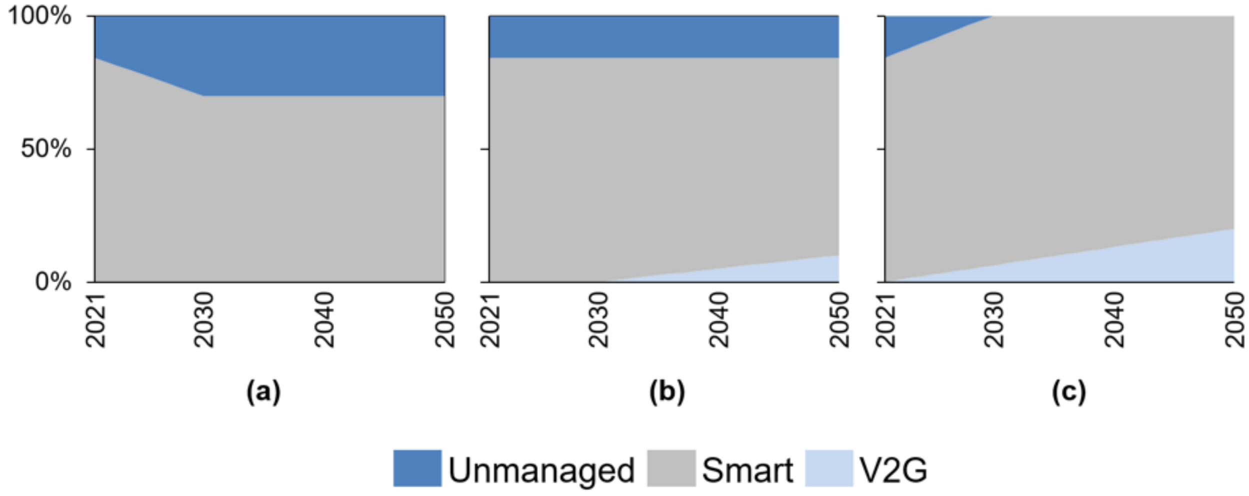


Figure 60: Proportion of EV drivers participating in various charging types, for the (a) Low, (b) Medium, and (c) High scenarios.

4.4 Electricity Generation

A range of generation technologies that can connect to the distribution network have been considered in the analysis. As with demand, three to four future uptake scenarios (e.g., Low, Medium, High, and Very High) have been developed for each technology, which have then been assigned to the four scenario worlds according to how they align with their respective narratives. The full mapping of generation uptake scenarios to the scenario worlds is shown in Table 26.

Table 26: Distributed generation technology uptake scenario mapping.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Rooftop solar PV*	Low	Medium	High	Low	Very High	Low
Ground-mount solar PV*	Low	Medium	High	Low	High	Low
Wind	Low	Low	High	Low	High	Low
Biogas	Low	Medium	High	Low	High	Low
Non-renewables	High	Low	Medium	High	Low	High

* Rooftop solar PV is defined as installations of capacity less than or equal to 250 kW and ground-mount solar PV refers to installations larger than 250 kW.

4.4.1 Modelling Approach

The approach used for modelling the uptake of distributed generation consists of three steps, as outlined in Figure 61. Existing generation is used as a baseline value and a pipeline is added to this value over a pre-defined number of years. After this point, uptake projections follow the long-term pathways that are generated based upon a range of methods, including consumer choice modelling, external datasets, and stakeholder engagement.

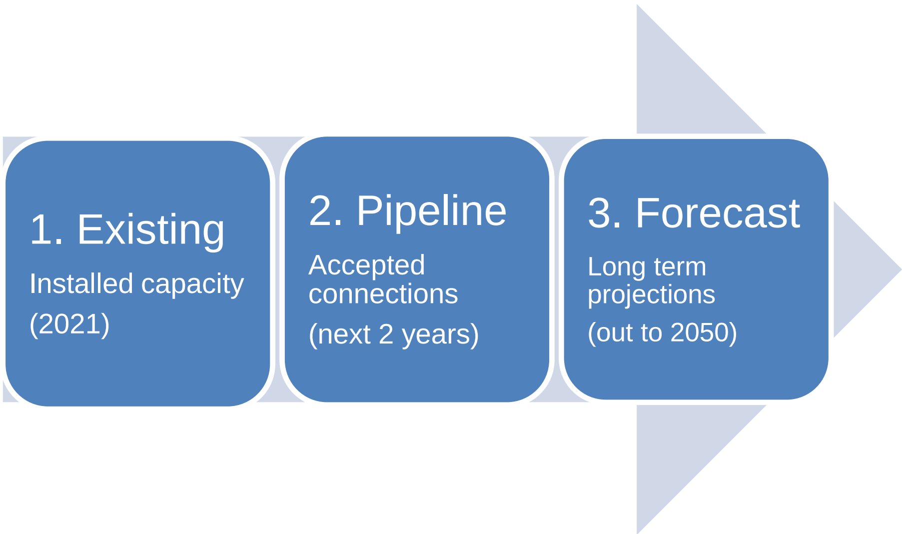


Figure 61: Pathway for modelling distributed generation.

Existing generation capacity was drawn from data provided by Toronto Hydro, which was checked against other sources such as the IESO Active Contracted Generation List[52]. The existing generation baseline included everything connected by the end of 2021.

[52] IESO, Active Generation Contract List, June 2021

The pipeline for all generation and storage was defined as the two years after the baseline, that is 2022 and 2023. The proportion of pipeline connections projected to connect varied by scenario and by size, as detailed in Table 27. These definitions reflect Toronto Hydro's understanding of how pipeline generation typically connects, based upon historic trends.

Table 27: Proportions of pipeline generation capacity that connects in each scenario.

Pipeline Generator Size	Low	Medium	High
< 1MW	40%	60%	100%
≥ 1MW	60%	90%	100%

The method used for developing long-term projections varied by generation technology and is summarized in Table 28. Solar PV uptake projections were developed using Element Energy's in-house consumer choice model, whilst wind projections were developed through consultation with Toronto Hydro stakeholders. Non-renewables uptake projections were based upon projections from the TransformTO dataset, and biogas projections were based upon varying levels of fuel switching as non-renewables are phased out. Note that there was no pipeline generation for wind or biogas. Existing and pipeline generation is distributed to transformer station buses according to the current or expected locations of deployment, while projected generation is distributed across the region according to various methodologies which are specific to each technology.

Table 28: Modelling method for distributed generation technologies.

Technology	Renewable	Pipeline duration	Long-term projection
Solar PV	✓	2 years	Element Energy in-house modelling and TransformTO proejctions
Wind	✓	No pipeline	Informed by consultation with Toronto Hydro Stakeholders
Biogas	✓	No pipeline	Informed by TransformTO non-renewables projections
Non-renewables	✗	2 years	Data drawn from TransformTO

The total level of generation in Toronto Hydro's network area is show in Figure 62, illustrating capacity across all four scenario worlds in 2021, 2030, and 2050. This figure demonstrates that, based upon the modelling, solar PV is likely to be the dominant distributed generation technology in Toronto Hydro's region in a decarbonized future. This is particularly pronounced in the Net Zero 2040 scenario world, where projections have been aligned with the Net Zero 2040 projections in TransformTO. All three net zero compliant scenario worlds phase out non-renewable generation technologies by 2050 and rely strongly on solar generation, whereas Steady Progression continues to rely on electricity from gas and diesel out to 2050. In the following sections, these results are discussed in more detail. Section 4.4.2 explores the modelling of solar PV, the largest single contributing factor to the generation mix in 2050 for all four scenario worlds.

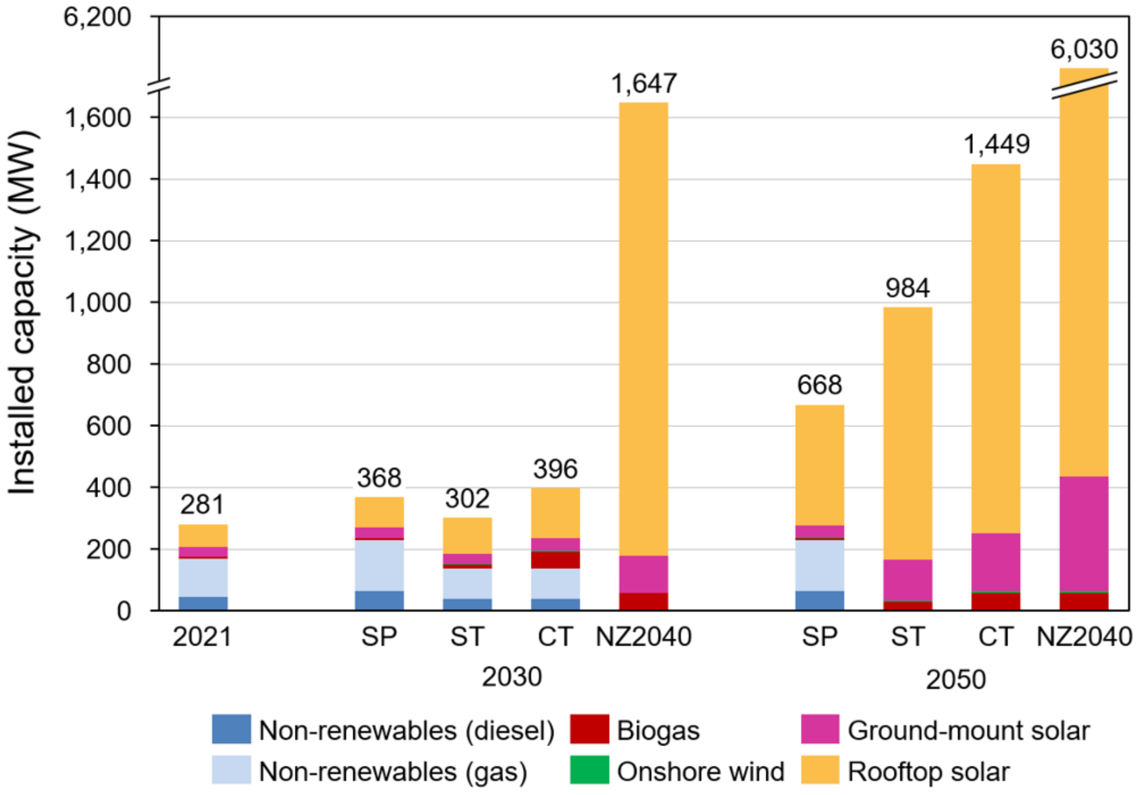


Figure 62: Capacity of distributed generation installed in Toronto Hydro's network area in 2021, 2030 and 2050.

4.4.2 Solar Photovoltaics

Solar PV uptake scenarios were derived using a consumer choice model for rooftop (≤250 kW) and large-scale (>250 kW) generation uptake. This uptake model accounts for variation in solar PV installation properties and economics by modelling different size bands. The size bands have been associated with typical installation types, as summarized in Table 29 below, and different installation costs applied to each band.

Table 29: Classification of solar PV size bands.

Solar PV Size Bracket (kW)	Classification
≤ 250	Rooftop
> 250	Ground-mounted

Rooftop Solar PV (≤ 250kW)

Small-scale solar PV is defined as being those installations that occur on rooftops of domestic and I&C buildings (Table 29Table 29). Figure 63 shows that the solar uptake in the Low, Medium and High scenarios, which are developed using Element Energy's consumer choice model, range between 400 MW and 1,200MW by 2050. These increase from a baseline of 75 MW in 2021 and a maximum pipeline of 3.4 MW. These pathways are developed by considering the economic case for purchasing solar panels from a consumer perspective. Post-pipeline uptake to 2050 is driven in large part by capital cost reductions[1,53], while increases in electricity prices[54] and net metering revenues[55] further incentivize uptake in future years. Rooftop solar is distributed across Toronto using customer counts in each neighbourhood and terminal station service area.

Future solar generation is calibrated using historic uptake data[52] and by considering the business case of purchasing solar panels in previous years[56]. Using this information, the model develops calibration coefficients that are used to adjust future solar generation projections.

In the Low scenario, it is assumed that the energy system will continue to rely on gas- and diesel-fired generation in 2050 and less emphasis is placed on incentives for the uptake of renewable generation. Conversely, in the High scenario, uptake is based upon the lowest projections of capital installation costs, higher revenues from net metering and avoidance of electricity charges. In the Very High scenario, projections are aligned with those from TransformTO[3], adjusted to the baseline and pipeline data provided by Toronto Hydro, resulting in an uptake of 5,600MW of rooftop solar generation installed by 2050. The Very High scenario is based on the technical potential of solar generation in Toronto and hence represents an upper bound where 100% of suitable buildings install solar PV.

[53] NREL, Solar Futures Study, 2021
[54] Higher electricity prices can result in higher uptake since consumers that install a solar PV system can avoid paying these high prices for their electricity to some extent and can also potentially achieve higher revenues when selling their generation back to the grid.
[55] OEB, Electricity Rates, 2022
[56] IESO, microFiT Program, 2022

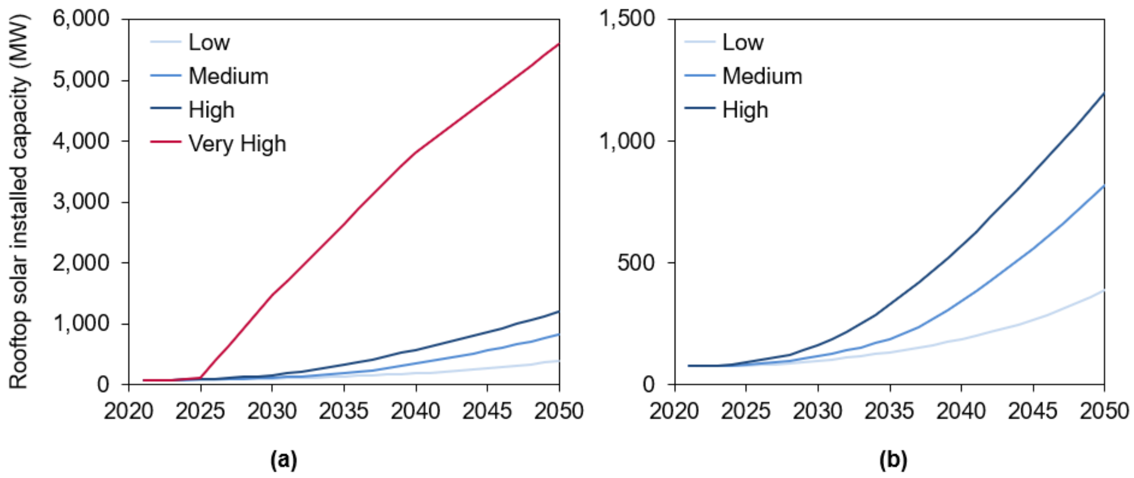


Figure 63: Installed capacity of rooftop solar PV in Toronto Hydro's network area out to 2050. (a) including "Very High" scenario, used in NZ40; (b) excluding "Very High" Scenario.

Ground-Mount Solar PV (>250kW)

Ground-mount solar PV is defined as those installations that have a capacity greater than 250kW and are likely to be deployed in parking lots or green space. Figure 64 shows that uptake in 2050 ranges between 39 MW and 371 MW across the Low to Very High scenarios. The overall approach is the same as that taken for Rooftop solar PV with the Low to High scenarios generated using Element Energy's consumer choice model and the Very High scenario aligned with the pathway in TransformTO. Ground-mount solar PV relies on the same drivers as for small solar PV but also draws some benefits from capacity market revenues[57]. A cost uplift has also been applied to account for additional costs associated with finding suitable areas to site generation. Where rooftop solar PV is distributed according to customer counts, ground-mount solar PV is distributed to available space in parking lots[58], in line with Transform TO assumptions on ground mounted PV deployment.

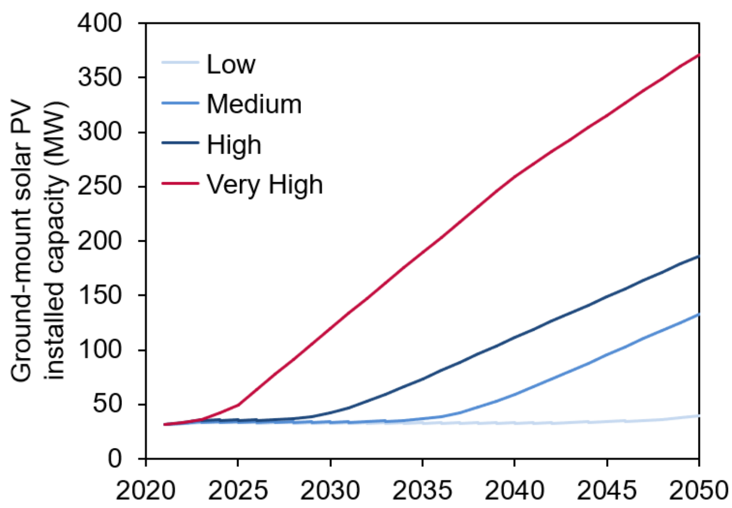


Figure 64: Installed capacity of ground-mount solar PV in Toronto Hydro's network area out to 2050.

[57] IESO Capacity Auction, 2022
[58] City of Toronto, Physical area of parking lots, 2019

4.4.3 Onshore Wind

Onshore wind projections were developed through consultation with key stakeholders within Toronto Hydro to establish a consensus on the expected range of uptake that could occur across the different scenario worlds. Due to there being very few historic onshore wind installations in Toronto (only four installations, the largest of which took place when no feed-in tariffs were in place), a meaningful calibration of the consumer choice modelling for onshore wind could not be conducted. The consultation process with Toronto Hydro stakeholders resulted in scenarios ranging between 0.76 MW and 8.3 MW of installed capacity by 2050. Projections are assumed to ramp up linearly after the pipeline years; however, the accepted generation data provided by Toronto Hydro does not include any onshore wind and so there is no projected pipeline capacity. Future uptake of onshore wind was distributed based upon greenspace in neighbourhoods adjacent to Lake Ontario which involved spreading uptake across this area rather than attempting to model individual turbine locations.

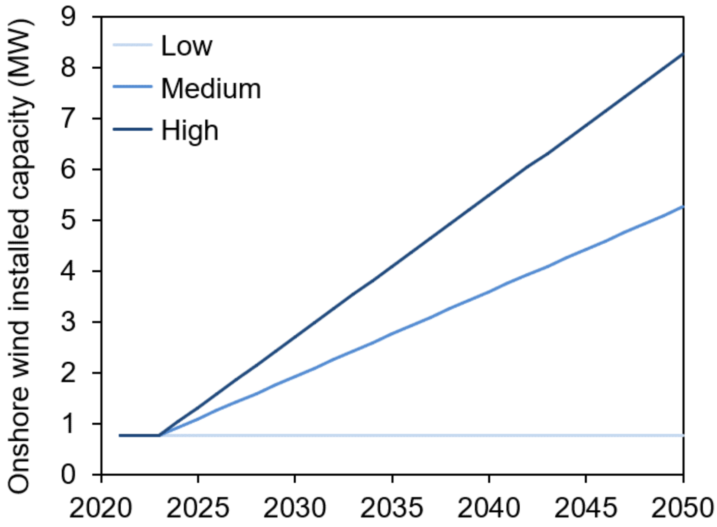


Figure 65: Installed capacity of onshore wind in Toronto Hydro's network area out to 2050.

4.4.4 Non-Renewables

Non-renewable generation considers all gas and diesel generators in Toronto, which currently make up the largest share of distributed generation. In the Low scenario, it is assumed that all non-renewable generation is phased out by 2030. This is consistent with the trajectories mapped out in TransformTO and is in line with ambitions of various municipalities in Ontario, including the City of Toronto[59]. The TransformTO trajectory for natural gas has been applied to all non-renewable generation, as TransformTO does not have specific categories for local CHP or diesel generation. This trajectory was scaled such that it aligns with existing generation connected to the Toronto Hydro network. In the Medium scenario, this trajectory is extended to 2050, assuming that the phase out follows the same pathway but at a slower rate. In the High scenario it is assumed that after pipeline generation is added, there is no phase-out of non-renewable generation and no new installations are added.

[59] Ontario Clean Air Alliance, Ontario Municipalities that have endorsed gas power phase-out, March 2021

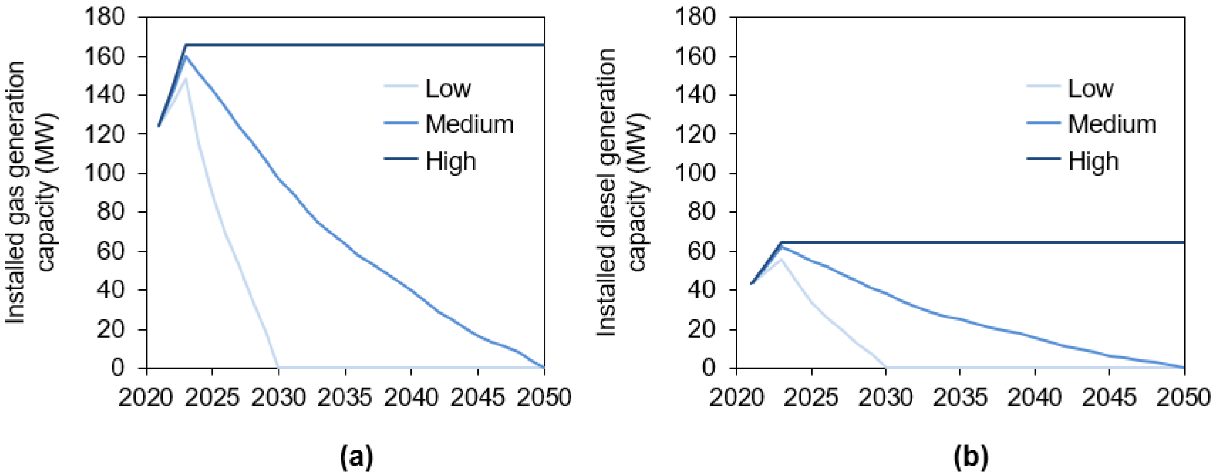


Figure 66: Projected installed capacity of (a) natural gas generation and (b) diesel generation.

4.4.5 Biogas

Biogas is assumed to act as a transition technology for natural gas and can be used in a variety of applications, including electricity generation. The High scenario for biogas pairs with the Low non-renewable scenario and is created by assuming 25% of phased-out non-renewable generation capacity is replaced by biogas. The Medium biogas scenario pairs with the Medium non-renewable scenario and assumes 10% of phased-out non-renewable generation is replaced by biogas. The Low scenario is a continuation of historic trends. In all biogas scenarios, there is no additional capacity in the pipeline. Since biogas is assumed to replace non-renewables, geo-distribution for biogas generation is based upon the historic distribution of gas generation.

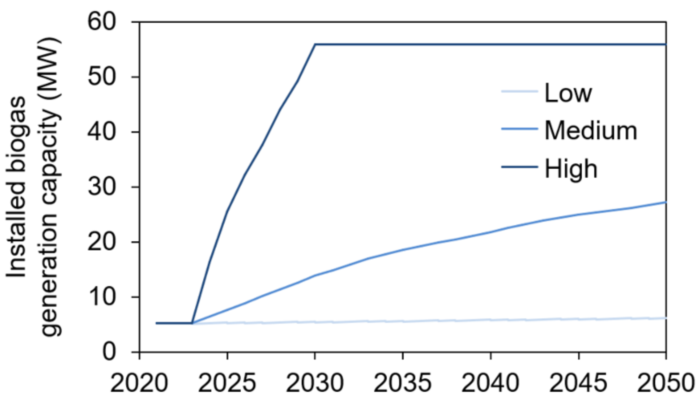


Figure 67: Installed capacity of biogas for electricity generation in Toronto Hydro's network area out to 2050.

4.5 Energy Storage

The uptake of two different battery storage use cases was modelled in this project. For each use case, three to four future uptake scenarios were developed and assigned them to the four scenario worlds as outlined in Table 30.

Table 30: Battery storage types modelled and their mapping to scenario worlds.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Domestic battery storage	Low	Medium	High	Low	Very High	Low
I&C behind-the-meter battery storage	Low	Medium	High	Low	High	Low

Grid-scale storage is assumed to be driven by network-level needs for energy storage and is therefore not modelled within the Future Energy Scenarios. This approach considers grid-scale storage to be a solution which would be deployed in response to needs identified by Toronto Hydro. Storage could also be developed by the IESO in response to overall system needs. However, it is likely that this would not be connected to Toronto Hydro's network, but rather in other areas in Ontario where land is cheaper and/or connected to the transmission network.

The uptake of battery storage for each use case is modelled based on a specific set of assumptions around the associated business case for those particular battery storage installations. Table 31 shows the different use cases, the relevant business case considered, and the modelling method used.

Table 31: Modelled battery storage use cases and the corresponding business cases and modelling methods.

Technology use case	Modelled business case	Modelling method
Domestic battery storage	**Coupled to solar PV** Maximize own use	Consumer choice modelling coupled with domestic solar PV uptake modelling
I&C behind-the-meter battery storage	**Arbitrage and system balancing** e.g., electricity price arbitrage, the Industrial Conservation Initiative (ICI), Operating reserve	Consumer choice modelling

The baseline and pipeline data for behind-the-meter storage, both domestic and industrial and commercial, was from the data provided by Toronto Hydro. The pipeline calculations follow the same methodology across the scenarios as used for generation (Table 27Table 27). Figure 68 shows the overall level of battery storage capacity installed across Toronto Hydro's region in all four scenario worlds in 2030 and 2050. Consumer Transformation and Net Zero 2040 show the highest battery storage uptake since these scenario worlds are assumed to have the greatest need for storage to help offset grid demands caused by high electrification and rapid uptake of low carbon technologies. In these scenarios, battery prices are assumed to follow their lowest cost trajectory, and higher revenue streams for both domestic and I&C behind-the-meter storage are assumed. For domestic storage, this corresponds to higher income from grid-export and higher savings from self-consumption, while I&C storage draws from a larger revenue stack which includes the Industrial Conservation Initiative (ICI), price arbitrage, and operating reserve. System Transformation sees less battery storage uptake due to lower assumed levels of electrification. Steady Progression sees the least uptake as the scenario world with the lowest levels of ambition and decarbonization. In the following sections, the modelling approaches and assumptions for battery storage are outlined and the results are discussed in more detail.

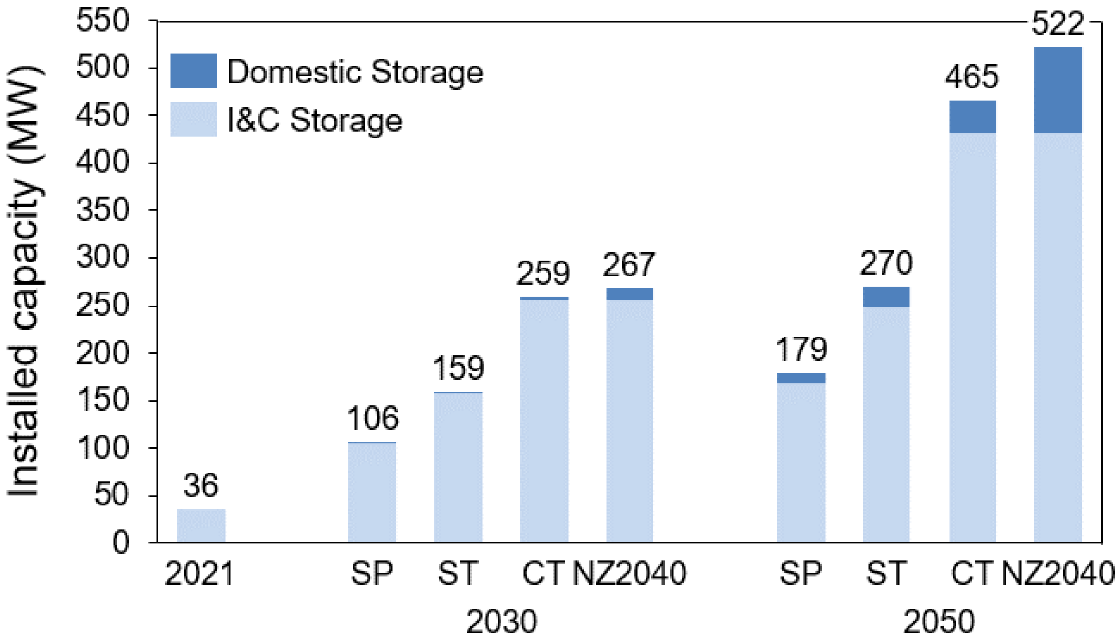


Figure 68: Capacity of battery storage installed in Toronto Hydro's network area in 2021, 2030 and 2050.

4.5.1 Domestic Battery Storage

The business case for domestic storage is coupled to the uptake of solar generation that is expected to connect at domestic residences (≤10 kW). Uptake scenarios for domestic storage are derived using a module of the solar generation consumer choice model. This considers the purchase decision for a solar PV system with a battery as well as retrofitting a battery to an existing solar PV installation which is less than five years old. Therefore, scenarios for domestic battery storage differ according to the underlying scenario for solar PV (since the batteries are added to households with solar PV) and by the battery cost projection used in each case. An average battery power is considered to be half the solar panel capacity, with a two-hour storage capacity, and account for variances in battery pack costs[60,61], installation costs, and product availability across the three scenarios. If the battery option is chosen, the owner is assumed to use it primarily to maximize their own consumption of their solar PV generated electricity.

The results from this modelling (Figure 69Figure 69) indicate that between 23% and 34% of all domestic solar PV owners in Toronto Hydro's network area may install a battery by 2050. While the proportion of solar PV owners with batteries is assumed to be the same in the High and Very High scenarios, the absolute capacity is much greater in the Very High scenario due to the substantially larger level of solar generation uptake. Therefore, the range of uptake in the Low to High scenarios is between 11MW and 34MW, while the Very High scenario sees an uptake of 90MW. Baseline and pipeline capacity for domestic battery storage are both assumed to be zero.

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[60] NREL, Cost Projections for Utility-Scale Battery Storage: 2021 Update, June 2021
[61] KPMG, Development of decentralized energy and storage systems in the UK, October 2016

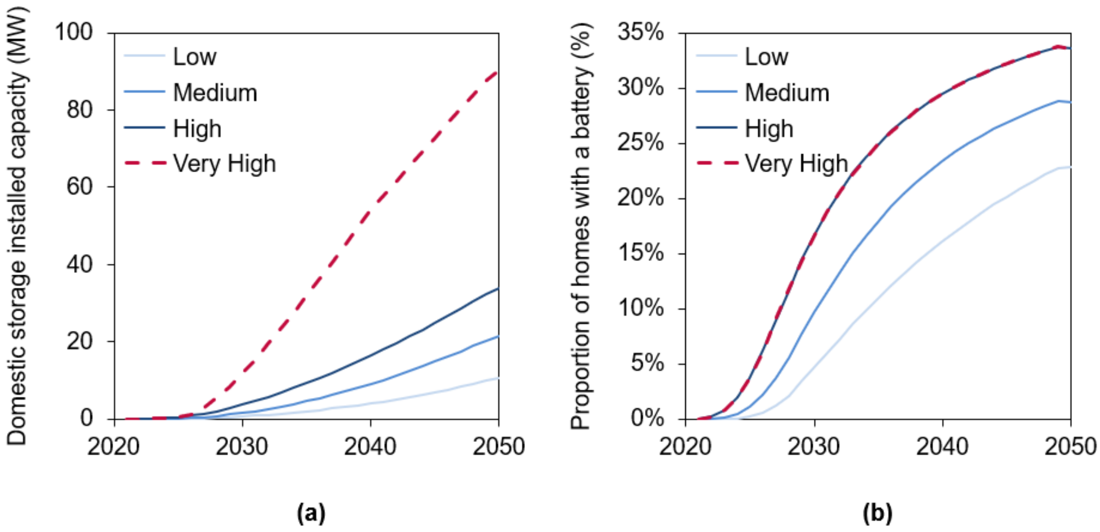

Figure 69: (a) installed capacity of domestic storage in Toronto Hydro's network area out to 2050, (b) proportion of all domestic customers who install a battery.

4.5.2 Industrial and Commercial Battery Storage

Uptake scenarios for I&C behind-the-meter storage were derived using Element Energy's consumer choice model, where I&C customers are divided into archetypes, based on different business types, and uptake is based on the payback period for investing in a battery and the willingness-to-pay of I&C organisations. Revenues from different sources are combined to find the maximum level of benefit that a storage owner could aggregate. These include wholesale price arbitrage[62], the Industrial Conservation Initiative (ICI)[63], operating reserve[64], regulation service, the capacity market[57], and the energy efficiency auction pilot. Of these, the ICI is the dominant revenue stream with a significant impact on uptake in each scenario[65]. In the Low and Medium scenario, these revenues are only accessible for customers with peak demand > 1MW. In the High scenario, these revenues are also accessible to manufacturing and warehouse archetypes with a lower peak demand. With most revenue streams only being available to customers with peak demand greater than 1MW, the modelling shows a significantly higher uptake of storage for customers connected to the high voltage network compared those connected to the low voltage network.

Figure 70 shows how these assumptions result in trajectories that reach between 129 - 381 MW in 2050. Pathways increase from a baseline of 11.8MW, with a pipeline ranging between 12.8MW in the Low scenario and 23.5MW in the High scenario.

[62] IESO, Hourly Ontario Energy Price, 2022
[63] IESO, Industrial Conservation Initiative Backgrounder, July 2022
[64] IESO, Ancillary Services, 2022
[65] Participants in the ICI pay global adjustment charges based upon their level of contribution to the top five hours of demand throughout the year. ICI revenues are calculated as the global adjustment charge that could be avoided by demand shifting with energy storage.

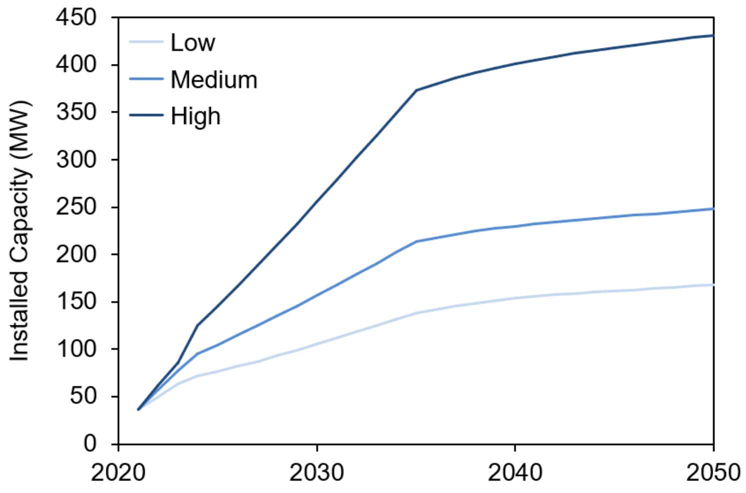

Figure 70: Installed capacity of I&C behind-the-meter battery storage in Toronto Hydro's network area out to 2050.

5 Network Impacts

Following the creation of the Future Energy Scenarios for Toronto Hydro, these datasets were loaded into Element Energy's FES Model to project the load growth and generation on the network out to 2050. This model projects the annual consumption and peak electricity demand for each of the 88 assets on the network as well as for the network as a whole, in order to provide a complete picture of the potential future changes to the network. In addition to the peak demand breakdown by asset, the peak by technology is also provided to facilitate a complete understanding of load growth and help the end user to plan and target network investments. Element Energy's load modelling systems are currently active across various electricity distribution companies and have a strong track-record of active use within the industry under the scrutiny and approval of the relevant regulators and associated reporting. As such, the FES Model is fully equipped with the latest innovations in this area.

5.1 Load Modelling Process

The load modelling process used by the FES Model can be divided into four main calculation stages (Figure 71Figure 71): technology counts, annual consumption and generation, profile shapes and peak demand, and scaling calibration. Technology counts define the raw numbers of each technology (or capacity figures in the case of generation and storage) and how they are distributed across the network. This information is then leveraged along with data regarding the characteristics of each technology in order to calculate annual consumption or generation (MWh) values. Peak demand (MW) is subsequently established through the application of load profiles, which describe how the energy consumption of each technology is distributed across the year. Finally, the scaling calibrates modelled results by aligning them with real network load data provided by the electricity distributer.

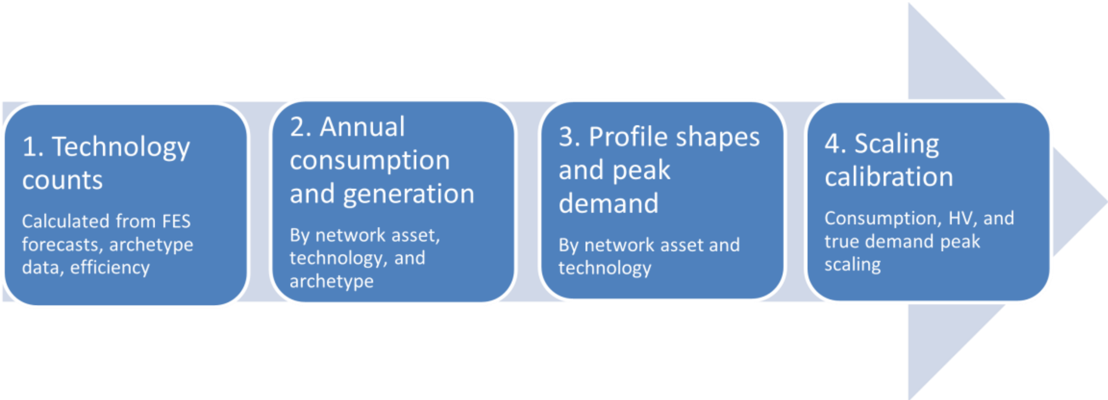

Figure 71: The main stages of the load modelling process.

Technology Counts

The first step of the process is to find the number of each technology (referred to as counts) in each year by transformer station bus and archetype. This typically begins with feeding in data from the FES, namely the geo-distributed technology projections and number of customers served by each transformer station bus (customer counts). These counts are then mapped to specific assets by leveraging the network topology which describes the connectivity between assets across Toronto.

Annual Consumption and Generation

The annual consumption and generation step involves finding how much energy is consumed or generated by a given technology in each year. Typically, this will leverage the counts as well as any information regarding the characteristics of each technology and customer type. This behavioural data varies by sector and may include such datasets as electric vehicle mileage, heating technology efficiencies and generation capacity factors.

The following steps are focused on demand, however a similar process is used for generation calculations.

Profile Shapes and Peak Demand

Following calculation of consumption values, the next stage in the load modelling process is the calculation of peak demand (MW), which is achieved primarily through the application of load profiles. Load profiles describe how the annual consumption from each technology and archetype is distributed across the year, defined for each month at a half-hourly resolution, as shown in Figure 72 for domestic core demand. These profiles are distinct for every key driver of load and there also exist options to use a minimum or average profile depending on the desired model outputs.

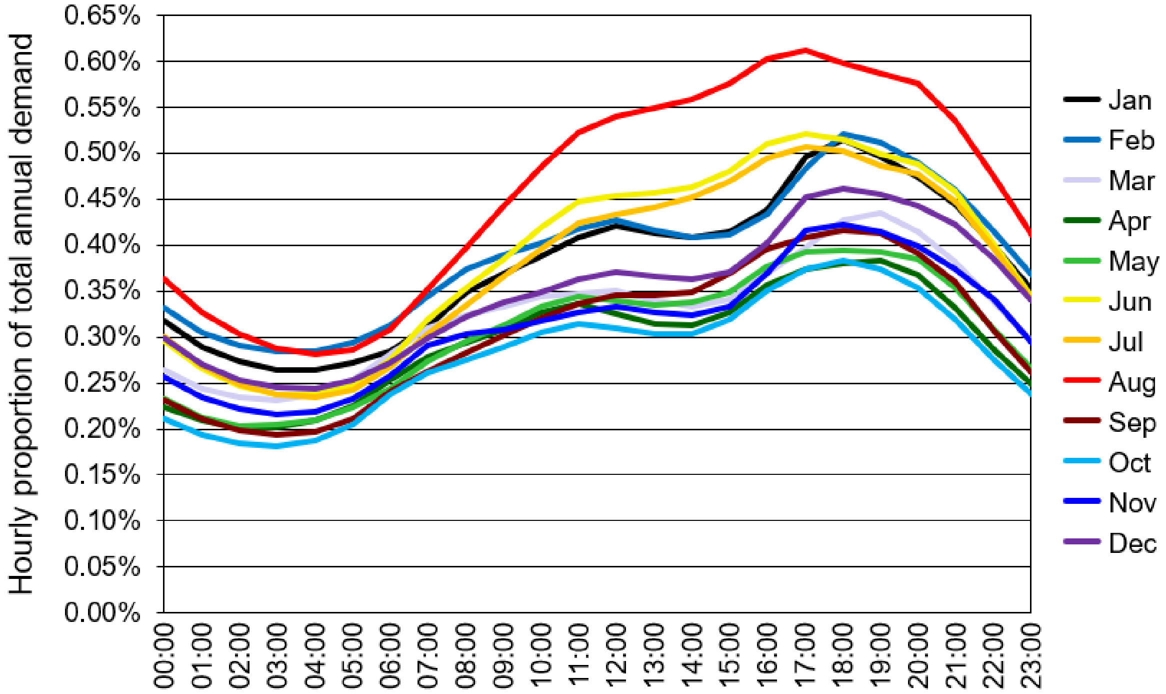

Figure 72: Load profiles for domestic core demand.

Applying load profiles to annual consumption shows how power demand for each technology varies across every modelled year. These power demands can then be summed across all relevant technologies to find the overall demand at every transformer station bus at any given time of day across the year. From this, the peak demand can be found by extracting the maximum power value from any given year. A similar process is performed to find system peak, whereby the power demand from each asset is aggregated and the maximum value is again extracted.

Scaling

Following calculation of annual consumption and peak demands, the results are calibrated by aligning values with real data from network assets. This dataset was provided by Toronto Hydro and processed by Element Energy in three scaling stages: consumption scaling, high voltage (HV) customer scaling and true demand peak scaling. The scaling steps begin with coarse adjustments at system level and finish with calibration of every technology at every transformer station bus, to make sure that the modelled load is fully aligned with real measured data from Toronto Hydro.

The consumption scaling calibrates the FES model by calculating a system-wide consumption estimate based upon Toronto Hydro consumption data aggregated from all customers connected to the network. This estimate is then compared with the base year modelled system consumption values from the FES model and appropriate scaling is applied. The HV scaling process then calibrates the model outputs by making scaling adjustments to the high voltage customer loads. The final calibration step, true demand peak scaling, focuses in on each technology at each transformer station bus for which appropriate monitoring data is available, to ensure results are as accurate as possible. This is a more granular process than consumption scaling since true demand peak scaling applies unique scaling factors at each transformer station bus to ensure alignment both in total system load and individual asset loads.

5.1.1 Load Modelling Case Study: Low Carbon Heating

The type of data inputs that are used and the way in which they are processed is specific to the technology that is being modelled and therefore, the focus here is on the modelling process for the heating sector as one example (Figure 73Figure 73). In this case, the FES inputs include technology projections, building archetype definitions/distributions[66], new build growth, building demolition rates, and thermal efficiency trends. This case-study focuses specifically on the first two steps of the load modelling process since the peak demand calculation and scaling stages are generic and applied in the same way for all sectors.

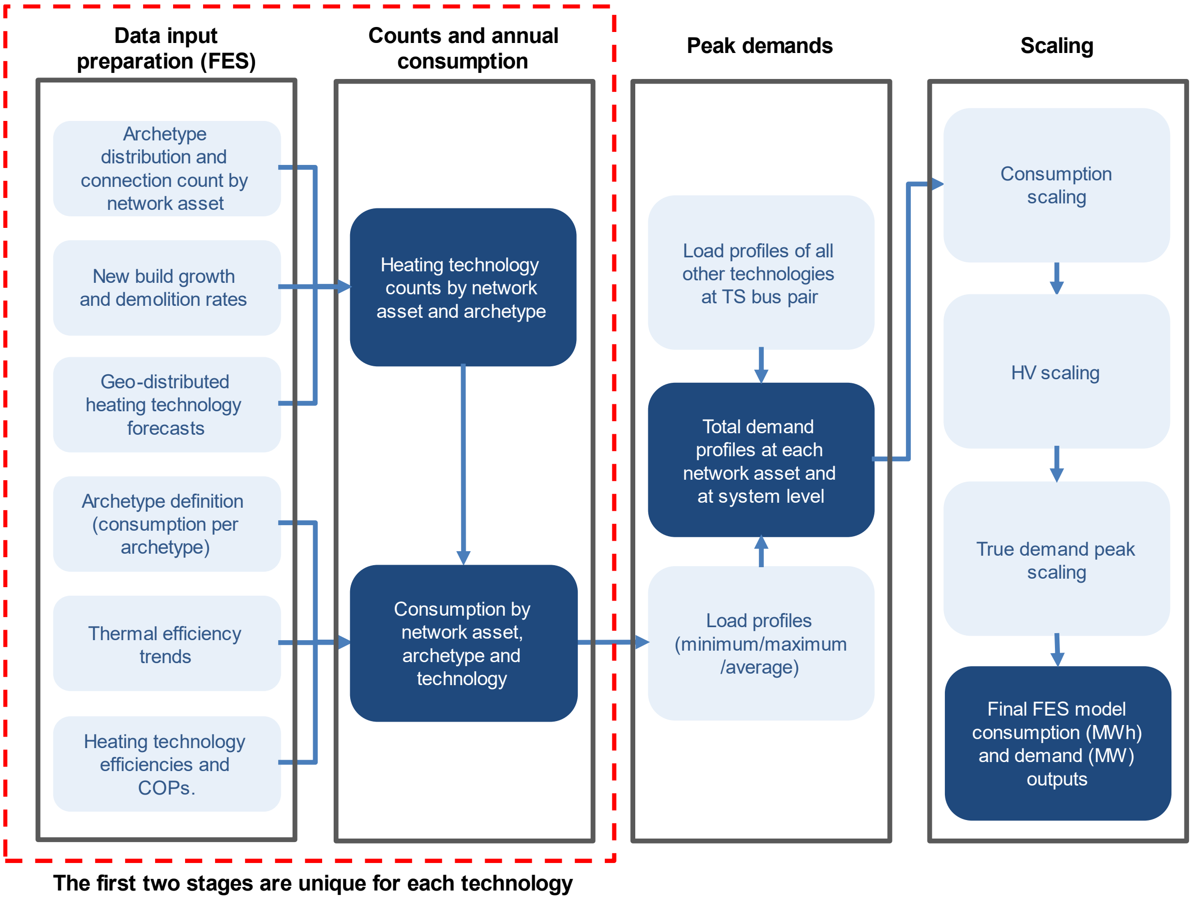

Figure 73: Detailed diagram of the load modelling process.

Technology Counts

For the heating sector, technology counts are found by first combining the archetype distribution, connection counts, new build growth, and building demolition rates to determine the number of customers of each archetype at each transformer station bus. Heating technology numbers are then established by applying the archetype specific heating technology uptake trends from the FES to find the number of each heating technology by archetype at each transformer station bus, for each year in the analysis horizon.

Annual Consumption

Once the heating technology counts are established, the annual consumption may be calculated by feeding in information about the typical characteristics of each heating technology and each building archetype. This

[66] Element Energy's FES modelling involves the definition of a set of archetypes that describe the different types of building that occur within Toronto. See section 4.1.1 for further details. The archetype distribution defines the proportion of each archetype at each transformer station bus.

includes heating technology efficiencies[67], thermal efficiency trends, and archetype definitions, which contain information about the average annual consumption for each consumer archetype.

Peak demands and Scaling

Following the annual consumption step, most technologies follow a similar methodology for the peak demand and scaling calibration. As detailed in Section 5.1, peak demands are found through the application of load profiles, which is followed by the three scaling stages (consumption, HV, and true demand peak).

5.2 Network Level Results

The final results of the load modelling process are summarized in Figure 74, which illustrates how the projected winter and summer system peak loads vary between different scenario worlds across all modelled years. Throughout the 2020s, summer peak is greater than winter peak and there is little variation across the scenarios, however, by 2050 the scenario worlds diverge considerably; Net Zero 2040 has the lowest system load, followed by Consumer Transformation, Steady Progression and System Transformation.

Figure 74 also shows the two low-efficiency scenarios, which are based upon Consumer Transformation and Net Zero 2040. More detail on the scenarios is given in section 2. The purpose of these sensitivity scenarios is to illustrate what the maximum system peak could be, caused by high levels of electrification without any measures to counter the added demand. These sensitivities represent the highest-load scenarios and would therefore lead to the highest levels of grid constraints and reinforcement costs.

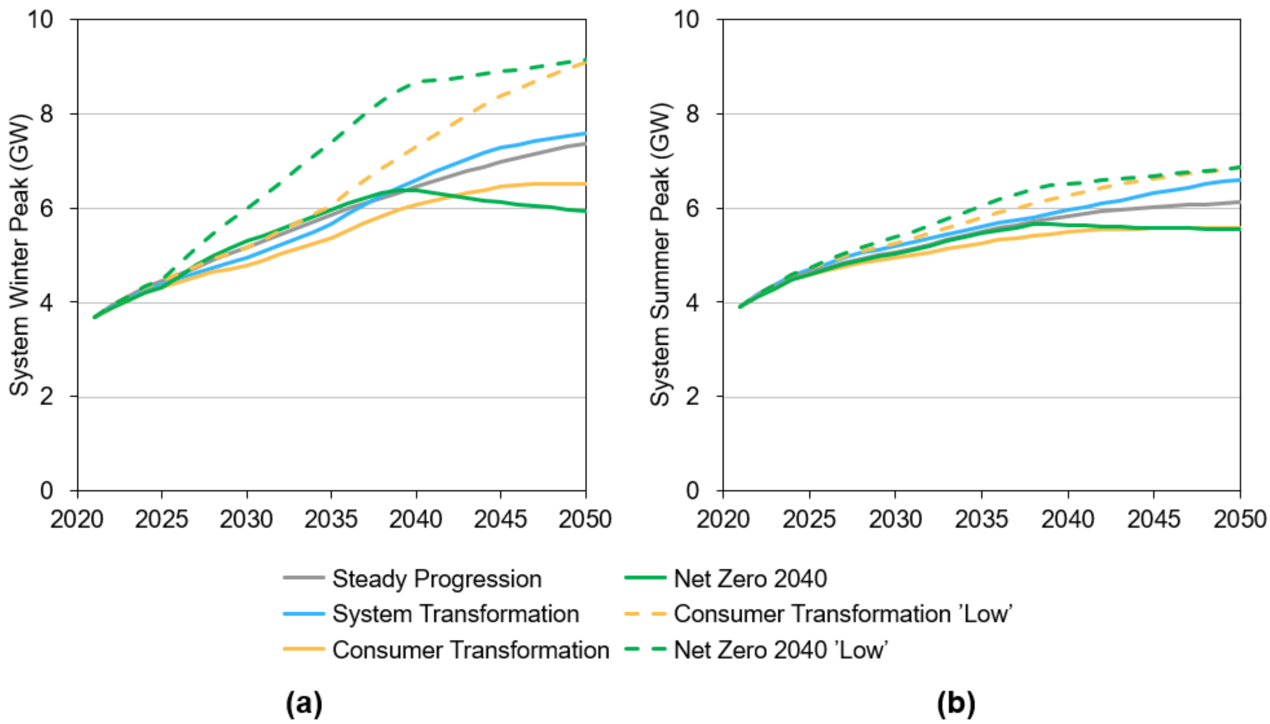

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Figure 74: Network peak in (a) winter and (b) summer for the four main scenario worlds and two low-efficiency sensitivity cases.

These results can be explained with reference to the scenario framework in Section 2 and the assumptions surrounding key drivers of load. In the base year, peak loads are expected to be higher in summer (3.9 GW) than in winter (3.7 GW), primarily caused by high levels of air conditioning demand which constitutes a large

[67] For heat pumps, this also includes coefficients of performance.

portion of base core demand. In the 2020s, the network level load follows a similar trend in all scenario worlds, driven primarily by the connection of high voltage loads and uptake of electric heating.

The 2030s see the time of network peak shifting to winter, with load driven by heat pump uptake and electric vehicles. As these technologies become more established, they are taken up in large numbers especially in the more ambitious net zero compliant scenarios. These trends continue into the 2040s, however, increasing electricity demands are moderated by the uptake of renewable generation and storage, which also see an accelerated growth in the later years. The impact of efficiency measures is assumed to increase at an approximately constant rate over the full modelled timeline, with the more ambitious scenarios seeing a more rapid acceleration in the early years, followed by diminishing improvements in later years.

These effects are seen most clearly in the Net Zero 2040 pathway, which has one of the higher system peaks during the 2030s, but by 2050 it is the lowest of all six scenario worlds at 5.9 GW. Rapid uptake of low carbon technologies drive load growth in the early years, however, improvements in energy efficiency, both thermal and non-thermal, balance out this effect and having achieved full decarbonization by 2040, the system peak then begins to fall. By 2040, heating and transport have fully transitioned to low carbon alternatives, relying primarily on electric technologies such as EVs and heat pumps. After this point, the energy system continues to see a sustained growth in distributed generation and flexibility measures, which help to meet the high peak demands caused by early electrification. Furthermore, the 2040s see additional improvements in energy efficiency, which reduce overall energy consumption, as well as continued high levels of consumer engagement, shifting demand away from times of high grid congestion. As a result, this is the only scenario which sees a reversal of previous trends such that peak demand begins to decrease.

Consumer Transformation has a consistently low peak demand and is the lowest of all scenarios until the early 2040s. Many of the factors that produce this trajectory are shared with Net Zero 2040 including high consumer engagement, participation in flexibility markets and an overall shift towards a smarter energy system. However, decarbonization is achieved ten years later in this scenario due to the uptake of low carbon technologies following a more gradual trajectory compared to Net Zero 2040. Consequently, peak demand is lower in the early years, however the later years see the system peak plateau at approximately 6.5 GW.

The two low-efficiency sensitivity scenarios, which are based on Consumer Transformation and Net Zero 2040, illustrate the network impacts of high electrification coupled with low levels of distributed generation, efficiency, and flexibility. These scenarios show the network would experience higher peaks under these conditions and hence represent the highest possible constraints that Toronto Hydro's network might experience. Implicitly, these also represent the situations requiring the largest amount of network reinforcement and network investment. Over the modelled time period, the Net Zero 2040 sensitivity presents the highest peak load, due to assumptions surrounding the early adoption of low carbon technologies. However, the 2050 peak demand on both sensitivities is the same since both achieve full decarbonization, with a similar technology mix, by 2050.

Steady Progression has a consistently higher peak despite relatively lower levels of electrification, which can be largely attributed to lower levels of energy efficiency, distributed generation, and flexibility/storage. Consequently, the system peak in 2050 is projected to reach 7.4 GW. This scenario world illustrates clearly how a less ambitious decarbonization plan does not necessarily lead to lower electricity demand on distribution networks.

System Transformation has the highest system peak in 2050 out of all the main four scenario worlds. Until the late 2030s, it follows a similar trajectory to Steady Progression and Consumer Transformation, after which peak demand begins to increase at a faster rate, reaching 7.6 GW in 2050. The main cause of this is that, despite a partial reliance on retained gas infrastructure, this scenario world still assumes that electrification will be the primary route to decarbonization. However, System Transformation does not contain the same level of ambition in efficiency improvements, renewable generation, flexibility, and smart technologies. Therefore, the demands of high electrification are not offset to the same extent as in the Consumer Transformation and Net Zero 2040 scenarios.

Figure 75 shows the scale of the impact of flexibility, efficiency and behind-the-meter renewable generation on the summer and winter peaks in the Consumer Transformation and Net Zero 2040 scenario worlds. The value to the network of these measures is clearly largest in winter, though summer peak is still significantly reduced in both scenarios. The reduction of peak demand by more than a third (Net Zero 2040) would avoid the need for a significant amount of network reinforcement, and consequently would save Toronto Hydro a large amount of investment.

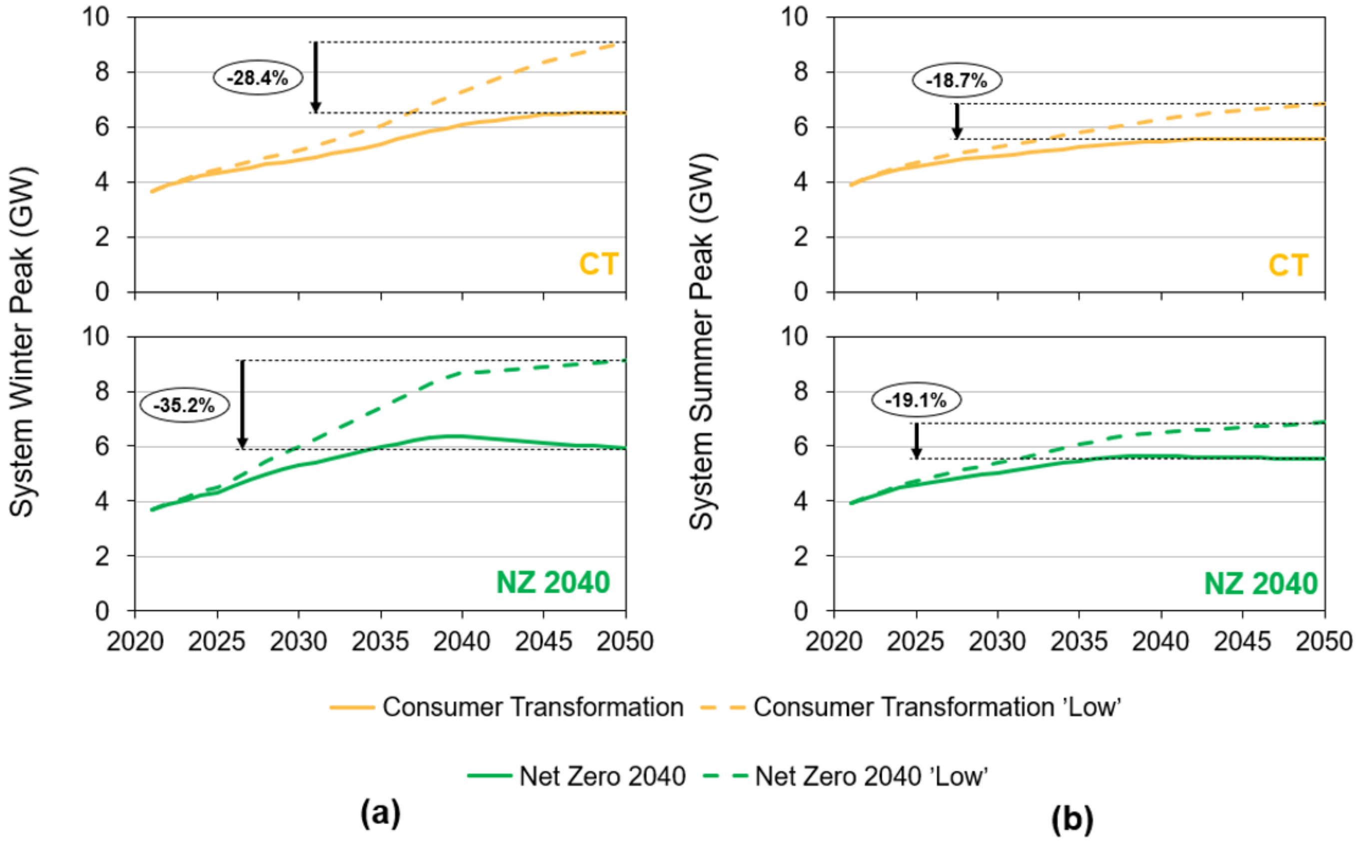

Figure 75: Comparison of peak true demand in the Consumer Transformation and Net Zero 2040 scenarios in (a) winter and (b) summer, in the Standard and Low-Efficiency sensitivity cases

6 Conclusions

This report has detailed the Future Energy Scenarios developed for Toronto Hydro that map out a number of future pathways for Toronto's energy system and evaluate the ways in which this may impact the distribution network. In order to capture the range of uncertainties in a coherent and meaningful way, four key 'scenario worlds' were developed, each built up of individual projections for different technology sectors. projections were developed using Element Energy's suite of bottom-up consumer choice and willingness-to-pay models which were informed by a comprehensive investigation into the current state of the energy landscape in Toronto, reviewing previous studies, datasets, and policy.

This work has found that, in all scenario worlds, Toronto can expect significant changes to its energy system resulting from electrification, renewable generation deployment, and improvements in energy efficiency. Peak demand increases are expected to be primarily driven by the electrification of heating and transport sectors which are expected to see widespread uptake of technologies such as electric vehicles and heat pumps. For example, in all net zero compliant scenario worlds, the transport sector sees a full transition to EVs across all vehicle types. Similarly, all domestic, commercial and industrial buildings are projected to be heated by heat pumps or electric resistive heating by 2050 for all scenarios that achieve net zero within this timeframe.

The nature of load changes on the distribution network is expected to vary considerably over the modelled time period. In the 2020s, electricity load growth is very similar across all scenario worlds, indicating that reinforcement is likely to be required regardless of the chosen decarbonization approach. This highlights the need for early planning to ensure the distribution network is well-prepared for near-term energy system changes.

In the 2030s, uptake of electric vehicles and heat pumps begins to accelerate, causing a shift in the time of network peak from summer to winter. In the later years, the high peak demands caused by the electrification of heat and transport are moderated by the uptake of renewable generation and storage, which see accelerated growth in the 2040s. Future generation uptake is anticipated to be dominated by solar photovoltaics, which in some cases may be accompanied by domestic battery storage systems. Uptake of batteries by industrial and commercial customers is also expected to increase, helping to further alleviate grid constraints.

Another significant outcome of this work is that it identified the need for changes to generation, storage, and energy efficiency to happen in parallel with electrification of demand. All of the core scenario worlds assume that efficiency improvements increase significantly from the present day, continuing to reduce energy consumption in future years. Without such changes, grid demands are expected to increase rapidly, as demonstrated by the two sensitivity scenario worlds. These pathways would necessitate significantly higher levels of investment to upgrade assets across the network.

Toronto Hydro's Future Energy Scenarios also highlight the importance of policy as a powerful tool in shaping the energy system. For example, in the low carbon heat uptake trends, the dominant factors in determining the uptake trajectories were the various assumptions regarding fossil fuel bans and financial incentives for cleaner technologies. This is of particular relevance to the attainment of a 2040 or 2050 net zero target, with the Future Energy Scenarios illustrating that this target will require key policy support for it to be achieved. There are many factors that can influence this at all levels of the energy system, but policy is one of the higher impact options observed in the modelling for accelerating the pace of change. Finally, the magnitude of changes to the energy system in recent years, both locally and globally, highlight the importance of maintaining an up-to-date understanding of the latest trends. Technological advancement, evolving supply chains, changing consumer attitudes, and evolving government policies have the potential to precipitate considerable impacts in technology deployment levels. As a result, regularly refreshing network load scenarios with the latest available data and learnings is an important part of planning for these changes and the low carbon energy transition.

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D5 2025-2029 Grid Modernization Strategy

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D5.1 Introduction: The Grid Modernization Imperative

Toronto Hydro is at an important turning point in its modernization journey. 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) – threatens to overwhelm grid capacities and capabilities in the long-term if not proactively addressed. To avoid both (i) long-term decline in system performance and (ii) becoming a barrier to the energy transition (in terms of both long-term costs to ratepayers and the grid's ability to serve and integrate customer loads and resources), Toronto Hydro has determined that it is necessary to accelerate strategic investment in specific field and information technologies that will deliver near-term benefits to customers while setting the utility on a path toward sustainable performance and improved efficiency as the pressures of climate change and the energy transition mount.

Trends, forecasts, and scenarios for the underlying drivers of the grid modernization imperative are covered in detail throughout Toronto Hydro's 2025-2029 Distribution System Plan, including in the following key sections:

- **Section D4** covers the projected impacts of decarbonization, electrification, and digitalization of the economy (e.g. data centre proliferation) on system utilization;
- **Section E3** provides an overview of Toronto Hydro's expectations for growth in DERs ("Distributed Energy Resources");[1] and
- **Section D2.1.2** discusses the impacts of climate change on grid performance and resiliency.

Toronto Hydro expects that the trifecta of electrification, DER proliferation, and worsening climate change will place increasingly complex demands on the utility's system assets and operations. The utility's central concern is securing its ability to continue delivering safe, reliable, and affordable electricity over the long-term and in the face of uncertainty. Climate change and electrification 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.

[1] In Toronto Hydro's system context, distributed energy resources are largely centered around solar technologies, energy storage systems, wind, natural gas, biogas, and customer assets for demand response programs. In the future, the term may expand to include micro-wind and fuel cells.

Furthermore, potentially high levels of DER penetration will add complexity and instability to the system, exacerbating the challenge of maintaining today's high standards of reliability and safety performance.

This escalation of risk and demand cannot be fully or efficiently met with a status-quo approach. Advanced, digital technologies will be necessary to upgrade the operating characteristics and capabilities of the grid, effectively unlocking incremental value from traditional infrastructure. These technologies – including sensors, remotely operable switches, next generation smart meters, predictive and prescriptive analytics, and automation schemes – will enable Toronto Hydro to not only adapt to the challenges it foresees in 2030 and beyond, but also take advantage of the opportunities presented by new kinds of customer-owned technologies such as battery storage and flexible loads for the benefit of all ratepayers.

D5.1.1 Toronto Hydro's 2025-2029 Grid Modernization Strategy

This document serves as a comprehensive overview of Toronto Hydro's 2025-2029 Grid Modernization Strategy and a guide to where the detailed investment plans can be found through the DSP ("Distribution System Plan"). As described throughout this summary document, Toronto Hydro has developed a grid modernization strategy which addresses emerging challenges and opportunities in a 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. From a materiality perspective, most of these investments are a continuation or renewal of programs that Toronto Hydro has been rolling-out at a gradual pace over the last two decades (e.g. grid sensors; remote-operable switches; smart meters), while others (e.g. achieving "self-healing" grid operations) represent the culmination of transformational efforts that have been a part of the utility's long-term modernization roadmap for many years. In many cases – including, for example, the introduction of mid-line reclosers and the implementation of a "self-healing" grid – Toronto Hydro's objectives are informed by the success of peer utilities in other progressive jurisdictions – including various U.S. states and Canadian jurisdictions such as Alberta – where investments in digital transformation and automation have proceeded at a more rapid pace in recent years.

Complimenting 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.

The remainder of this introductory section provides a brief overview of the differences between the traditional versus modernization grid. **Section 2** provides a detailed overview of the three major portfolios that constitute Toronto Hydro's Grid Modernization Strategy: (i) Intelligent Grid, (ii) Grid Readiness, and (iii) Asset Analytics & Decision-making. **Section 3** contains a series of appendices which provide more detailed discussions of certain key capabilities and projects that are not discussed in detail elsewhere in the DSP.

For a detailed summary of the how Toronto Hydro determined the expenditure levels for its 2025-2029 modernization programs and the role of Customer Engagement, please refer to Section E2 of the DSP. For an overview of how Toronto Hydro's modernization strategy is reflected in the utility's 2025-2029 key performance targets, please refer to Exhibit 1B, Tab 3, Schedule 1.

D5.1.2 Redefining Distribution Capabilities: The Traditional versus Modern Grid

In the traditional concept of the electric power grid in Ontario, seen in the top of Figure 1 below, the grid connects large central generating stations through a high-voltage transmission system to a distribution system that directly feeds customer demand. Generating stations consist primarily of nuclear- and hydro-powered turbines that spin to produce electricity. The transmission system in this model historically grew from local and regional grids into a large interconnected network that is managed by coordinated operating and planning procedures. Peak demand and energy consumption also grew at predictable rates, and technology evolved in a relatively well-defined operational and regulatory environment.

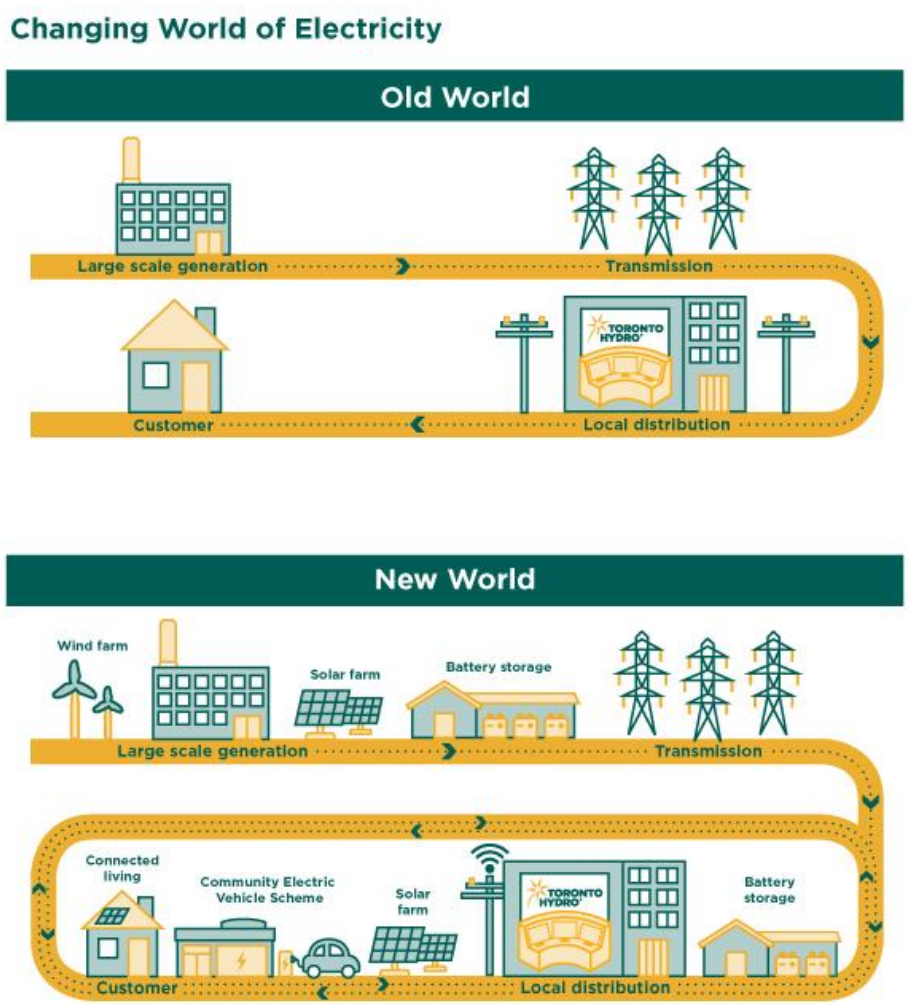

Figure 1: The Changing World of Electricity: Old vs New

The grid modernization imperative now requires utilities to go beyond "simply" delivering reliable one-way power to customers. Technology on the grid is changing, and the traditional, unidirectional model of electrical generation, transmission, and distribution is set to change with it. Segments of customers are poised to become prosumers: no longer will they only consume power, but they will also have the capability to supply the grid with power. At the same time, electrification will not only put additional load on the grid, but also create opportunities for flexibility and creative new solutions for load management. This represents an unprecedented challenge and opportunity to move the grid into a new era of reliability, availability, and efficiency that will contribute to economic, social, and environmental health and ensure that electricity can rise to the challenge of being the primary, and perhaps the only, source of energy in many consumers' lives. This will be made possible through proactive grid and operational investments to enable advanced monitoring and automation and digital transformation as seen in the lower half of Figure 4

Much of the required technology for the transition to a modernized grid already exists on the grid today, and in many cases, it is a matter of expanding its deployment to achieve sufficient granularity of grid transparency and control, and then building upon these field technologies with predictive and prescriptive analytics and automated controls. For example, sensors and remotely-operable SCADA ("Supervisory Control and Data Acquisition") switches have existed on the grid for quite some time, but using them to sense where a fault has occurred and remotely operating the SCADA switches to isolate the fault is the additional benefit of a modern, connected grid. A comparison of technologies in the traditional grid vs. the modern grid is summarized in Table 1 below.

Table 1. Traditional vs. Modern Grid.

Characteristics	Traditional	Modern / Smart Grid
Technology	**Electromechanical:** Traditional energy infrastructure is electromechanical. This means that it is of, relating to, denoting a mechanical device that is electrically operated. This technology is typically considered to be "dumb" as it has no means of communication between devices and little internal regulation.	**Digital:** The smart grid employs digital technology allowing for increased communication between devices and facilitating remote control and self-regulation.
Distribution	**One-way Distribution:** Power can only be distributed from the main plant using traditional energy infrastructure.	**Two-way Distribution:** While power is still distributed from the primary power plant, in a smart grid system, power can also go back up the lines to the main plant from a secondary provider. An individual with access to alternative energy sources, such as solar panels, can actually put energy back on to the grid.
Generation	**Centralized:** With traditional energy infrastructure, all power must be generated from a central location. This eliminates the possibility of easily	**Distributed:** Using smart grid infrastructure, power can be distributed from multiple plants and substations to aid in balancing the load, decrease peak time strains, and limit the number of power outages.

Characteristics	Traditional	Modern / Smart Grid
	incorporating alternative energy sources into the grid.	
Sensors	**Few Sensors:** The infrastructure is not equipped to handle many sensors on the lines. This makes it difficult to pinpoint the location of a problem and can result in longer downtimes.	**Sensors Throughout:** In a smart grid infrastructure system, there are multiple sensors placed on the lines. This helps to pinpoint the location of a problem and can help re-route power to where it is needed while limiting the areas affected by the downtime.
Monitoring & Control	**Manual Monitoring, Limited Control:** Due to limitations in traditional infrastructure, energy distribution must be monitored manually.	**Self Monitoring, Pervasive Control:** Monitors itself using digital technology, allows it to balance power loads, troubleshoot outages, and manage distribution without need for direct intervention from a technician.
Restoration	**Manual:** In order to make repairs on traditional energy infrastructure, technicians have to physically go to the location of the failure to make repairs. The need of this can extend the amount of time that outages occur.	**Self-Healing:** Sensors can detect problems on the line and work to do simple troubleshooting and repairs without intervention. For problems related to infrastructure damage, the smart grid can immediately report to technicians at the monitoring centre to begin the necessary repairs.
Customer Choices	**Fewer:** The traditional power grid system infrastructure is not equipped to give customers a choice in the way they receive their electricity. Alternative energy sources, for example, have to be separated from power plants and traditional grid infrastructure.	**Many:** Using smart technologies, infrastructure can be shared. This allows more participants and forms of alternative energy to come on the grid, allowing consumers to have more choice.
Flexibility	Non-Flexible and Non-Controllable Loads	Flexible and Controllable Loads

D5.2 Grid Modernization Strategy Overview

The Grid Modernization Strategy outlines a five-year plan with objectives for accelerating the transformation of Toronto Hydro's existing grid infrastructure into a more technologically advanced distribution system. The overall goal of this strategy is to deliver on the utility's long-term vision of improving reliability and resiliency, efficiently accommodating and managing an expected influx of DERs, and preparing for electrification across various sectors. It also aims to leverage improved grid observability (i.e. real-time data from sensors) and advanced analytics to enable data-driven decision-making for applications such as predictive asset management, grid planning and optimization, and load forecasting.

The strategy focuses on three core areas as shown in Figure 2 below, namely: Intelligent Grid, Grid Readiness and Asset Analytics & Decision-making. Technology serves as the binding force to enable interconnection between the three core areas.

Figure 2: The Grid Modernization Pieces

The **Intelligent Grid** area is focused on expanding observability and controllability of the grid such that automated tools like FLISR ("Fault Location, Isolation, and Service Restoration") and ADMS ("Advanced Distribution Management System") are able to provide enhanced fault restoration capabilities, improve operational efficiency, and better optimize system configuration and real-time performance. The **Grid Readiness** area focuses on building capabilities to support decarbonization and decentralization of energy resources, with a focus on leveraging field technologies and analytics, including major platforms like DERMS ("Distributed Energy Resource Management System" or "Energy Centre"), to better facilitate DER connections and optimize DER capabilities for services such as demand response. The last area, **Asset Analytics & Decision-making**, encompasses the digital advancements required to lay the foundation for a future-proof digital core that can support the large volumes and varieties of data obtained from initiatives in the other two core areas, leverage advanced analytical capabilities to extract more value from current assets, and drive greater efficiency in investment planning.

The following sections present details about the three focus areas and strategic initiatives tied to them.

D5.2.1 Intelligent Grid

The ***Intelligent Grid*** portfolio within the Grid Modernization Strategy is designed to improve reliability, resiliency and situational awareness of the distribution system. The portfolio places a strong emphasis on harnessing the power of advanced field technologies and operational systems to enhance grid intelligence and responsiveness. The key components of Toronto Hydro's Intelligent Grid concept are illustrated in Figure 3 below.

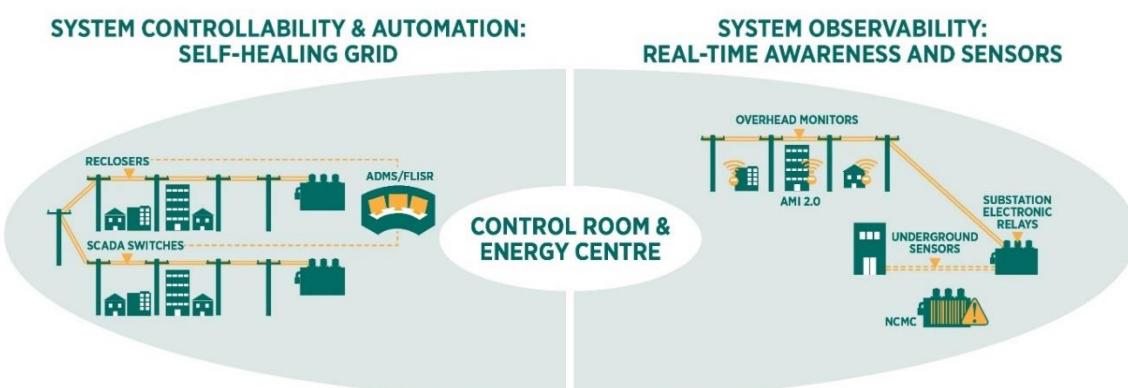

Figure 3: The Major Components of an Intelligent Grid

Investments in this portfolio aim to strengthen two domains of the distribution system, namely: System Observability and System Controllability and Automation.

- **System Observability: Real-Time Awareness & Sensors** entails adding more sensors, relays and monitoring technology at specific nodes across the distribution grid, including customer meters. These assets will provide additional data collection points across the grid, which Toronto Hydro will leverage to improve overall situational awareness ("grid transparency"), facilitate quicker fault location, and gain access to important insights at the edge of the grid. This data will be used in conjunction with advanced analytics platforms to analyze variables such as voltage levels, asset loading, and power flows. Improved system observability will help Toronto Hydro proactively identify developing issues, respond promptly to events, and utilize available resources efficiently.
- **System Controllability & Automation: Self-Healing Grid** entails (i) adding more switching assets on the grid – mainly SCADA-controlled tie switches, sectionalizers, and reclosers – and (ii) implementing automation technologies including FLISR ("Fault location Isolation and System Restoration"). The switching devices will provide Toronto Hydro with greater control and flexibility over grid operations, allowing remote switching and monitoring and improved fault isolation and restoration. With increased system controllability, Toronto Hydro can respond swiftly to changing conditions, optimize grid performance in real-time, reduce the number of customers impacted and the duration of interruption during faults or disruptions, and reduce truck rolls. These investments will also establish the basis for a "self-healing," automated grid, which Toronto Hydro aims to implement beginning in 2030 following planned upgrades to the utility's ADMS (which includes the FLISR technology that is required to enable distribution automation).

Section D5.2.1.1 and D5.2.1.2 below provide additional details on each of these categories. For a high-level summary of all the initiatives and investment programs that constitute the Intelligent Grid portfolio, refer to Section D5.2.1.3.

D5.2.1.1 System Observability: Real-Time Awareness and Sensors

Expanding visibility into the operating conditions of the distribution grid is a critical part of Toronto Hydro's *Intelligent Grid* strategy for 2025-2029, and will help the utility achieve three core capabilities:

1. **Enhanced Fault Location:** Locating faults and other system disturbances faster and more efficiently in order to improve reliability and operate the grid more cost-effectively.
2. **Enhanced Decision-making and Grid Optimization:** Providing greater insight into real-time feeder and asset loading, condition, and other relevant operating characteristics. This assists the utility in managing short- and long-term uncertainty as well as driving optimal real-time operational decisions and longer-term investment planning decisions.
3. **Enhanced Asset Diagnostics:** Greater visibility into high-risk and previously hard-to-monitor assets will improve asset diagnostics, mitigating the risk of asset failure and impacts to personnel safety and environmental damage.

The most significant investment Toronto Hydro is making to enhance grid observability in the 2025-2029 rate period is the replacement of end-of-life, legacy smart meters with next generation smart meters (also known as Advanced Metering Infrastructure 2.0 or “AMI 2.0”). While AMI 2.0 has the long-term potential to provide the high frequency, multi-parameter insights that will be required to address certain emerging operational pressures and requirements, many of the potential benefits and use cases for AMI 2.0 are currently untested and will require significant investment in data analytics, digital systems integrations, and business process changes. 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 planning to explore and leverage a broader suite of field technology investments for the 2025-2029 period within the System Enhancements investment program (Exhibit 2B, Section E7.1).

This will involve the targeted 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. To achieve these benefits, the System Observability segment (Section 7.1.1.3) will deploy several sensory assets, such as overhead and underground powerline sensors, online cable monitors, and transformer monitors. The NCMC (“Network Condition Monitoring & Control”) (Exhibit 2B, Section E7.3) and Stations Renewal (Exhibit 2B, Section E6.6) programs add further monitoring and communications capabilities to various aspects of the distribution system.

Toronto Hydro expects that investments to improve observability will deliver both tactical operational benefits and long-term asset management benefits. As the distribution grid becomes more complex – with the addition of more devices and evolving customer interactions with the grid – it is essential that investments in grid observability keep pace, allowing Toronto Hydro to make informed operational and asset management decisions. Targeted observability investments will enable more detailed insights into power flows by leveraging data from deployed field devices, in addition to more granular customer consumption data via AMI 2.0. The objective is to provide an accurate view of the state of the distribution grid, for applications such as automated fault management, DER management, and asset condition management. Furthermore, field devices such as sensors are significantly less expensive than building out new infrastructure to accommodate load growth. While these devices do not themselves provide additional capacity, they can be leveraged in targeted ways to ensure that Toronto Hydro's demand forecasts and assumptions are informed by increasingly granular information, and that appropriately sized capacity investments are planned for the right parts of the system at the right time. They will also help capacity optimization as well as more effective non-wire solutions planning and operations.

Investment programs within the System Observability portfolio will focus on service areas with significant operational value (e.g., DER-rich feeders, feeders with poor visibility, feeders with poor reliability, etc.). Before rolling out new observability technologies at scale, Toronto Hydro will run smaller pilots to test the technology for specific use cases, ensuring that the benefits are clear for customers, and that sufficient time is allotted to pursue potential overlapping use cases related to AMI 2.0. Ultimately, Toronto Hydro is looking to gain a broad range of experience developing applications and use cases for potentially scalable sensor technologies and AMI 2.0 in the 2025-2029 rate period, with the goal of initiating a fully formed observability strategy in 2030-2034.

The portfolio objectives will be primarily addressed through the following initiatives, which are summarized in the section below.

1. Deployment of Overhead and Underground Sensors
2. Online Cable Monitoring
3. Transformer Monitoring
4. Network Condition Monitoring & Control
5. Stations Digital Relays
6. AMI 2.0

D5.2.1.2 System Controllability & Automation: Self-Healing Grid

In Toronto Hydro's grid modernization journey, System Controllability and Automation will continue to play a vital role in transforming the grid into an intelligent and responsive system. System controllability refers to the ability to actively manage and control grid operations in real time using remotely operated devices. These devices provide significant reliability and efficiency benefits in and of themselves, and are also the essential physical nodes which create the basis for a "self-healing" grid, i.e. a grid that can detect, isolate, and fix faults and disturbances in the grid in real-time, with minimal or no human intervention. The self-healing aspect is ultimately enabled by implementing advanced operational control technologies such as FLISR.

1. Preparing the Horseshoe System for Automation by 2030

One of the most significant objectives for Toronto Hydro's Grid Modernization Strategy in the 2025-2029 rate period is to advance the ongoing process of readying Horseshoe system feeders for the transition to a **self-healing operation beginning in 2030**.[2] Specifically, Toronto Hydro is aiming to have 90 percent of feeders in the Horseshoe system ready for automation by 2030. This will be accomplished in part through the System Enhancements program, which will install SCADA-controlled switches and reclosers on at least 34 feeders to bring them to the minimum optimal number of switching points per feeder of 2.5, which is required to enable an effective self-healing automation scheme.[3]

The other essential part of Toronto Hydro's strategy toward preparing a self-healing grid is FLISR implementation. FLISR is a centralized software system that works to automatically detect the location of a fault, isolate the affected section of the network, and reroute power to as many customers as possible, while minimizing the impact on the overall system. FLISR works together with the aforementioned physical field devices to enable distribution automation.

Implementing fully automated FLISR within Toronto Hydro's dense, urban service territory is a complex and significant undertaking which the utility plans to address using a methodical and staged approach over the 2025-2029 rate period. The utility is planning to implement "manual FLISR" at an average of five transformer station areas per year between 2025 and 2028, ultimately covering all 20 transformer stations in the Horseshoe area prior to 2030. Manual FLISR refers to the concept of running the FLISR system in the control room where the system suggests switching instructions to the operators to execute for power restoration. This affords system controllers the opportunity to review the FLISR system's prescribed switching operations to ensure they are safe and appropriate before implementing the switching plan. Running manual FLISR for an adequate period of time is an

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[2] The Horseshoe system is the open-loop primary distribution system that serves all of the City of Toronto's inner suburbs.

[3] The 2.5 standard refers to the need for a feeder to have a minimum of two SCADA-controlled sectionalizing points and one SCADA-controlled tie-point, with the latter counting as 0.5 because it belongs to two feeders simultaneously.

important stepping-stone toward implementing automatic FLISR as it ensures that automation can be implemented with the necessary confidence that it will function properly, with the intended benefits and minimal risk to safety and system integrity. In parallel with the roll-out of manual FLISR, Toronto Hydro plans to make essential upgrades to its ADMS platform in 2025-2029, readying those systems to support fully automated FLISR in 2030 and beyond.

A U.S. Department of Energy report on five utilities that implemented FLISR projects found that, on average, FLISR reduced the number of CIs ("Customers Interrupted") by up to 45 percent and reduced the CMIs ("Customer Minutes of Interruption") by up to 51 percent for a relevant outage event. This was generally consistent with utility expectations of system performance going into the projects. Fully automated switching schemes generally outperformed operator-initiated remote switching schemes.[4] Toronto Hydro expects to see significant benefits from its roll-out of automatic FLISR in 2030 and beyond.[5] Note as well that, as discussed in the U.S. Department of Energy's final report on the results of its Smart Grid Investment Grant Program, utilities that successfully integrated their distribution automation schemes with observability enhancing technologies were able to "remotely pinpoint the location and extent of outages, better direct resources, and equip repair crews with precise, real-time information – often shaving hours or days off restoration time following major storms."[6]

Benefits such as these are a critical part of ensuring Toronto Hydro's grid is capable of cost-effectively delivering improved reliability and resiliency in anticipation of electrification and pressures from adverse weather. However, to be positioned to fully realize these benefits, the utility must invest in completing the milestones outlined above.

For more information on Toronto Hydro's FLISR system, please refer to Section D5.3.2.

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[4] U.S. Department of Energy, Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration, https://www.smartgrid.gov/files/documents/B5_draft_report-12-18-2014.pdf

[5] It is important to note that the benefits cited from the U.S. Department of Energy Study rely upon the US standard for momentary outages of <5mins. Percentage improvements may be lesser for Toronto Hydro given the standard of <1min for momentary outages in Ontario. Regardless, the positive effective on the lived reliability experience of customers will be the same or similar. Note that the level of FLISR benefits achieved by a given utility is also dependent on that utility's unique operating reality.

[6] U.S. Department of Energy, Smart Grid Investment Grant Program Final Report Executive Summary, https://www.energy.gov/sites/prod/files/2017/03/f34/Final%20SGIG%20Report%20-%20Executive%20Summary.pdf

2. Additional Controllability Investments to Improve Reliability, Resiliency and Grid Flexibility

As noted earlier in this section, even without the advanced benefits of automated FLISR, the deployment of incremental remote-operable switching devices will have material benefits for reliability, resiliency and operational flexibility. Therefore, in addition to completing the "self-healing grid" strategy discussed above, Toronto Hydro is planning to continue deploying SCADA-controlled devices more broadly as part of the System Enhancements program. This includes continuing to deploy additional sectionalizers and tie switches on the feeders most in need of additional switching capabilities.

As a general design guideline for area rebuilds and new feeders, Toronto Hydro requires that there be no more than approximately 700 customers within a switching region or section. Currently, many feeders on Toronto Hydro's system do not meet this standard, meaning that these feeders have relatively limited flexibility to deal with certain contingency events and interruptions. This results in sub-optimal levels of reliability performance risk for affected customers. In 2025-2029, to support its reliability targets and improve the operational flexibility of the Horseshoe and Downtown overhead systems, Toronto Hydro is planning to install 298 SCADA operated switches and 220 reclosers, prioritizing feeders with the worst reliability performance and greatest reliability risk levels. For a detailed overview of these investments, refer to the Contingency Enhancement segment within the System Enhancements program (Section E7.1).

Note that reclosers are a new feature of Toronto Hydro's portfolio of grid technologies. A recloser is a device which automatically detects and interrupts fault conditions, and then re-establishes connectivity if the fault condition has been cleared. In other words, when a transient fault occurs downstream of a recloser (like a tree branch touching a line), the recloser will temporarily open the circuit to clear the fault and then automatically reclose it, restoring power. If the fault is persistent, the recloser will typically operate a pre-set number of times before locking out (remaining open) to ensure safety, automatically isolating faulted sections of the feeder such that customers on healthy feeder sections do not experience an interruption. Reclosers provide benefits to the system by substantially reducing the number of customers who experience a sustained interruption under certain high-impact fault scenarios.

Toronto Hydro completed a recloser deployment pilot project in early 2023, which successfully demonstrated that modern recloser technologies can work effectively on the utility's distribution system and that these units have the potential to contribute material improvements in the number of customers impacted by sustained outages in many of the higher-impact fault scenarios Toronto Hydro deals with on a regular basis.[7] Importantly, reclosers can also be operated remotely, much like a SCADA-operable load break switch, meaning that they will also form an integrated part of Toronto Hydro's FLISR-enabled distribution automation scheme. By targeting high-priority locations and responding to customer concerns, Toronto Hydro will enhance its ability to restore power quickly during outages, including high-impact contingency events such as major storms.

With the combination of these switching investments, Toronto Hydro expects to see benefits in CI ("Customer Interruptions") and CMO ("Customer Minutes Out"), as well as operational cost savings. Overall, Toronto Hydro estimates that by 2030, there will be improvements in the range of three to seven percent for SAIFI and four to seven percent for SAIDI on the overhead system due to Contingency Enhancement investments. Toronto Hydro has also estimated operational cost savings from the deployment of its SCADA switches to be about $22,500 per switch over its lifetime.[8] Finally, Toronto Hydro has also estimated the quantified customer reliability benefits of its 2025-2029 Distribution System Plan, which includes the benefits of additional switches and reclosers. This analysis can be found in Exhibit 1B, Tab 3, Schedule 1.

3. Advanced Distribution Management System ("ADMS") Upgrades

The FLISR capabilities discussed in the automation section above are part of a broader software solution known as an ADMS. At its core, an ADMS is a software solution that integrates and consolidates functionalities from several systems, such as the utility's Outage Management System ("OMS") and Distribution Management System ("DMS"), which handle a wide array of mission-critical outage management and distribution system management functions; SCADA, which enables real-time monitoring and control; and the DER Management System or DERMS, which monitors and controls DERs. The role of an ADMS is to provide the utility with a comprehensive and unified view

[7] Microprocessor relays employed in the latest generation of reclosers are able to identify the different types of faults that occur and be programmed to provide a faster, more appropriate response. Prior to this development, protection schemes – specially in high density areas with short feeders like the City of Toronto – often had to choose security and dependability over reduction in response times and increased feeder segmentation. Today's feeder protection devices must be ready to respond to more dynamic situations and the new generation of reclosers with microprocessor relays are key in this regard to address emerging challenges by improving segmentation and protecting Toronto Hydro's circuits and assets.

[8] Based on average truck roll cost of $300 per hour for one-hour, average number of SCADA switch operations per year (calculated over 2018-2022), and an average switch lifetime of 25 years.

of its operations by acting as a central hub which pulls data from, and interacts with, this constellation of software and systems.

Toronto Hydro's ADMS is poised to play an increasingly significant role in the utility's operations. As the grid evolves with the integration of distributed energy resources, electric vehicles, smart devices, and changing consumption patterns, the complexities of managing the network will also increase. The utility will require its ADMS to optimize the integration and management of DERs, leverage real-time data processing capabilities and analytics to manage the two-way flow of electricity and information as the grid becomes smarter, perform more advanced outage management functions (including FLISR), manage demand response programs, and leverage enhanced analytics and data integration to improve system and operational efficiency.

As part of its Intelligent Grid strategy for 2025-2029, Toronto Hydro plans to upgrade its existing systems into an ADMS platform that better integrates "best-fit" system components and will be capable of meeting the emerging demands on the grid while enabling efficiencies. Given the critical nature of these systems to Toronto Hydro's day-to-day operations and overall system reliability and security, technical upgrades are necessary in 2025-2029 to ensure the ADMS components have continued vendor support. Furthermore, many of Toronto Hydro's ADMS components 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 ensure optimal components are enabled and these components are effectively integrated. These upgrades will also support future automation functionalities (e.g. in support of the self-healing grid) and improve business process efficiencies.

For more information on Toronto Hydro's planned ADMS upgrade project, please refer to Exhibit 2B, Section E8.4.

D5.2.1.3 Intelligent Grid Program Summaries

The Intelligent Grid technologies introduced above are summarized in Table 2. For more detail on each technology, please refer to the Investment Program column. For select technologies, more detail has been provided in the appendices of this strategy.

Table 2. Intelligent Grid Program Summaries

Capability Domain	Technology	Benefits	Costs (2025-2029)	Investment Program
System Observability	Overhead & Underground Sensors	• Improves outage response time and quicker service restoration for customers • Improves SAIDI & SAIFI metrics through data that enables proactive asset management • Provides data for advanced analytics platforms and data-driven asset management decision-making	$4.7M	Exhibit 2B, Section E7.1 - System Enhancement
	Online Cable Monitoring	• Identifies cables at risk of failure before failure • Provides insights on assets that are difficult or costly to inspect; • Monitors load growth and allows for proactive prioritization of capacity availability • Saves operating expenditures and • Reduces planned outage times through proactive cable maintenance		
	Transformer Monitoring	• Real-time transformer monitoring to identify early signs of failure • Provides additional information for diagnostics and future asset management purposes • Enables the data necessary for more granular system forecasting		

Capability Domain	Technology	Benefits	Costs (2025-2029)	Investment Program
	Network Condition Monitoring & Control (NCMC)	• Reduces flooding-related equipment damage; • Enables the early detection of conditions that can cause vault fires to improve response time and mitigate damage and safety risks; • Provides real-time loading data and remote switching capabilities • Reduces the need for crews to perform inspections	$6.0M	Exhibit 2B, Section E7.3 -Network Condition Monitoring & Control
	Stations Digital Relays	• Accommodates increasingly sophisticated customer needs, including DER integration; • Enables Toronto Hydro to operate its system more efficiently by increasing observability and controllability; • Allows for fault recording for historical view of issues; • Provides relay diagnostics for easier maintenance; • Improves fault coordination	$48.9M	Exhibit 2B, Section E6.6 - Stations Renewal Narrative
	AMI 2.0	• Contributes to reliability objectives by enabling dispatchers to more effectively direct field crews due to last gasp capabilities. • Improves response time for emergency response and outage restoration activities that require customer level outage information • Improves the cost-effectiveness of planning and operational decision-making • Increases visibility into the distribution system particularly at the edge of the grid • Enhances load forecasting and future demand forecast at secondary transformer level using more granular data • Enables more accurate residential load profiles to support efficient resource allocation	$248.1M	Exhibit 2B, Section E5.4 -Metering Narrative

Capability Domain	Technology	Benefits	Costs (2025-2029)	Investment Program
System Controllability & Automation	SCADA Switches	• Reduces fault isolation times on targeted feeder trunks • Reduces average duration of outages for targeted feeders by installing SCADA-enabled tie and sectionalizing points • Reduces the duration of sustained interruptions; • Reduces the time to locate and clear faults; • Enables technologies such as FLISR	$132.9M	Exhibit 2B, Section E7.1 - System Enhancement
	Reclosers	• Reduces the time to locate and clear faults • Reduces the number of customers impacted on a feeder outage • Increases grid efficiency by differentiating between temporary and sustained faults • Enhances observability since reclosers are equipped with advanced monitoring capabilities • Improves reliability upstream of device		
	FLISR	• Improves reliability by quickly detecting and isolating fault, minimizing number of affected customers and reducing outage durations • Improves resiliency to faults and disruptions by minimizing the impact of incidents thereby improving overall grid resilience (such as customers affected during outage resulting in reduced economic losses for customers and businesses)	$34.2M	Exhibit 2B, Section E8.4 - IT/OT Systems

Capability Domain	Technology	Benefits	Costs (2025-2029)	Investment Program
	ADMS	• Improves grid reliability, reduces outage durations, enhances efficiency and increases customer satisfaction through consolidation of intelligent-device data for increased situational awareness and state estimation • Enhances outage restoration by providing real time situational awareness, automating FLISR workflows and facilitating increased coordination between field crew and control centre • Increases data analysis for data-driven decision making, optimizing grid operations, enhancing system reliability, optimizing asset utilization and identifying energy conservation opportunities		

D5.2.1.4 Intelligent Grid Track Record

Toronto Hydro has a proven track record of effectively implementing Intelligent Grid initiatives and realizing key benefits for customers. This section highlights two major examples of Intelligent Grid accomplishments from recent years: Network Condition Monitoring & Control and Contingency Enhancement.

1. Network Condition Monitoring & Control

Toronto Hydro developed and implemented its NCMC ("Network Condition Monitoring and Control") program in order to increase situational awareness on the low voltage secondary distribution network, with the objective of improving system reliability, environmental performance, and operational efficiency of the network. As discussed in the program evidence (Section E7.3), the NCMC program, which was launched in the latter part of the 2015-2019 period, has represented 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 in 2006-2008. Toronto Hydro believes that the lessons learned, skills developed, organizational capacity gained, and customer benefits realized through this experience will prove foundational to the successful and efficient implementation of the Intelligent Grid roadmap for 2025-2029.

Toronto Hydro plans to complete the initial scope of the NCMC program by 2026, after which the utility will begin to pilot additional capabilities that could be added to network vaults in the future. As of the end of 2022, the utility has completed over a third of the program and achieved the following benefits from enhanced observability (i.e. water level sensors, vault and transformer operating temperature sensors, oil level and tank pressure sensors, and real-time loading data) and controllability (i.e. remote switching) within its network vaults:

- Over the last two years, the utility has responded to:
  - 56 **water level alarms**, helping to prevent potentially catastrophic vault flooding
  - **temperature alarms** in 14 vaults, allowing for pre-emptive response to potentially catastrophic failures
  - 34 **low oil alarms,** which have helped Toronto Hydro substantially reduce the incidence of high-volume oil spills (see Figure 3 in Section E7.3).

- In the second half of 2022, Toronto Hydro saved approximately $79,000 in operating costs by **remotely checking protectors** (e.g. after heavy rainfall events) in commissioned vaults rather than sending trucks and crews.

- In the first half of 2023, Toronto Hydro has saved approximately $120,000 through the **reduced need to deploy crews to vaults during switching events.**

- 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.

- 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.

Toronto Hydro expects these benefits to scale as program implementation continues through 2023-2025. For more information on the progress and benefits of NCMC, refer to Section E7.3.

2. Contingency Enhancement (Horseshoe System Controllability)

Toronto Hydro has been steadily modernizing its Horseshoe distribution system for many years through both its System Renewal efforts and complimentary System Service programs including the Contingency Enhancement segment (Section E7.1). A primary focus of these efforts has been the deployment of SCADA-operated switches which allow control room operators to remotely transfer load and isolate feeder sections under fault conditions or on a planned basis. Figure 4 below shows the number of switches Toronto Hydro has installed per year since 2005.[9]

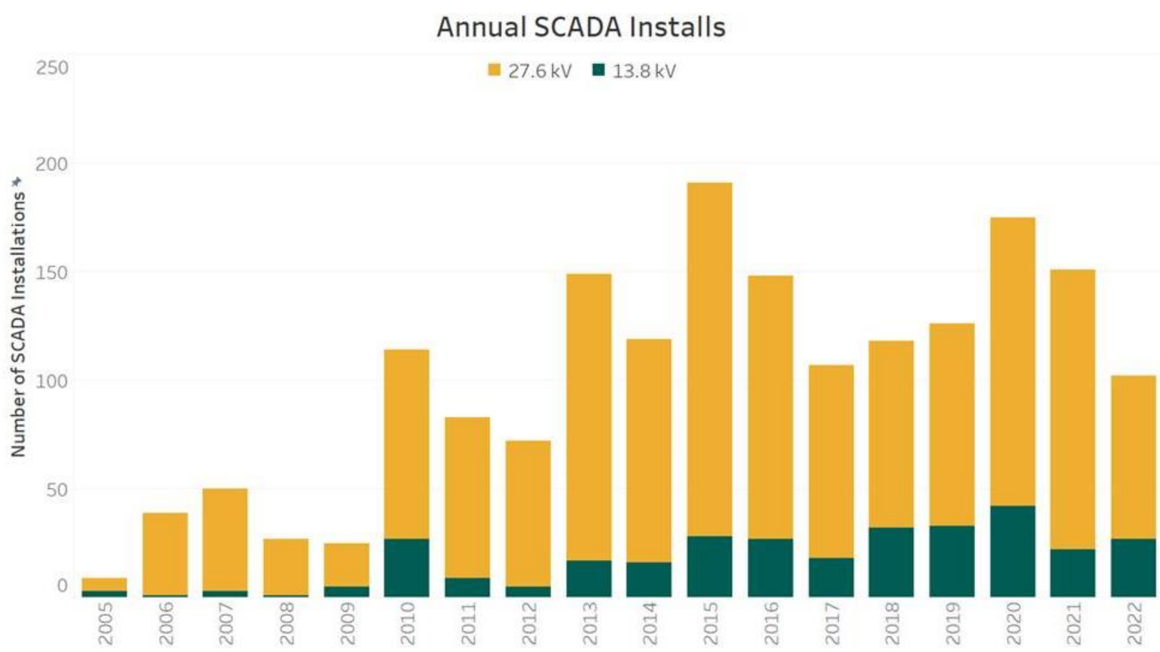

Figure 4. Annual SCADA Switch Installations (2005-2022)

[9] This graph represents all SCADA installations throughout the system, including those not installed through the Contingency Enhancement program.

As discussed in Section E7.1.3.1, these investments have been an important contributor to Toronto Hydro's improving reliability performance over the last decade. Adding SCADA switches (which includes replacing old manual switches with SCADA switches) on a feeder has also had other benefits, including avoided truck rolls and reduced outage restoration efforts in certain contingency scenarios, and reduction of safety risks by reducing the need for manual switching.

As discussed above, these existing switches, combined with the switches and reclosers to be installed throught2023 to2029, will form the physical basis for Toronto Hydro's self-healing grid in 2030 and beyond. Once implemented, Toronto Hydro expects self-healing grid capabilities to deliver significant additional value from these field devices in the form of substantial incremental reliability improvements.

D5.2.2 Grid Readiness

With advancements in technology and the societal imperative to decarbonize the energy system, Toronto Hydro expects the market for DER adoption to continue to mature and expand, likely at an accelerating pace. In response, the utility is planning for a scenario of rapid growth for various types of distributed resources and technologies, including rooftop solar systems, behind-the-meter battery storage systems, and demand response technologies. However, the utility's ability to integrate DG ("Distributed Generation") at pace with planning scenarios is challenged by (i) the precisely calibrated protection schemes potentially mis-operating, compromising the ability of the grid to operate safely and reliably; and (ii) lack of effective tools to analyze and enable interconnection as applications become increasingly complex. If projects materialize and they are integrated well, DG, and more broadly DERs, can play a role in shifting reliance away from the bulk system, supporting an adaptable and resilient distribution network, and empowering consumers to actively participate in the energy ecosystem and clean energy transition.

As the rate of DER uptake increases, it is essential for Toronto Hydro to reinforce the grid to effectively accommodate and integrate these technologies. To this end, Toronto Hydro's Grid Readiness portfolio, illustrated in Figure 5, is dedicated to enhancing what the utility views as the four critical functions of the DER enablement cycle: facilitating, leveraging, monitoring and forecasting, and innovating.

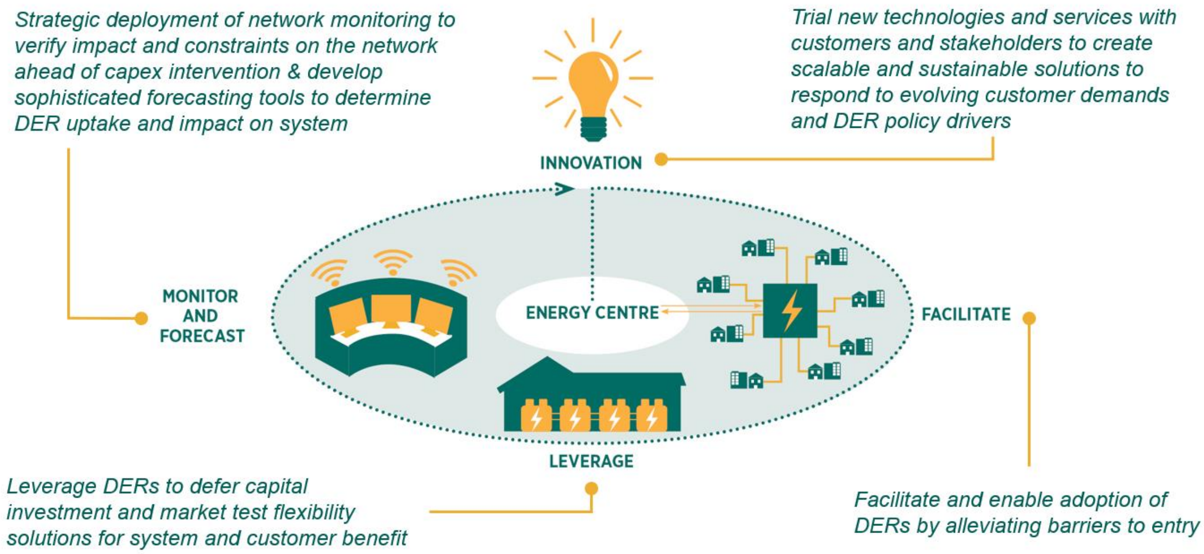

Figure 5: Major Components of the Grid Readiness Strategy

Toronto Hydro has grouped Monitoring and Forecasting together to establish the following three capability domains within the Grid Readiness portfolio:

- **Facilitating DER Connections** entails alleviating DER connection constraints on the grid where feasible and simplifying the process for customers and stakeholders seeking to connect their DERs to the grid. By improving the connection process and providing accessible, high quality geospatial data, Toronto Hydro aims to remove barriers to DER uptake and deliver an end-to-end high-quality customer journey.

- **Leveraging DER Connections** entails harnessing the capabilities of connected DERs to enhance grid flexibility and reliability, and supporting demand response programs in pursuit of grid optimization. Leveraging the inherent flexibility and capabilities of DERs means Toronto Hydro can address the changing dynamics of the grid, adapt to evolving customer needs, and build resilient energy infrastructure for the future.

- **Monitoring and Forecasting DER Connections** entails positioning Toronto Hydro to anticipate, analyze, and manage the impacts of DERs on the grid along various relevant timescales and at the necessary levels of granularity, thereby giving the utility the greatest chance at successfully building for, and optimizing the utilization of, DERs on its system over the long-term.

Progress in these three domains will also be supported in 2025-2029 by an **Innovation program**, which is summarized in Section D5.2.2.4.

Overall, the strategy in these four critical functions is to continue in the direction of adapting and transforming today's grid into a future-ready smart and flexible grid that, by 2030, is not only prepared to cost-effectively accommodate the accelerating growth of DERs, but also is able to take advantage of the broader potential of DERs to enhance system efficiency, reliability, adaptability, and sustainability for all customers. Failure to pursue these capabilities and innovations in 2025-2029 risks positioning Toronto Hydro as an unwelcome barrier to the potential for widespread DER adoption in the City of Toronto.

D5.2.2.1 Facilitating DER Connections

Toronto Hydro is forecasting a nearly 70 percent increase in connected DER capacity by the end of 2029, though that figure could be higher or lower depending on how potential drivers of DER uptake (e.g. government policy) align to encourage and support a faster uptake.[10] Longer-term, Toronto Hydro's Future Energy Scenarios study projects that the amount of renewable distributed generation and battery storage capacity connected to the grid could grow by as much as 540 percent by 2035 under the "High" scenario and as much as 1,350 percent by 2050, as shown in Figure 6**Error! Reference source not found.**[11,12]

[10] Refer to Exhibit 2B, Section E3 for a comprehensive discussion of forecasted DER connections in 2025-2029.
[11] Renewables in the FES study largely consist of rooftop and ground-mounted solar
[12] Refer to Exhibit 2B, Appendix E for a detailed explanation of policy drivers for each of the scenarios

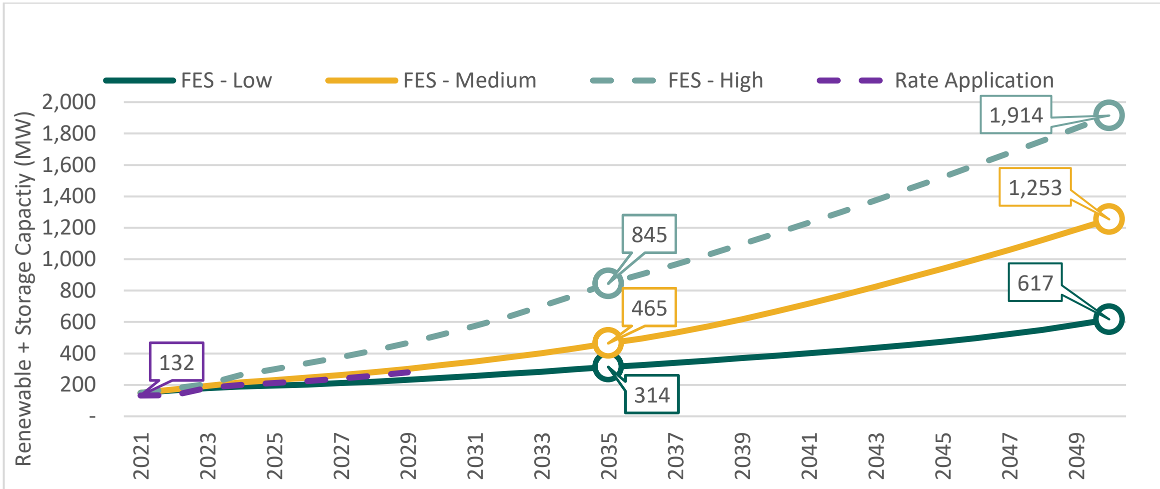

Figure 6: Future Energy Scenarios Renewable + Storage DER Connected Capacity Projections (in MW)

As discussed in detail in Exhibit 2B, Section E3, there are a number of safety and reliability constraints limiting Toronto Hydro's ability to connect DERs, including short circuit capacity, thermal limits, anti-islanding measures, and the ability to transfer loads between feeders in the event of a contingency. While these technical limitations are not widespread on Toronto Hydro's system today, the pace of DER adoption contemplated in the energy transition could lead to pervasive challenges that would make it necessary for the utility to turn away increasing volumes of connection applications.

With this context in mind, Toronto Hydro is planning a number of proactive investments and initiatives that are grouped under the Facilitating DER Connections domain of its Grid Modernization Strategy. These initiatives are intended to achieve the following strategic outcomes:

1. Simplify the process for customers and contractors seeking to connect DERs to the grid;
2. Develop tools to help customers and clean technology investors identify efficient locations to install DERs on the grid;
3. Equip Toronto Hydro with high quality data to anticipate, analyze, and assess DER applications; and
4. Alleviate technical barriers to connecting DERs by investing in additional hosting capacity.

Customers looking to connect DG and ESS ("Energy Storage Systems") require access to the distribution system, which is facilitated through a DER interconnection application; the utility is obligated to enable and connect DERs under Section 6.2 of the DSC ("Distribution System Code") in a timely manner. Toronto Hydro is committed to providing and maintaining high quality customer service from end-to-end of the interconnection journey through the creation of a **Customer Connections Portal** to centralize all requests and provide a one-window seamless and consistent experience. Creating a single, accessible source for customers and staff alike provides the ability to offer reliable connection quotes in a timely manner.

As connection request volumes increase and the system becomes more saturated with DERs, Toronto Hydro expects that the complexity of these requests will similarly increase due to the need to balance current and future requirements of both existing and future DER owners. Eventually, the utility will begin to face limitations on its ability to cost-effectively accommodate new DERs in specific locations on the grid. Toronto Hydro believes that an important role for the utility in this emerging landscape will be to equip customers with easily accessible, accurate, and up-to-date information as to where in the service territory DERs can be accommodated most efficiently, and where it may not be possible or cost-effective to connect new DERs. To accomplish this, Toronto Hydro is committed to developing the capabilities required to display a **Hosting and Load Capacity Map** (or equivalent data portal) which will provide estimated available capacity for DER interconnection and load capacity at different locations on the network based on an automated hosting and load capacity analysis. Visualization of available capacity will provide a two-fold advantage to both the utility and its customers: the utility planners will be better informed to evaluate incoming applications and devise future system upgrade investments, and customers will be better informed to understand the cost complexity of current applications and strategize future DER project investments.

Toronto Hydro expects that the two initiatives above will only make large amounts of DER interconnections possible if data flow from the end-to-end journey is seamless and of high quality to aid grid operation and business decisions. To that end, the **Geospatial Information System (GIS) DER Asset Tracking** initiative will bind the DER visualization and interconnection process journey by streamlining the data management and flows across the different platforms associated with the journey to provide comprehensive records that unlock value in various business functions including DER-related product and service offerings and high-fidelity engineering, planning, and forecasting models.

Finally, in addition to streamlining processes and publishing hosting capacity data, Toronto Hydro will, where necessary, feasible and cost-effective, continue to invest in infrastructure and field technologies which can help alleviate DER connection constraints (i.e. hosting capacity constraints) on its grid. This includes the demand-driven **Generation Protection, Monitoring and Control** program (Exhibit 2B, Section E5.5), which involves installing monitoring and control technology at DER sites and exploring a range of additional options including bus-tie reactors at transmission stations to relieve short-circuit capacity constraints. This also includes a renewable-enabling focus for the utility's **Energy Storage Systems** segment (Exhibit 2B, Section E7.2.2), where battery storage systems will be installed on feeders where power quality and minimum load-to-generation ratios have exceeded 3:1.

In summary, the Facilitating DER Connections capability domain will be primarily addressed through the following initiatives, which are further summarized in Section D5.2.2.4:

1. Enhancing DER Connection Process
2. Hosting Capacity Map
3. GIS DER Asset Tracking
4. Generation Protection, Monitoring & Control (Exhibit 2B Section E5.5)
5. Renewable Enabling Battery Energy Storage Systems (Exhibit 2B Section E7.2)

D5.2.2.2 Leveraging DER Connections

The growth in grid-connected DERs comes with opportunities for utilities to leverage them for grid services and improved grid reliability and resiliency. Utilities across North America are building capabilities to utilize DERs to achieve benefits such as demand response. As the adoption of DERs continues to accelerate across Toronto, it brings opportunities for the utility to move from "walking" with DERs – by approving and enabling their connection – to "jogging" with DERs and unlocking further value in their ability to actively support reliable grid operation as qualified alternatives to traditional infrastructure investments.[13] In 2025-2029, Toronto Hydro plans to expand its use of distributed resources for demand response purposes (i.e. flexibility services) and expand its capabilities to monitor, control and dispatch DERs through a centralized platform.

Toronto Hydro has forecasted a number of capacity constraints emerging on a number of stations on the network in the short-to-medium term. The utility has previously explored LDR ("Local Demand Response") in the 2015-2019 rate period in the Cecil TS ("Transformer Station") area, and expanded this into the Manby TS and Horner TS areas in 2020-2024. The success set the stage for Toronto Hydro to build on LDR into a **Flexibility Services program**, to procure flexibility from customers and

[13] Adapted from Gridworks' Walk-Jog-Run Distribution Grid Planning Framework

aggregators to meet distribution system needs (for a comprehensive discussion of the Flexibility Services program, including accomplishments and enhancements in the 2020-2024 rate period, refer to Section E7.2.1). The program intends to leverage customer-owned flexible assets to provide the utility with new tools for managing and prioritizing capacity constraints that are present and will continue to emerge from the electrification and digitalization of various sectors and communities within this city. The program will also provide customers with new revenue mechanisms and opportunities to engage with their distribution company. Toronto Hydro expects this program will continue to grow and evolve in 2025-2029 as the utility accelerates its journey toward leveraging DERs in real-time and at scale, which will be necessary to navigate the energy transition effectively and efficiently for customers.

As discussed in the Facilitating DER Connections section above, Toronto Hydro also plans to continue deploying ESS in front of the meter, with a primary focus on leveraging ESS to alleviate certain real-time conditions that can prevent Toronto Hydro from connecting customer-owned DERs. Between the ESS and the Flexibility Services programs, the need for technology that can support adequate management of bi-directional distribution grid flows will be increasingly essential. Currently Toronto Hydro manually operates Toronto Hydro-owned DERs and manages them through vendor-specific platforms. As DER penetration increases, the utility's DERMS platform will require a **centralized dispatching and scheduling** module implemented to efficiently manage and operate the volume. Through this centralized platform, Toronto Hydro will be better equipped to plan future utility-owned ESS connections for peak shaving, and offer flexibility services with automated dispatch of demand response.

This capability domain will be primarily addressed through the key initiatives listed below, which are summarized in Section D5.2.2.4 and full details available in the Appendix.

1. Flexibility Services (Exhibit 2B Section E7.2)
2. Energy Center Enhancement for Leveraging DERs

D5.2.2.3 Monitoring and Forecasting

Once DERs are connected at high volumes, they can contribute to grid instability; operating the grid in real-time with larger volumes of DERs proves to be a greater challenge, coupled with fewer options to act when conditions suddenly change. Therefore, establishing the necessary monitoring and forecasting capabilities for DERs will be a crucial component of Toronto Hydro's Grid Readiness portfolio.

One of the largest initiatives that Toronto Hydro is undertaking which could significantly improve monitoring capabilities for DERs is the roll-out of **AMI 2.0**, which is discussed in detail in Section D5.3.1. AMI 2.0 is closely tied to both the Intelligent Grid and Grid Readiness portfolios as it allows the utility to monitor the behaviour of behind-the-meter technologies. Similarly, data that will be obtained through the GIS DER Asset Tracking, FLISR, AMI 2.0, and sensors initiatives will be integrated within the utility's **DERMS** platform to improve on the existing monitoring and forecasting modules available on the platform. Toronto Hydro envisions that the wealth of new data obtained will augment two core operational functions: state estimation and load and generation forecasts to identify and develop better planning decisions through conventional and Non-Wires Solutions methods and share information with IESO for more accurate information to create bulk supply and demand decisions.

Finally, to ensure Toronto Hydro is equipped with the intelligence necessary to plan long-term expansions of the grid and to engage in long-term procurements for flexibility services, the utility must continue to invest in accurate and geospatially granular long-term technology adoption and demand forecasts and scenarios. As discussed in Section 2B Exhibit D4.4.5, for its 2025-2029 investment planning cycle, Toronto Hydro invested in an Ontario-leading **FES ("Future Energy Scenarios")** model to project installed capacity for various technologies including DERs looking out to 2050 to better understand potential impacts on overall system demands. This initial modelling exercise provided net demand impacts at the level of station bus pairs. As a next step, Toronto Hydro intends to explore options for increasing the granularity of these scenarios, including by introducing feeder and/or supply-point (e.g. distribution transformer) impacts, which will provide the details necessary to plan increasingly targeted investments to support local DER integration and consumer electrification patterns.

The capability domain will be primarily addressed through the following initiatives, which are summarized in Section D5.2.2.4 and full details available in the Appendix:

- AMI 2.0
- Energy Centre Enhancements
- Low Voltage Level Forecasting

D5.2.2.4 Grid Readiness Program Summary

The Grid Readiness technologies introduced above are summarized in Table 3 below. For more detail on each technology, please refer to the Investment Program column. For each technology, more detail has been provided in the appendices of this strategy.

Table 3. Grid Readiness Program Summaries

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
Facilitating DER Connections	Enhancing DER Connection Process	Customer web portal to manage the end-to-end DER interconnection process. Portal will allow customers and/or contractors to review, submit, track, and if necessary cancel their DER interconnection applications in a single platform. Portal can also allow Toronto Hydro to semi-automate request handling and change orders for approvals and handovers between internal teams.	Toronto Hydro is expected to face non-linear growth in DER interconnection applications, which would contribute to overall evaluation and processing times. Current process methodology relies heavily on manual processes, including email-based communication and file sharing between employees and applicants, which will challenge Toronto Hydro's ability to deliver within its current lead times.	• Increased ability to handle application volume • Reduction in costs owing to labour hours attributed to manual data entry and tracking and processing applications; • Consolidated and transparent communication channels providing timely application updates to customers • Reduction in data entry errors and faster customer notifications if further or corrected data is required	$2M	IT/OT Systems (Exhibit 2B, Section E8.4)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
	Hosting and Load Capacity Map	Interactive web map and/or data portal enabling customers to view available DER hosting and load capacity prior to applying. Map will be built upon a hosting and load capacity analysis conducted on part or all of the distribution grid at the feeder level.	Toronto Hydro historically performs studies and analyses to identify the feasibility of DER interconnection requests on an application by application method, which is time-consuming and resource intensive. Rising volumes of applications will challenge Toronto Hydro's ability to deliver within its current lead times. Furthermore, the overall success rate and efficiency of DER connections can be improved by providing actionable information to prospective applicants.	• Increased visibility into the available capacity of the grid to host DERs • Integration with customer connections portal to update available capacity based on DERs awaiting install • Increased visibility of system nodes with immediate or near-term capacity constraints • Reduction in dependency on "general guidelines" within technical screens with insight into the required depth and analytical rigour to process applications	$1M	IT/OT Systems (Exhibit 2B, Section E8.4)
	GIS DER Asset Tracking	Streamlined data management and data flows across the different platforms associated with DER interconnection requests (connections portal, Geographic Information System ("GIS"), Energy Centre) to enhance visualization and control capabilities of DERs.	Toronto Hydro currently relies on manual data entry to transfer DER asset data records between platforms. This causes process inefficiencies and issues with data quality. Transferring GIS onto the Energy Centre backend requires manual routine updates which hinders Toronto Hydro's ability to develop more advanced applications of Non-Wire Solution program concepts. Generally, advanced smart grid capabilities are highly dependent on data quality and systems integration.	• Robust organization of DER interconnection data from application submission through to installation and commissioning • Reduce and/or eliminate poor quality or missing data from manual data entry between different platforms • Increased efficiency of data transfer through integration of data from DER platforms without the need for manual effort in syncing data	$1.5M	IT/OT Systems (Exhibit 2B, Section E8.4)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
	Grid Protection, Monitoring and Control	Installation of bus-tie reactors and exploration of other technologies to alleviate short circuit capacity constraints at select stations and Monitoring and Control Systems (MCS) for renewable DERs to prevent anti-islanding concerns and support system capability to connect and control distributed generation.	Toronto Hydro has identified and forecasted a number of stations with short circuit capacity limits, capping the amount of DER connections. Additionally, several feeder circuits have surpassed the recommended generation to minimum load ratio, increasing the amount of time required by inverters to respond to anti-islanding scenarios and decreasing the likelihood of inverters responding to anti-islanding scenarios.	• Remote and automated isolation of DER connections under specified conditions • Ensures operation of the distribution network within safe and allowable short circuit current limits • Avoids unintentional islanding and reducing the islanding risk of DER sources • Increased ability to observe large DERs in real-time to enable the maximum allowable amount of connected distributed generation	$35.0M	Grid Protection, Monitoring & Control (Exhibit 2B, Section E5.5)
	Renewable Enabling Energy Storage Systems (“ESS”)	Deployment of grid-side battery ESS with a primary focus on managing and alleviating constraints against connecting customer-owned renewable energy generation facilities. This can be accomplished by operating ESS as a load on feeders with high generation and low load demand. As a secondary matter, the utility will also continue to explore other grid supporting use cases for distributed, front-of-the-meter ESS.	Integration of renewable energy sources such as solar require a reliable and flexible solution to address the potential of grid instability and to enable integration of high levels of renewable energy.	• Increased peak load management • Improving overall power quality by resolving load-balancing on feeders with MLGR issues • Bolsters public policy objectives by encouraging DER uptake to reduce GHG emissions	$22.5M	Non-Wires Solutions Program (Exhibit 2B, Section E7.2)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
Leveraging DER Connections	Flexibility Services	Programmatic approach to address localized distribution issues through targeted procurement of demand response (i.e. peak shaving) services from owners of DERs and flexible loads.	Increased electrification will require Toronto Hydro to identify short-to-medium term capacity constraint-releasing methods alongside the more traditional "poles and wires" approach investment strategy.	• Improved reliability through demand congestion management • Deferred (or avoided) capital investments where demand is uncertain • Bolsters public policy objectives by encouraging DER uptake to reduce GHG emissions • Increased customer engagement and participation through revenue-based mechanisms	$5.7M (OPEX)	Non-Wires Solutions Program (Exhibit 2B, Section E7.2)
	Energy Centre Enhancement for Leveraging DERs	Implementation of the Advanced Scheduling and Dispatch module within Energy Centre (DERMS) to (i) enable real-time control and management between storage management systems and (ii) augment the Flexibility Services program.	Currently existing Toronto Hydro owned DER assets are manually operated and/or managed through vendor-specific platforms. This operational method will become unsustainable without a centralized dispatching and scheduling platform to optimize coordination of assets and participation in Flexibility Services programs.	• Enhanced integration of energy storage projects • Improved resource utilization of DERs • Improved coordination of DER dispatch and scheduling on one platform	$150K (OPEX)	IT/OT Systems (Exhibit 2B, Section E8.4)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
Monitoring & Forecasting DER Connections	AMI 2.0 for DER Monitoring	Deployment of next-generation smart meters in 2025-2029. These meters will provide new and enhanced forms of telemetry at the customer supply point, including data that will be relevant to monitoring and managing the impacts of DERs and electrified consumer technologies (e.g. EVs). Toronto Hydro will explore use cases from this data to inform the next phase of the DER monitoring and control strategy in 2030.	As DER penetration increases, the variability in household level voltage will require more fine-tuned DER monitoring and management to anticipate and address situations such as voltage violations and overloading.	• Improved observability of customer level loads and voltages • Increased capability of current and future flexibility service programs • Optimize DER dispatch to address grid conditions in local areas • Enhanced baseline data for use in developing long-term investment planning forecasts and other decision-making analytics	$248.1M (Total Revenue Meter replacement cost in 2025-2029)	Metering Program (Exhibit 2B, Section E5.4)
	Energy Centre Enhancement for Monitoring and Forecasting	The implementation of other Grid Modernization initiatives creates more powerful monitoring and forecasting capabilities within DERMS/Energy Centre to identify and act on any operational issues, deviations from expected performance, or potential grid constraints caused by DERs. Integration of more granular data into Energy Centre can build on DER disaggregation and day ahead local forecasting capabilities to broaden flexibility services and	DER penetration requires monitoring and forecasting capabilities to understand the impact the assets will have on the grid due to the bi-directional power flow introduced onto the network.	• Improved ability to coordinate with IESO (bulk supply and demand planning) • Improved load and generation forecasting abilities • Enhanced monitoring of DERs to identify possible voltage fluctuations • Increased visibility of DERs through disaggregation display (e.g. regions, area, transformers) for future Non-Wires Solutions program locations	$2.5M	IT/OT Systems (Exhibit 2B, Section E8.4)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
		energy storage programs as they develop.				

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
	Low Voltage Level Forecasting	Future Energy Scenarios (FES) provides an overview of possible future changes to power demand, energy consumption, generation, and storage across the City of Toronto with an assessment of their potential impacts on the distribution network. The scenarios are predicated upon a granular, consumer choice-based analysis of future loading conditions at the desired modelling level. In 2025-2029, Toronto Hydro will consider options for enhancing the geospatial granularity of this model to support targeted, local investment planning and various other value streams related to electrification and the energy transition. This will require incremental investment in modelling capacity.	Population growth and increased electrification to support the energy transition to Net Zero represents an increasing level of uncertainty due to the many different economic and policy conditions that can alter the anticipated level of electrification. A strategic framework and methodology are required to inform and support network planning and future infrastructure investments. While Toronto Hydro can presently model these factors at the station bus level, it is necessary to enhance the model granularity to provide better insight into how electrification and DERs could impact the system at the low-voltage level (i.e. feeder and neighbourhood level).	• Standardized strategic outlook of different drivers of change to support needs across different Toronto Hydro business functions as well as planning consultations with customers and stakeholders • Increased insight for planners into the potential geospatial distribution of electrification on the network and technologies representing the make-up • Optimized decision making for investment planning at the feeder level with real-time data from the system observability program to confirm and adjust future forecasting	Initiative will be funded as a Software Enhancement (Estimate TBD)	IT/OT Systems (Exhibit 2B, Section E8.4)

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D5.2.2.5 Grid Readiness Track Record

Over the last decade, Toronto Hydro has strived to be a leader in Ontario when it comes to exploring and implementing technologies and solutions for facilitating, leveraging, monitoring and forecasting DG and DERs more broadly. The following are some major highlights from recent years.

1. Electric Vehicle (“EV”) Smart Charging Pilot

Toronto Hydro partnered with Plug’n Drive and Elocity Technologies to trial an EV Smart Charging Pilot aimed at understanding EV charging patterns and behaviours in Toronto and gathering information to assist in the development of future EV programs to support current EV drivers and those wishing to switch over to an EV. Benefits of this pilot include supporting the development of additional tools for EV owners to monitor, schedule, and control their charging sessions, and collecting data and insights to understand impacts of EV charging on the distribution grid.

2. Non-Wires Solutions

Toronto Hydro has been a leader in the procurement of demand response services from customers. The utility’s Local Demand Response program (LDR) was the first utility-driven NWS program in Ontario and has been deployed successfully since the 2015-2019 rate period. This program was 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. In the 2015-2019 rate period, Toronto Hydro successfully used LDR to reduce summer peak demand at Cecil TS by about 8 MW, helping to avoid anticipated capital investment. In the 2020-2024 period, the utility has been pursuing similar DR services in the areas of Manby TS and Horner TS, and, through the OEB Grid Innovation Fund and Innovation Sandbox program, is working with the IESO, Power Advisory, and Toronto Metropolitan University’s Centre for Urban Energy to implement a Benefit Stacking Pilot, which will trial an auction mechanism to procure DR resources to provide local system service, and aggregate these resources to offer their capacity into the IESO wholesale market. In 2025-2029, Toronto Hydro is planning to expand its Local Demand Response program into a more diverse Flexibility Services program and procure up to 30 MW of demand response capacity in the Horseshoe North area. For more details on Toronto Hydro’s Non-Wires Solutions programs, refer to Section E7.2.

3. DER Integration

Toronto Hydro has a well-established program for DER facilitation and integration, and has been actively supporting DER connections for its residential, commercial, and industrial customers. As of the end of 2022, Toronto Hydro has 2,424 unique DER connections to its distribution grid with a total capacity of 304.9 MW. For more information on Toronto Hydro's experience with, and plans for, connecting and integrating DERs, please refer to Section E3 (Capability for Renewables), E5.1 (Customer Connections), and E5.5 (Grid Protection, Monitoring and Control).

4. BESS ("Battery Energy Storage Systems")

Toronto Hydro has been active in the energy storage space since 2017, with several existing projects completed or underway. The utility has learned a great deal with respect to procuring, designing, constructing, commissioning, and utilizing BESS over the last six years. The Bulwer project, a front-of-the-meter 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 behind-the-meter BESS projects, including one at the 500 Commissioners street facility, and two that are located on customer sites (i.e. Metrolinx ECLRT and TTC eBus garages). These projects have also provided valuable experience and have supported the development of various capabilities that will be valuable in deploying, facilitating, monitoring, forecasting, and leveraging BESS going forward. For more details on Toronto Hydro's experience with BESS and the strategy for 2025-2029, please refer to Section E7.2.

5. FES ("Future Energy Scenarios")

To support preparation of the 2025-2029 Distribution System Plan, and in recognition of the growing uncertainty with respect to future load growth and DER adoption rates, Toronto Hydro commissioned the province's first Future Energy Scenarios model and report to provide a detailed overview of possible future changes to power demand, energy consumption, generation and storage across Toronto and an assessment of their potential impacts on the electricity distribution network. This project was a major step forward in the utility's development of a more robust long-term strategic grid planning function and was essential to the adoption of a "least regrets" approach to capacity planning for the 2025-2029 period, which is discussed in detail in Section D4. Going forward, Toronto Hydro intends to explore opportunities to further enhance its demand forecasts and scenario analyses, including by investing in more granular geospatial models which can support improved capacity planning at the neighbourhood level in anticipation of long-term trends in the uptake of technologies such as EVs and heat pumps.

D5.2.2.6 Innovation Program

Progress across all domains of the *Grid Readiness* portfolio (and related elements of the broader Grid Modernization Strategy) will be supported in 2025-2029 by an **Innovation Program**, which will focus on designing and executing targeted innovation projects in collaboration with customers, stakeholders, and technology providers, with the objective of creating scalable and sustainable solutions to enduring or imminently anticipated problems with respect to widespread DER integration and electrification of the energy economy. A robust innovation program will help the utility allocate the funding necessary and create the organizational pathways required to address the novel challenges and opportunities that policy-supported DER proliferation and integration will present to the grid and utility operations over the next decade.

Learnings from all of the innovation pilots will be shared within the industry to foster industry-wide collaboration and reduce innovation risks. Where the pilot is successful, Toronto Hydro aims to scale the solution and roll it into existing business practices to provide rate payers benefits.

There are a number of innovation project concepts that Toronto Hydro is considering for the 2025-2029 rate period. Some examples of potential projects are listed below in Table 4, while full descriptions are in Section D5.3.8: Appendix I – Innovation Pilot Projects and Exhibit 1B, Tab 4, Schedule 2, Appendix A..

1 **Table 4. Sample Innovation Pilot Project Summaries**

Pilot Concept	Description	Need	Benefits
Flexible Connections	Explore and develop technological and commercial offerings that could allow customers to more cost-effectively connect distributed generation ("DG") on constrained parts of the grid. A "flexible" connection is one which could be controlled and curtailed in real-time by leveraging smart-grid technologies controlled by the utility. This could be achieved through development of an advanced Energy Centre (DERMS) system coupled with intelligent device installation utilized through a communications platform.	Integrating DG into the distribution network poses several technical constraints (e.g. voltage violations) if not proactively managed and coordinated. DG customers looking to connect on constrained parts of the network may be prevented from connecting, or could faced high costs and long lead times because of the need for system upgrades. Allowing Toronto Hydro to control the customer's DG output in automated coordination with critical system operating parameters could provide a more cost-effective solution in the future.	• Reduced delays and costs for customers looking to connect DG on parts of the grid approaching thermal and voltage limits • Increased customer engagement through new commercial arrangements • Optimized usage of existing network infrastructure • Improved overall hosting capacity for DERs
EV Commercial Fleet	Examining the impact of commercial EV fleet charging at depots and other charging segments and optimize charging schemes based on the flexibility requirements and preferences of Toronto Hydro and pilot participants.	Widespread adoption of commercial fleet electrification may face high connection costs, creating a barrier to EV adoption, as well as incurring significant distribution system upgrade costs if not managed in coordination with the utility.	• Quantify and minimize the impact of commercial fleet electrification on the grid • Quantify the total cost of ownership for smart scheduling and charging solutions for EV fleets • Identify necessary infrastructure to facilitate fleet transition to EVs

Pilot Concept	Description	Need	Benefits
Electric Vehicle Demand Response	Identify viable demand response models that facilitate coordinated charging and potential discharging of EV batteries to support network needs. An initial pilot project with some customers has been successful in demonstrating load shifting to off-peak times and load deferral by utility-initiated curtailment. Future projects will target a broader set of control technologies that enhance consumer choice and scalability over time.	The shift from combustion engine vehicles to electric poses several potential system challenges, such as overloading secondary distribution transformers, exerting additional electrical stress on overhead conductors and underground cables, and increasing peak load at various system levels. Together, these challenges can lead to distribution system instability; for instance, when a cluster of EV's on the same transformer charge simultaneously.	• Increased customer participation in new charging mechanisms • Deferred (or avoided) capital investment in station upgrades through smart EV charging management • Quantify EV charging impact on the secondary distribution grid
Advanced Microgrid	Identify viable microgrid topologies within Toronto Hydro's network and trial a microgrid on the distribution system to observe system resiliency in real-time grid conditions.	The increasing frequency of extreme weather events has the potential to cause widespread and extended power outages, which is a consideration for the imperative to electrify the city. This is a particular concern for population segments and services that rely on power for mission-critical needs.	• Quantify commercial viability of community microgrids to improve grid resiliency • Flexible resource to sustain operations during outages • Provide ancillary services to the wider grid • Facilitate new methods of connecting higher penetrations of renewable energy generation

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D5.2.3 Asset Analytics & Decision-Making

The *Asset Analytics & Decision-Making* portfolio within the Grid Modernization Strategy covers improvements that Toronto Hydro plans to make in order to more fully and sustainably leverage the value of existing and new forms of distribution system data and intelligence. Toronto Hydro possesses large quantities of data, including condition of its assets, the historical performance of its system, and electricity consumption. Through the investments planned within its Intelligent Grid and Grid Readiness portfolios, the utility foresees the accumulation of even more robust datasets over the next decade, including increasing volumes and varieties of real- or near-real-time network and asset conditions and performance data. At the same time, data analytics and automation solutions have emerged within the wider industry, which create opportunities for more effective delivery of traditional value streams for customers (e.g. reliability, safety, cost control) during the energy transition, while also enabling a more dynamic local energy market. This means that the availability of current, high-quality, and readily accessible data sets will graduate from a “nice to have” to “must have” for utility operations. Having the systems and expertise to support more detailed insights will become critical in the years ahead. Therefore, achieving the corresponding level of data quality and analytical rigour will require Toronto Hydro to continue investing in its people, processes, and digital tools.

The *Asset Analytics & Decision-Making* portfolio outlines the strategic focus areas for the advancement of Toronto Hydro’s digital asset management capabilities in 2025-2029. The utility’s objective is to accelerate progress on the foundational data analytics and decision-making capabilities that will be necessary to manage costs and operate effectively as changes in the energy sector accelerate beginning later this decade and into the 2030s. Toronto Hydro is focused on three main capability domains depicted in Figure 7 below.

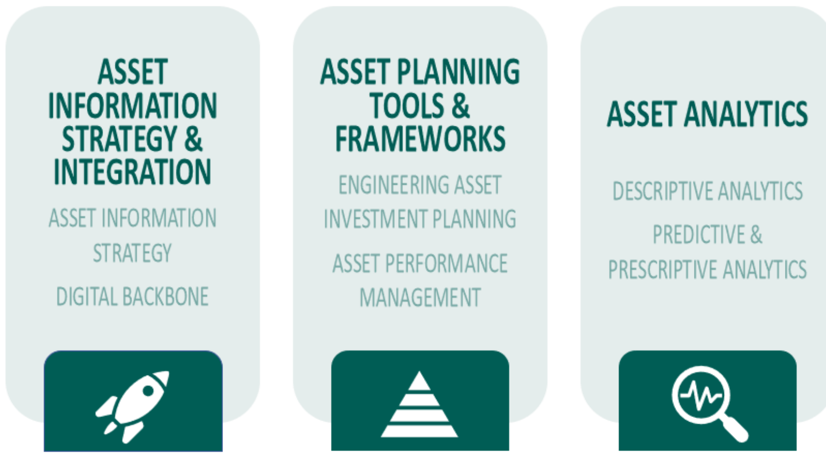


Figure 7: Major Components of the Asset Analytics & Decision-making Portfolio

These domains address the following investment needs:

1. **Asset Information Strategy & Integration:** This domain involves developing and documenting an Asset Information Strategy, and implementing a "digital backbone" that can support effective delivery and governance over the strategy and associated data standards. Activities in this domain will include identifying critical asset-related information and creating the processes and systems for storing and integrating it, as well as making the information readily available to business users.
2. **Asset Planning Tools & Frameworks:** This domain involves acquiring or enhancing the major software platforms and underlying decision-making frameworks that support Toronto Hydro's core Asset Management planning functions. These enhancements will be focused on further strengthening the alignment of specific capital and maintenance investment decisions with the utility's customer-focused investment plan and finding efficiencies within the planning process itself.
3. **Asset Analytics:** This domain focuses on developing new descriptive, predictive, and prescriptive analytical capabilities to drive efficiency and create value throughout the various stages of asset planning and operations.

The following sections provide additional detail on each of these domains. The activities and investments described throughout the Asset Analytics & Decision-Making portfolio will predominantly take the form of information technology projects, which are funded through either the IT/OT Systems Program (Exhibit 2B, Section E8.4) or the Information Technology OM&A program (Exhibit 4, Tab 2, Schedule 17). The incremental activities involved in embedding these solutions within evolving business processes, including implementation management, documentation, training, and administration, will require additional support from analysts, engineers, and various other professionals across the organization.

D5.2.3.1 Asset Information Strategy & Integration

The Asset Information Strategy & Integration domain involves developing and documenting an Asset Information Strategy, and implementing a "digital backbone" that can support effective delivery and governance over the strategy and associated data standards. Activities in this domain will include identifying critical asset-related information and creating the processes and systems for storing and integrating it, as well as making it readily available to business users.

As a key part of the effort to modernize the grid and grid operations, distribution utilities like Toronto Hydro will be gathering greater volumes and varieties of data in the next decade, with the intention of leveraging this data to develop value-adding applications and insights, as well as supporting automation of the grid (which in many cases is fundamentally a data-analytics-driven effort). The most important foundational step toward making this level of data-driven operations achievable and sustainable is ensuring that the process begins with a clear and comprehensive **Asset Information Strategy**. As part of its ISO55001 journey, documented in Exhibit 2B, Section D1, Toronto Hydro is currently in the process of creating a consolidated Asset Information Strategy, with the goal of having a clear asset data management strategy that identifies and prioritizes required asset information for current and future applications, outlines asset data quality requirements, assigns data ownership, retention levels, and backup requirements, and establishes change management processes. Toronto Hydro currently has multiple systems (such as GIS and ERP) which it uses for asset information purposes. The Asset Information Strategy and associated information standards will establish a system-agnostic guideline for all of the utility's key asset-related information and provide the basis for integration of relevant systems in order to create a "single source of truth" for critical data which will be stored as a central repository for analytics purposes.

The second foundational step is to proceed with further integration of relevant enterprise systems and additional data sources (such as images captured through maintenance activities) into a fully harmonized asset data registry, or "**digital backbone**" for asset planning and grid strategy. The digital backbone, in the context of this strategy, is the foundation of integrated data sources and systems, and storing those asset data effectively to enable more advancement in asset planning capability. Toronto Hydro has made gradual and targeted progress on this front in recent years, building on the implementation of new data warehousing and blending tools in 2017 to create purpose-built databases that bring asset and system information together for operational reporting and decision-making purposes. However, looking ahead at future demands for higher quality data and analytics, there are opportunities that the utility is aiming to pursue in 2025-2029 through the IT-OT Systems program (Section E8.4). One most significant opportunities involves enhancing asset data analytics by unifying data across major enterprise systems, including the utility's Geographical Information System ("GIS"), Enterprise Resource Planning ("ERP") system, and Customer Care & Billing ("CC&B") system. Fully and permanently consolidating relevant data in these systems is a significant investment, and there are a variety of possible approaches to achieving the desired end state. Toronto Hydro intends to explore and implement appropriate and cost-effective solutions for further integrating these major databases in 2025-2029, not only because these integrations will be increasingly necessary, but also because the utility anticipates substantial benefits to customers and stakeholders in the form of improved efficiency, analysis, and reporting. For example, high quality data on the condition of assets on the system can improve the timing and level of maintenance performed on those assets, leading to a lower failure risk and improved service for customers. The core features of a digital backbone are summarized in Figure 8 below.

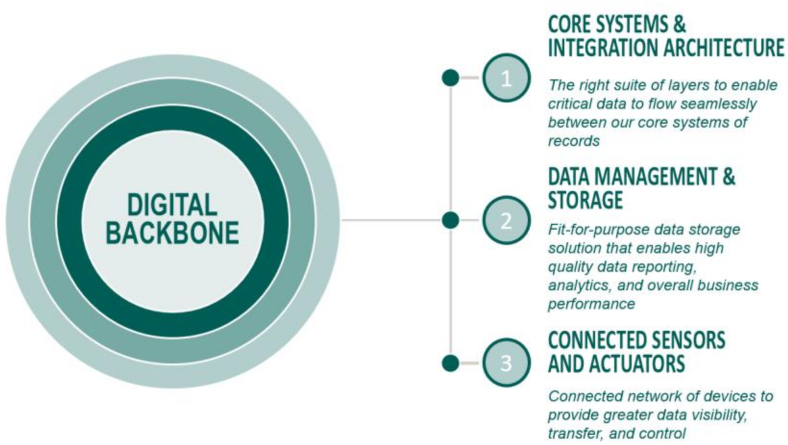


Figure 8: Core Components of a Digital Backbone[14]

[14] McKinsey & Company, Enhancing the Tech Backbone, n https://www.mckinsey.com/industries/industrials-and-electronics/our-insights/enhancing-the-tech-backbone

D5.2.3.2 Asset Planning Tools & Framework

The Asset Planning Tools & Framework domain involves enhancing the major software platforms and underlying decision-making frameworks that support Toronto Hydro's core Asset Management planning functions. These enhancements will be focused on further strengthening the alignment of specific capital and maintenance investment decisions with the utility's long-term, customer-focused investment plan and finding efficiencies within the planning process itself.

Toronto Hydro has been refining its risk-based asset management framework for many years, with the goal of being an industry leader when it comes to the use of risk inputs such as asset health scores to optimize operating and capital expenditure decisions. Having matured its asset management risk and outcomes frameworks in recent years, the utility has now begun to invest in digital platforms that will bring greater consistency, transparency, sophistication and efficiency to the implementation of these underlying decision-making frameworks within business planning processes. An overview of these future capabilities is summarized in Figure 9.

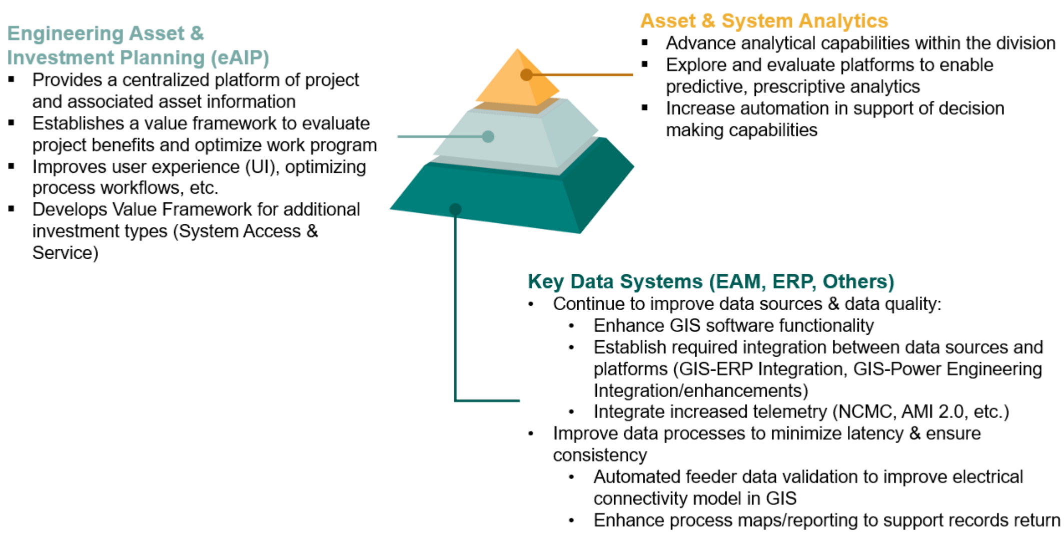


Figure 9: Asset Management Capabilities

As summarized in Section D1.2.1.1, a major element of this effort is the ongoing implementation of Copperleaf C55 as Toronto Hydro's new **Engineering Asset Investment Planning ("EAIP")** solution. At the heart of this tool is a custom value framework which assigns relative value to investments based on their likely contribution to Toronto Hydro's key performance outcomes, including their contributions to risk-based measures where applicable. This value framework will be leveraged to compare projects within and across programs and to produce value-optimized investment plan recommendations within prescribed funding and operational constraints, ensuring that Toronto Hydro's investment planning decisions are informed by data-driven assessments of costs and benefits in alignment with the utility's outcomes-oriented strategy.

Rather than relying on generic, "off the shelf" framework elements, Toronto Hydro is developing an industry-leading, fully customized value framework for its EAIP implementation, with the goal of ensuring that planners and management are confident in the outputs and recommendations from the tool. Given the customized nature of the implementation, it is an ongoing multi-year effort. Toronto Hydro is currently on track to begin leveraging EAIP's optimization capabilities for the majority of its system investment program by the beginning of the 2025-2029 rate period.

Following on the heels of the EAIP implementation, Toronto Hydro intends to explore and implement further extensions of its risk and value frameworks into other aspects of the decision-making cycle for its assets. For instance, upstream of EAIP is the initial process whereby planners are tasked with identifying suitable capital project candidates, which they then feed into the EAIP system for program management and optimization purposes. Toronto Hydro's goal in 2025-2029 is to extend the logic of its risk and value framework into this earlier step in the process by implementing an asset analytics tool which is capable of algorithmically generating recommended interventions on the system, which Toronto Hydro expects will support greater efficiency in planning by equipping planners with more effective decision-making intelligence. For example, planners will benefit from EAIP as it will reduce manual effort in determining optimized projects for each portfolio segment by an estimated 50 percent (pending implementation insights). This is further discussed in the Asset Analytics section below.

Toronto Hydro also intends to explore **Asset Performance Management ("APM")** applications in 2025-2029. An APM solution is a software tool (or set of tools) that can help an asset-intensive organization optimize the performance of its physical assets throughout their lifecycle by leveraging condition information – especially real-time condition information – to produce analytics that can inform more precise and accurate decision-making. Today, APMs are most commonly deployed by organizations such as manufacturers and power producers, where any production downtime can have a significant financial impact on the business, warranting investment in the creation of a "digital twin" of the plant (i.e. a high-resolution digital replica of the infrastructure) and the deployment of sensors and controls that capture detailed information that can then be leveraged by the analytics engine of the APM to predict and manage plant performance. Due to the highly distributed nature of Toronto Hydro's plant and the general absence of real-time asset condition information, there is not, at present, an obvious business case for implementing a full-scale APM. However, in recent years, Toronto Hydro has deployed real-time sensors in certain parts of the system (e.g. the Network Condition Monitoring and Control Program discussed above in section D5.2.1.4, as well as Exhibit 2B, Section E7.3) and intends to leverage these new telemetry points to explore and pilot the use of APM-like capabilities, with the goal of assessing whether there may be long-term value in these solutions.

In addition to the digital platform solutions discussed in this section, Toronto Hydro remains committed to continuously improving its foundational risk-based decision-making frameworks for its assets. For more details on these efforts, please refer to Section D1 and D3 of the Distribution System Plan.

D5.2.3.3 Asset Analytics

The Asset Analytics domain focuses on developing new, more advanced analytics capabilities to draw insight, drive efficiency and create value throughout the various stages of asset planning and operations. As mentioned in Section D1, Toronto Hydro has been ramping up its efforts to develop a more robust asset analytics function. This effort involves two major elements: (i) recruiting and developing engineers and analysts with progressive data analytics and coding skillsets, and (ii) investing in the information technologies necessary to support efficient and effective use of data for analytics and machine learning applications.

As in many other business sectors, the utility asset management space has become ripe for investment in innovative data analytics. This is due in part to two major factors:

1) The amount of data collected on the distribution system (e.g. condition, loading, and outages) and various correlated external conditions (e.g. weather patterns, consumer behaviours, and third-party geospatial data) has grown exponentially and will continue to do so as digitalization of the industry continues and the utility deploys more smart devices as part of its Grid Modernization Strategy; and

2) The development of advanced analytical tools, algorithms, and computing power and storage have made it easier and more cost-effective to analyze large volumes of data.

In the asset management space, utilities have the opportunity to leverage this data to create new kinds of analytics which could help identify and avoid inefficiencies, and lead to the discovery of opportunities to enhance the performance and value derived from distribution assets, with the eventual goal of having a network that can carry out automated decisions as depicted in Figure 10.

Asset analytics can be broken down into three categories which range in complexity:

(i) *Descriptive (and exploratory) analytics*, which relies on techniques such as data aggregation, data mining, and data visualization, to summarize historical data and provide a clear understanding of what has happened in the past;

(ii) *Predictive analytics*, which relies on techniques including regression analysis, time series analysis, and machine learning algorithms, uses historical data and statistical algorithms to make predictions about future events or trends; and

(iii) *Prescriptive analytics*, which includes techniques such as optimization, simulation, and decision analysis, to not only predict future outcomes but also recommend actions that can be taken to affect those outcomes.

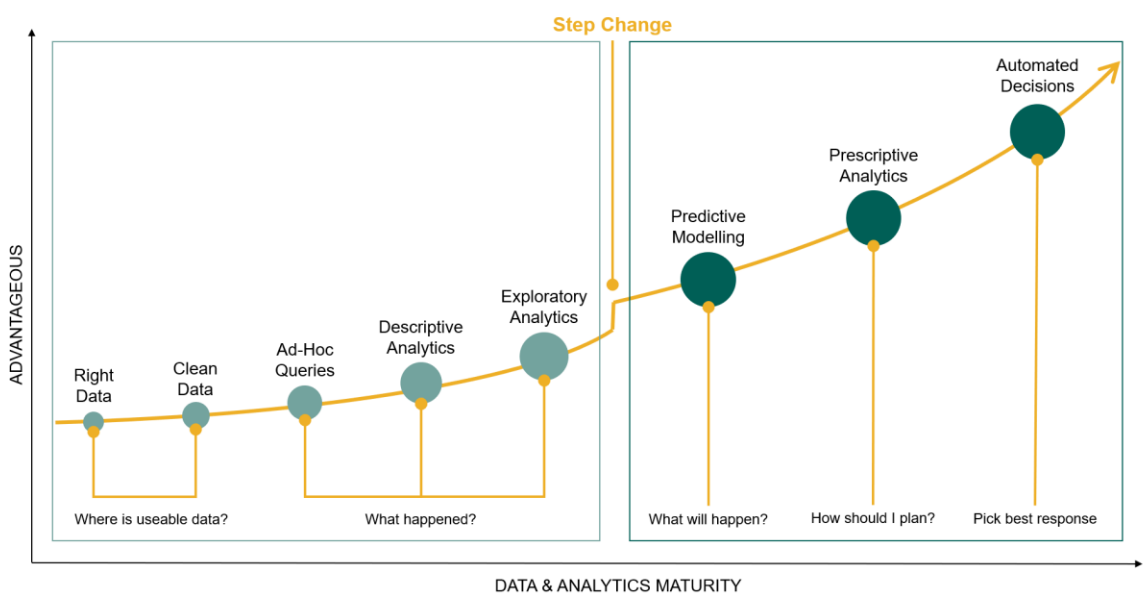


Figure 10 : Analytics Maturity Graph

Toronto Hydro has made strides on all three of these fronts in recent years and is planning to accelerate investment in these areas in the 2025-2029 rate period.

Descriptive Analytics: Since the procurement and implementation of more analytic platforms, such as data warehouse, data blending and visualization platforms in the 2015-2020 period, business units across the Toronto Hydro organization have steadily adopted these tools to enhance business processes and create an array of descriptive analytics. By moving beyond manual data workflows and the limited capabilities of basic visualization tools, Toronto Hydro has made many reporting and decision-making processes more efficient and effective, and this is especially true within the Asset Management parts of the organization. For example, Toronto Hydro leveraged a reporting technology solution to develop workflows in preparing data for analytics, relieving staff of manual data processing to focus on other value-added tasks. In the 2025-2029 rate period, Toronto Hydro's aim is to continue expanding the use of more sophisticated descriptive analytics, with a particular emphasis on investing in more effective geospatial visualization capabilities.

Predictive and Prescriptive Analytics: Toronto Hydro plans to accelerate the development and implementation of predictive and prescriptive analytics within asset management and grid operations in 2025-2029. The utility is prioritizing several initiatives, including the following:

- As mentioned in the Asset Planning Tools & Frameworks section above, Toronto Hydro is planning to implement an asset analytics engine which will leverage the utility's asset risk data, system topography, and other inputs to predict the future performance of the system with greater granularity and accuracy. The goal is for this analytics engine to also produce optimized recommendations for geographically defined capital projects based on their likely contribution to key value measures and system performance. This solution will complement the work program optimization capabilities within EAIP and complete Toronto Hydro's efforts to inject consistent predictive and prescriptive analytics into all stages of project planning. This will help to ensure the overall costs and benefits of the capital portfolio are optimized from the point of project conception to the point where projects are released for construction within the annual execution work program. Toronto Hydro also expects that these analytics will aid planners, analysts, and senior decision-makers in making planning decisions more efficiently by, for example, combining the functionality of three separate applications in one. Finally, the utility also expects an asset analytics engine to have regulatory benefits as it will support more efficient development of the long-term capital investment plan scenarios and associated risk and performance projections that are required for a five-year Distribution System Plan.

- In preparation for the 2025-2029 investment planning cycle and as a way of complementing the Stations Load Forecast process, Toronto Hydro introduced the Future Energy Scenarios model in 2022. This is a bottom-up, consumer choice model that produced projections under a variety of potential energy system transformation scenarios. Toronto Hydro's goal for the project was to enrich its long-term strategic planning capabilities and provide its stakeholders with an understanding of the way in which electricity demand, consumption and generation may change in the future and the range of uncertainty involved. Further information on Future Energy Scenarios can be found in Section D4. During the 2025-2029 rate period, Toronto Hydro plans to refine the model with new inputs, as well as develop a more granular level of forecasting to further enhance its investment planning process.

- Toronto Hydro is exploring opportunities to leverage analytics in predictive maintenance for its electric assets as well. For example, the utility is currently running a pilot project that will explore the use of high-resolution satellite imagery and artificial intelligence as a basis for creating a risk-based decision-support tool for the Vegetation Management program. Such a tool would be analogous to the asset-driven analytics engine discussed in the bullet above, insofar as it would leverage AI-driven predictive capabilities to forecast the system impacts of tree contacts at a granular level, while also leveraging predictive insights to recommend feeder-specific tree-trimming cycles and identifying high-risk areas that could benefit from spot trimming.

- More broadly, Toronto Hydro is aiming to take an agile approach in 2025-2029 to exploring and producing homegrown and vendor-supported analytics applications for targeted use cases. For example, the utility's in-house analytics teams have already developed demonstration models for electric vehicle detection leveraging AMI data, computer vision (e.g. using machine learning to identify and classify trip hazards from inspection photos), and data interpolation (e.g. predicting the likely cause of outages classified as "unknowns"). Toronto Hydro foresees numerous value-added use cases for machine learning models and advanced analytics, and plans to develop the resources and vendor partnerships in 2025-2029 that will allow for a more sustained approach to realizing these benefits for customers.

As discussed above and in Sections D1 and D3, Toronto Hydro has a steady track-record of leveraging its analytics tools to create efficiencies and drive innovation across various departments and functions, including most recently the development of models that demonstrate the potential for machine learning to assist in the identification of key trends such as EV adoption on the grid. The following are two additional highlights of the many analytics enhancements achieved in the last five years, specifically in the Maintenance Planning area.

1. Asset Deficiency Automated Prioritization Tool ("ADAPT")

Toronto Hydro has redesigned its priority decision framework through the introduction of ADAPT, a work request prioritization tool that uses an Alteryx workflow to use the deficiencies reported through inspection programs completed by contractors. The workflow takes in inspection reports and assigns priority and corrective actions using a job mapping devised by maintenance planning engineers.

a. Select benefits:

- Reduced manual engineering reviews of major assets by 40 percent
- Reduced errors from synchronization of inspection form and personnel changes
- Introduction of single notification that can bundle one or more deficiencies where appropriate, resulting in downstream operational efficiencies

2. Preventative Maintenance Units Tracking Workflow

Toronto Hydro introduced a new workflow centered around translating plant maintenance order statuses from ERP to maintenance unit attainments. This previously was completed through manual data processing and handling.

b. Select benefits:

- Reduced approximately 300 hours of labour per year
- Improved accuracy and consistency of data and data-sharing
- Provision of ad-hoc updates and more transparency in workflow changes when required

D5.3 Appendices

D5.3.1 Appendix A – AMI 2.0

1. Introduction and Role in Toronto Hydro's Grid Modernization:

Toronto Hydro was among the first utilities in Ontario to implement smart meters between 2006 and 2008 to support the efficient and effective operation of the distribution system. Primarily, these new meters improved on capabilities such as accuracy in customer billing, account connection/disconnection, and tampering detection. Rapid advancements in technology have made these first-generation meters outdated and obsolete. As the majority of these meters also reach end of useful life in the coming years, Toronto Hydro plans to replace them with next-generation smart meters – AMI 2.0.

AMI 2.0 goes beyond a billing device – the meters represent a network of sensors that provides previously unattainable visibility into performance and behaviour at the edge of the grid. They are equipped with improved hardware that supports data collection intervals up to every 5-15 minutes (and in some cases even more frequently). When this granular data collection is paired with higher bandwidth and shorter latency to improve transmission, the communication of meters expands system observability and can go further with other grid data to provide valuable insights into system operation, energy consumption patterns, and grid performance. AMI 2.0 has the potential to form a significant part of the digital backbone of the grid modernization strategy by improving the visibility and accuracy of data on voltage levels, power flows, and load consumption. These improvements are instrumental in painting a never-before-seen picture of the secondary network; along with sensors installed as part of the System Enhancement program, the utility will gain additional insights into the loading profiles of secondary transformers. Greater visibility means better analytics and decision-making for grid operations, asset management, and investment decisions at the secondary level.

However, fully realizing the modernization benefits that AMI 2.0 can provide is heavily predicated on investments in implementation and maintenance of the IT infrastructure beyond the physical meter, deployment of organizational capabilities such as advanced analytics and data governance/management, and alignment across multiple organizational stakeholders. Benefits realization in these categories will occur on independent timelines. Once the physical meter infrastructure is brought online, Toronto Hydro will undertake the specific IT projects required to set up system infrastructure to enable the use of AMI 2.0 insights for operations, asset management, and customer care.

2. Strategy for the upcoming rate period:

Approximately 70 percent of Toronto Hydro's residential and small commercial meters will have surpassed their expected useful life by 2025. Therefore, the utility intends to replace approximately 680,000 meters during the 2023-2028 period. As part of this replacement, the utility will introduce next generation smart meters and roll out the supporting network infrastructure.

3. Benefits:

The AMI 2.0 initiative brings about edge-computing network infrastructure and advanced capabilities to understand how electricity is generated and consumed in real-time. Some key advantages are listed below and summarized in Figure 11:

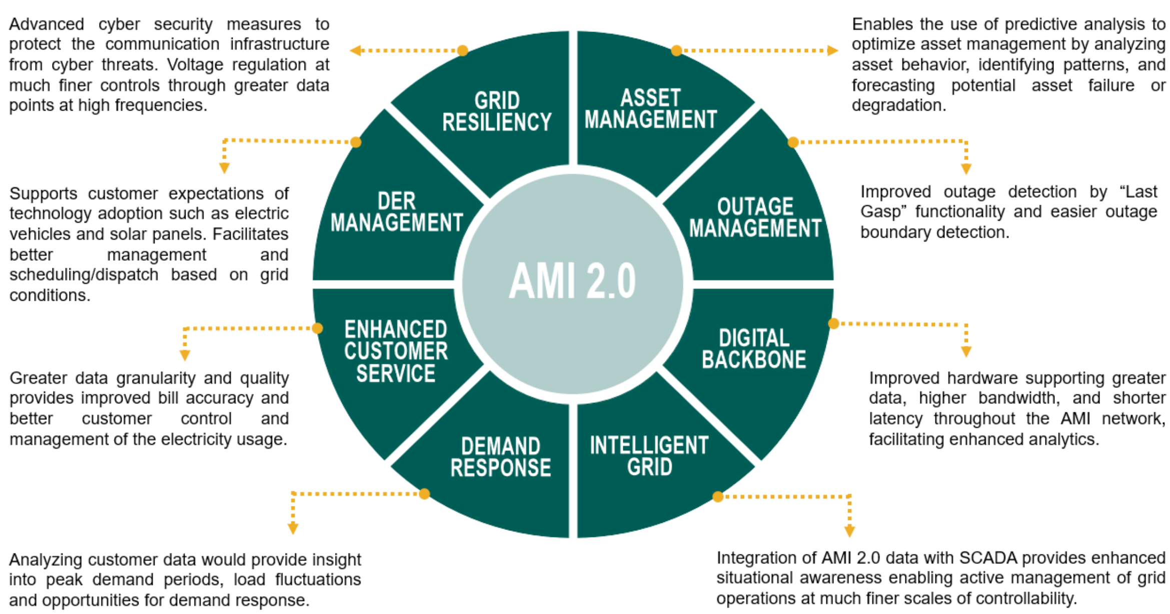


Figure 11: An Overview of AMI 2.0 Benefits

Improved visibility of the secondary network:

- Better investment planning can be realized by way of more granular data. The current FES model makes projections at the transformer station bus level, but with added visibility into the secondary network, the model could be expanded to the secondary transformer level.

This represents a step change in investment planning, as exhaustive geospatial projections provide planners better data for investment planning decisions.

- Better voltage regulation can be achieved by way of capturing voltage at many more points and at greater frequencies, allowing operators to regulate network voltage with much more control.
- Phase load balancing can be achieved by way of phase detection at endpoints of a circuit (the meter) – currently, crews are sent into the field to perform this measurement. Performing phase detection remotely, especially during storms, can reduce costs and improve grid reliability through real-time grid management.

Provision of last gasp functionality: AMI 2.0 meters enable automatic outage and restoration notifications ("last gasp") – currently, these notifications are required to be verified by phone or service call. Last-gasp meter alerts enable grid operators to identify outage locations and dispatch repair crews to more precise locations where they are needed, reducing costs and boosting the effectiveness of outage management operations. Meters also provide pinging capabilities, allowing the control room to monitor the status of outages and verify restoration quickly and accurately.

Improved understanding of customer-owned assets

- AMI 2.0 will provide insight into system voltages at the premise level, which is critical for determining when voltage violations from DERs and other assets are occurring and what actions may be necessary to mitigate such impacts. With more advanced DER monitoring and management, the utility could allow higher utilization factors for DERs as a result of greater confidence in DER management.
- Customers will be able to pair their meters with third-party software to provide a variety of services to control devices in their homes to manage their usage. This is particularly useful as a "plug'n'play" approach for future pilot projects that the utility may consider; with infrastructure already available, these pilots can be more feasible and cost-effective.

Scalability of infrastructure: AMI 2.0 can "future-proof" the meter as the ability to provide over-the-air updates will remove the risk of obsolescence of metering hardware over time. New capabilities of meters identified over time can also be rolled into new software and distributed over updates, providing flexibility to accommodate future technologies and customer expectations.

Enhanced data granularity and measurement

- The abundance of data provided by these meters will support development of analytical tools to expand on modernization capabilities such as predictive and prescriptive analytics, which will improve maintenance programs, asset management, and operational decision-making.
- Future integration with Energy Center will increase situational awareness and assist in curtailing/dispatching DERs for cases such as load management and reactive power management for voltage regulation.

4. Peer Success Stories:

For most utilities, the original business case for implementing AMI is generally focused around cost savings achieved from avoided truck rolls and the end of manual metering. Now that smart meters are becoming more commonplace in the industry, utilities are learning that the value of AMI goes beyond energy billing. These smart meters are representing a transformational shift in not only how utilities interact with their customers, but also how these meters serve as end-point sensors to obtain granular information about system operations and customer behaviour for data-driven decision making. Toronto Hydro has highlighted one of several peer success stories to give a sense of how utilities have achieved value from their AMI initiatives:

Peer Success Story	
Pacific Gas & Electric, California[15]	
Problem: PG&E relied on a limited number of research meters (~1,000) and SCADA data deployed at 60 percent of their substations to gather customer load information needed for distribution planning. The utility wanted a flexible way of aggregating load shapes for various configurations over different groupings of customers, which was not possible with their current method. Method: PG&E spent five years to develop the tools and processes (as well as transitioning to using AMI data as part of the utility planning process). Upon full transition, 4 million smart meters (representing 90	Selected Benefits: • Layered dashboard allowing operators and planners to visualize voltages from individual customer premise up to aggregated feeder level loads • Production of forecasts using hourly profiles for each circuit, customer class, and DER type • Improved peak planning from 24hours * 2days * 12 months = 576 data points to load shapes utilizing 8760 data points (number of hours in a year), representing a 15x increase in data • Development of 'Load Shape Viewer,' a tool that creates normalized load shapes with sensitivity

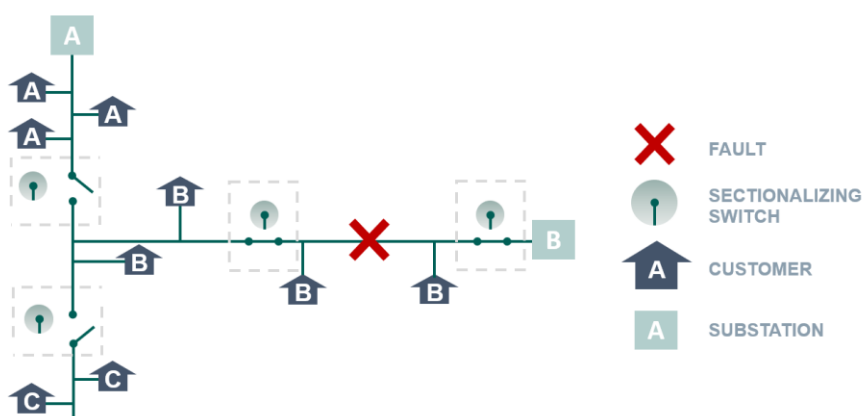
[15] U.S Department of Energy, Voices of Experience: Leveraging AMI Networks and Data, https://www.smartgrid.gov/files/documents/VOEAMI_2019.pdf

percent of their customers) were online with 99 percent accuracy, utilizing a 2-way 900 MHz RF mesh network.	from SCADA, weather, and temperature data input

D5.3.2 Appendix B – Fault Location, Isolation, & Service Restoration

1. Introduction and Role in Toronto Hydro's Grid Modernization:

Fault Location, Isolation, and Service Restoration (FLISR) technology represents a transformative approach to power outage management; it enables quicker detection, precise isolation, and automated restoration of power in the event of faults or disruptions. FLISR leverages advanced sensors, a communication network, and intelligent devices (like SCADA switches and reclosers) already present on the grid to automatically determine the location of a fault. Once the fault is located, the software uses remotely operable devices to rapidly reconfigure the flow of power so that some or all of the customers on a feeder can avoid experiencing an outage. As this requires the ability to isolate portions of the network and re-route power from other sources, it is critical that the system is configured with sufficient sectionalizing SCADA switches and feeders that are tied by multiple paths to a single or multiple substation(s).[16]



(1) Fault Occurs

[16] U.S Department of Energy, Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration, https://www.smartgrid.gov/files/documents/B5_draft_report-12-18-2014.pdf

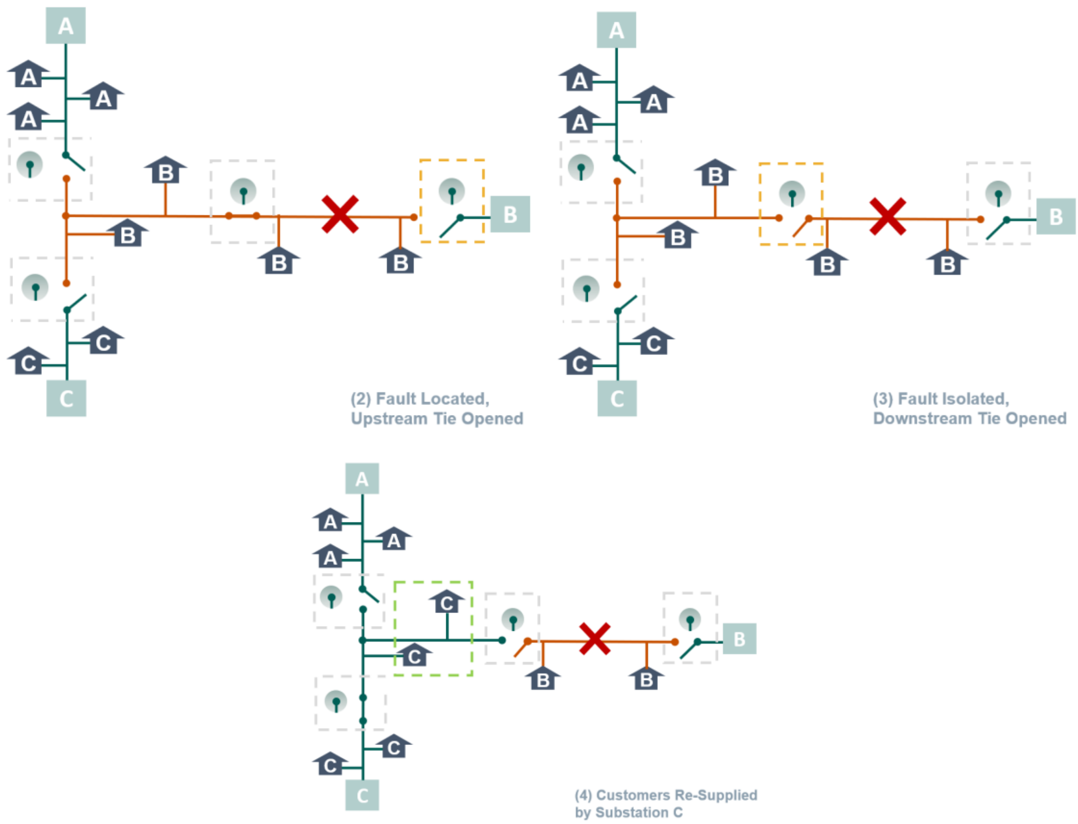


Figure 12: Schematic Overview of FLISR Operation in Four Stages

In Figure 12, (1) represents a fault scenario where the FLISR system locates the fault using sensors and reclosers that monitor flow of current. It then communicates the condition to other devices and/or the grid operators. Once the fault is located, FLISR opens the SCADA controlled switches from both sides of the fault, one immediately upstream closer to the source (2) and one downstream (3). At this stage the fault is isolated successfully. FLISR then closes the normally open SCADA controlled tie switch to reenergize the un-faulted part of the feeder (4). This process helps in minimizing the duration of outages which can be seen in Figure 13. In this illustrative scenario, FLISR automation is theoretically capable of reducing the restoration time from 45-75 minutes to 1-5 minutes.

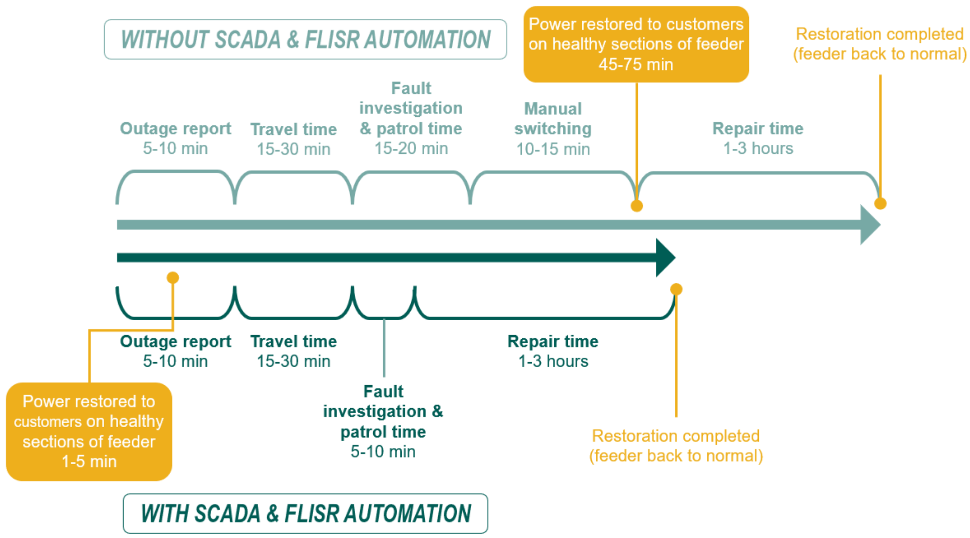


Figure 13: Typical timeline of Manual Restoration and FLISR

2. Toronto Hydro's Journey so far:

As FLISR utilizes information from a number of systems, it requires a substantive backbone of capabilities to successfully operate. Toronto Hydro is already set up with SCADA and Distribution Management System ("DMS") integration such that switches or feeders with faults are automatically displayed on the DMS. Fault status indicators were added to DMS in 2019, allowing controllers to more easily identify fault locations and determine which switches to operate in order to re-route power. And in 2020, voltage and current measurements were also added, as shown in Figure 14 below.

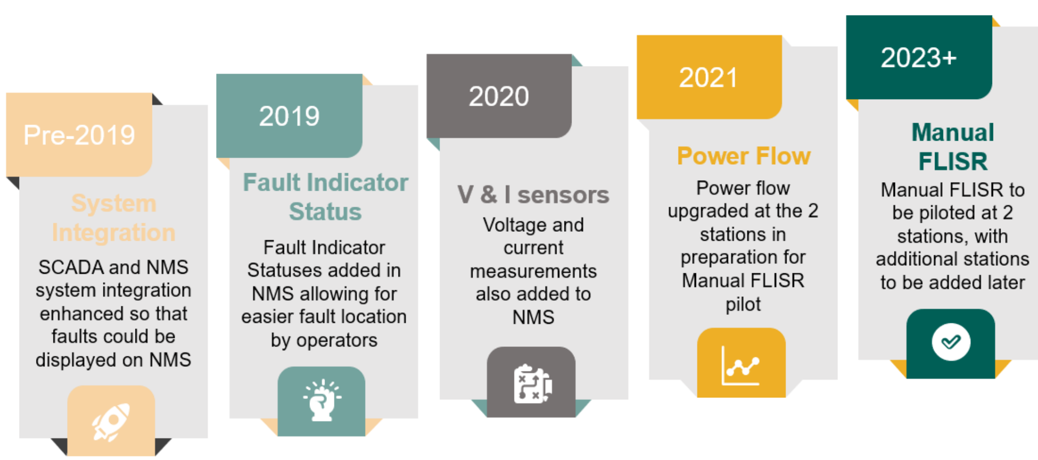


Figure 14: Timeline of FLISR Implementation

In 2021, a power flow upgrade was implemented which later enabled pilots at two stations (Finch and Bathurst) where manual FLISR started in 2023. The power flow upgrade is a data exercise that ensures accurate and high-quality data within Toronto Hydro's GIS and DMS systems. This data includes load from smart meters, conductor and other engineering attributes from CYME (Power Engineering Software), network topology and connectivity from GIS, as well as switch ratings. This integration will continue in the future as more monitoring and sensing devices are added to the system. Ultimately, having power flow is a more proactive way of operating the system versus switching blindly and risking reaching alarm limits. Power flow allows the utility to identify feeder capacities in real time, which in turn helps to identify the optimal switching procedure for the system. This is very powerful, especially in scenarios when feeders are close to overloading. It ensures operations do not have a negative impact on the system (i.e. moving load to a highly loaded feeder without this visibility). As more and more feeders reach their capacity due to growth on the system, this capability will become more important.

As part of its FLISR journey, Toronto Hydro is currently piloting manual FLISR at two stations (Finch and Bathurst), both of which are expected to be live prior to the 2025-2029 rate period. Manual operation is the first step in virtually every FLISR application as the fully automated FLISR solution typically requires extensive validation and calibration processes to ensure effective and reliable operations. This validation is done through manual validation of switching operations by control room operators. Operating the FLISR system manually and at a few stations at first will allow Toronto Hydro to evaluate the accuracy of the system's recommendations and assess how long it takes to come up with the solution. The learnings from the manual FLISR pilot will be used for change management when the system is fully rolled-out on the network. Prior to FLISR implementation, the "business-as-usual" procedure at Toronto Hydro consisted of the SCADA system notifying controllers of circuits that are experiencing faults. Controllers would then note down (on paper) which switches were seeing a fault. The circuits would then be identified in NMS and the procedure to restore power would then start. With manual FLISR, when an outage occurs, the system will determine its solution on how to sectionalize and restore power. The pilot will compare the "business as usual" procedure with the FLISR recommended procedure. This will help the project to continue to iterate until an optimal solution is reached.

3. Strategy for 2025-2029 rate period:

Over the next two years, Toronto Hydro will continue refining its data and network model. As this is carried out at pre-determined stations around the network, manual FLISR will be enabled. During the period between 2025 and 2028, manual FLISR will be tested at these target locations by the control room operators. The current criteria to move from manual to automatic FLISR at a station is for the manual system to see at least 20 faults of different types. Essentially, the safe transition from manual to automatic FLISR is contingent on a station seeing a certain number and diversity of outages, which is outside of the utility's control. However, as the utility begins piloting the system at the two initial stations, this requirement could change as more information about the operation of manual FLISR is gathered on Toronto Hydro's network. Additionally, planned ADMS upgrades during the 2025-2029 rate period are also necessary for auto FLISR enablement. Given these considerations Toronto Hydro's goal is that by 2030, stations in the Horseshoe area of the system should all be prepared for transition to fully-automatic FLISR.

4. Benefits:

Some of the major benefits of implementing FLISR technology are listed below:

- **Improved Reliability**: FLISR technology will enhance grid reliability by quickly detecting and isolating faults, minimizing the number of affected customers and reducing outage durations.
- **Improved Resilience**: With FLISR in place, the grid will become more resilient and adaptable to faults and disruptions. The ability to automatically detect, isolate and restore power enables the grid to self-heal and minimize the impact of incidents thereby improving overall grid resilience.
- **Minimized Customer Impact:** FLISR will minimize the duration of outage as well as the number of customers affected. This will result in reduced economic losses for customers and businesses.
- **Proactive Maintenance:** The FLISR technology and associated intelligent devices will provide valuable historic fault data which can be utilized to identify areas of concern and proactively addressing potential issues. By identifying fault patterns and identifying areas prone to recurring issues, informed decisions can be made about asset management.

D5.3.3 Appendix C – Enhanced DER Connection Process

1. Introduction and Role in Toronto Hydro's Grid Modernization:

The DER interconnection process is centered around two core steps: (1) the customer or installer provides the technical specifications about the planned system; and (2) the utility evaluates the impacts to the grid and then either approves the application or communicates any necessary changes. However, obtaining the necessary information and keeping all parties up to date on the application status can be challenging— especially for utilities where the number of interconnection requests are growing.[17] As the adoption of DERs continues to accelerate across Toronto, it is likely that the city will see an increasing installed capacity base of DERs over the 2025-2029 rate period**Error! Reference source not found.**. In light of this, Toronto Hydro is committed to supporting t he energy transition by connecting DERs to the distribution system in alignment with the Distribution System Code and in coordination with Hydro One and the IESO.

One of the primary challenges faced by Toronto Hydro due to the rising number of DER interconnections requests is the substantial amount of resources needed to evaluate and process applications. At present, Toronto Hydro's application processing methodology relies heavily on manual processes, including email-based communication and file sharing between employees and applicants. This approach results in a resource-intensive and time-consuming procedure; with a rising volume of requests, the utility's current approach will challenge the ability to process applications within current lead time.

Increasingly, utilities across the world are using tools such as web portals to manage interconnection process and keep the customer informed about the end-to-end process. In its commitment to embrace an accessible, transparent, and customer-centric energy system, Toronto Hydro plans to develop a user-friendly customer portal to simplify the connection process and provide greater transparency for customers' DER integration journeys. This portal will enable customers to seamlessly review, submit, track (and if necessary cancel) their DER interconnection applications in a single, accessible source. On Toronto Hydro's end, there is potential to integrate semi-automated request handling and change orders, enabling seamless approvals and handovers between internal teams.

The shift towards a streamlined, digital connection process not only reduces administrative burden and manual data entry effort, but also fosters a more inclusive approach – one that reduces barriers to widespread DER adoption. The portal will also facilitate DER data collection in a centralized repository which in turn gives Toronto Hydro new analyses capabilities to identify DER trends,

[17] U.S Department of Energy, Voices of Experience (VOE), https://www.smartgrid.gov/voices_of_experience#:~:text=The%20Voices%20of%20Experience%20(VOE,and%20testing%20the%20emerging%20technology

impacts, and usage patterns for continuous grid operations improvement. The advanced functionality from a customer portal positions Toronto Hydro as a utility that is ready to embrace automation and handle the anticipated increase in DER connections. Through this initiative, Toronto Hydro is setting the stage for a more streamlined, data-driven, and efficient approach to DER integration – benefiting both the utility and its customers.

Peer Success Story	
PEPCO – Integrating Work Management[18]	
Problem: Noticed an increase in incoming calls and employees were spending more time helping customers understand the interconnection application process and finding missing information. Method: Embarked on a journey to develop an online portal in 2012 to allow customers to input their applications and help PEPCO manage workflow, data tracking, and regulatory reporting with a go-live in 2016. Portal development focused on splitting the application process into two steps and reorganizing staff around the steps: one team helps the customer and contractor with application journey from receival through approval to install; another team works with the customer journey from system build through authorization to operate.	Selected Benefits: • Intuitive and interactive application process guides customers step-by-step • Provides data validation, reducing application errors and missing information • Allows customers to monitor their application's status in near real-time through a personalized dashboard • New online contractor account includes the ability to designate access to multiple users • Quickly moves the application to the next step in the process • Ability to see aggregated reports for all pending applications submitted online by contractor • Online signature feature eliminates the need for physical signatures • Upload attachments online—no need to email or mail supporting documents

2. Benefits:

Toronto Hydro recognizes there is a wealth of opportunity in improving its current connections process methodology that relies heavily on manual processes through the use of emails and file sharing. Customers using Toronto Hydro's current system sometimes have concerns about DER applications and who to reach out to on the status and lead times for their applications. A streamlined, semi-automated customer connections portal can provide Toronto Hydro with the following benefits:

- Reduced delays and costs owing to reduction in manual data entry and labour hours in tracking and processing applications

[18] *Supra* Note 17

- Consolidated and transparent communication channels providing timely application updates to customers
- Reduction in data entry errors and quicker customer notifications if further or corrected data is required

These enhancements will be necessary to ensure the utility can continue to provide high-quality customer service and meet connections application performance targets in the face of potentially higher rates of DER adoption over 2025-2029 and beyond.

D5.3.4 Appendix D – Hosting and Load Capacity Map

1. Introduction and Role in Toronto Hydro's Grid Modernization:

Determining the DER capacity that the distribution system can accommodate is often a challenge, and without proper planning and integration, DERs and incremental loads may adversely impact system stability and hinder maximum benefits utilization. Toronto Hydro performs ad hoc studies and analysis to identify the feasibility of DER connection requests, which is a time-consuming process.

Hosting capacity analysis (HCA) has emerged as a valuable option preferred by several utilities across the world. It enables the assessment of available capacity for new DERs without the need for costly and time-consuming studies. In particular, it can illustrate the preliminary capacity of DERs that the power system can accommodate at a given point of interconnection without exacerbating grid parameters such as short circuit current. An effective HCA can assist Toronto Hydro in making informed decisions regarding strategic grid investments to reduce future barriers to DER integration. Additionally, it can boost efficiency and transparency of the DER planning and interconnection process to accommodate the increasing volume of DER connection requests.

This initiative complements the customer connections portal as the HCA can be used to generate a user-friendly hosting capacity map, such as the sample depicted in Figure 15 below, that provides preliminary geographical insights into the available interconnection capacity within Toronto Hydro's distribution system. The HCA map can be embedded or sit alongside the connections portal, enabling customers to guide the scope of their application prior to submission. The HCA map supports a customer-centric energy system, providing greater upfront visibility in potential application complexities and guiding customer investment strategy for future DER projects.

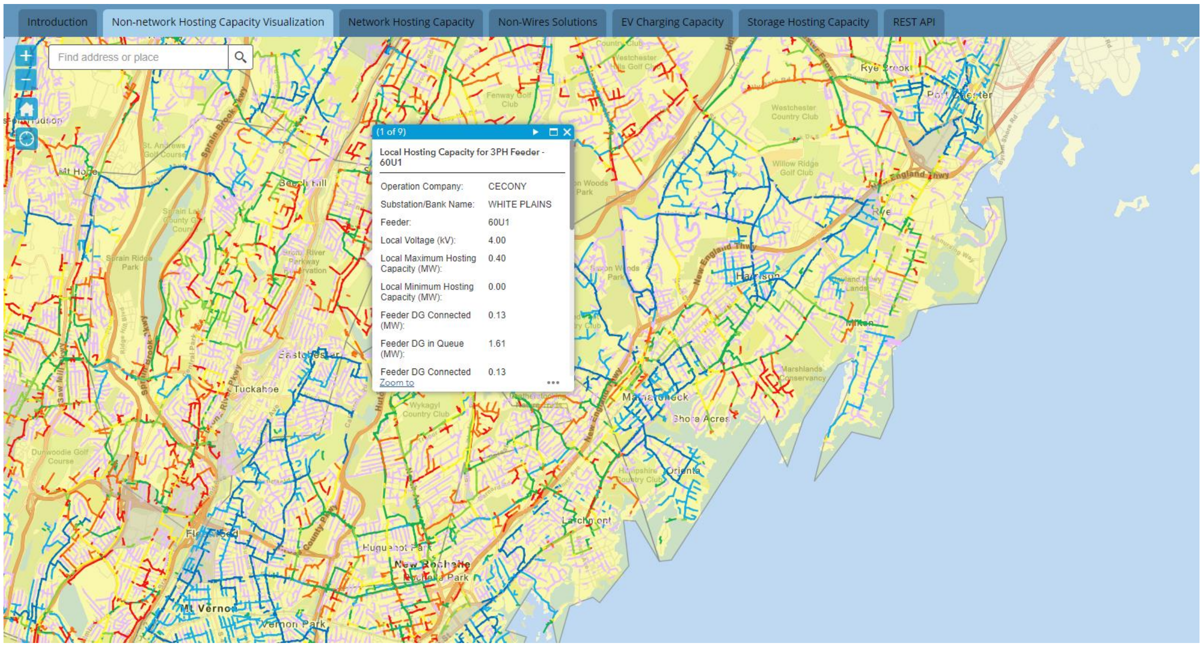


Figure 15: HCA Map Example – Consolidate Edison New York

Over the 2025-2029 rate period, Toronto Hydro intends to explore, develop and implement a Hosting Capacity Analysis and associated presentment tools. As part of this initiative, the utility will explore opportunities to calculate and present complimentary analyses, including load capacity constraints. Developing a hosting and load capacity analysis and presentment solution is a significant multi-year undertaking, as it will require upgrades to data quality and availability, the automated integration of various data systems, the development and implementation of complex, automated system analysis, and the procurement and implementation of a customer-facing geospatial visualization tool.

Peer Success Story

Hawaiian Electric Company (HECO) – Performing Daily Updates

Problem:

HECO originally looked at circuit penetration using the 15%-of peak rule, then transitioned to 50% of daytime minimum load and slowly rose up to 250% as more information and technologies became available to mitigate concerns; however, HECO determined that different feeder characteristics and infrastructure impact how much DER a circuit can handle.

Method:

HECO built a circuit model in “Synergi” (i.e. an asset simulation and optimization software) that feeds into their in-house hosting capacity tool. The tool runs an analysis of all primary circuits (from the substation to the transformer) and includes any PV systems (even if that system has not yet been installed). Location maps are created by running the analysis annually and ad-hoc. The tool provides an allowable amount of PV that can be easily interconnected for the entirety of the circuit.

Maps are updated daily based on new applications that are approved, which means that subsequent new installations looking to apply are evaluated against the capacity threshold for that circuit. If the installation size exceeds the hosting capacity limit, the application is sent for a supplemental review to specifically verify the location and how it would impact the circuit.

HECO separately reviews other conditions such as voltage rise/drop using a spreadsheet model to evaluate impact on the secondary network. This is especially important in sunny Hawaii where most DER installations are PV because the secondary side can experience voltage violations since most PV customers tend to generate maximum output at the same time (typically midday) rather than at various times throughout the day.

2. Benefits:

Some major benefits of implementing a Hosting Capacity Map for Toronto Hydro's service area are as follows:

- Increased visibility into the available capacity of the grid to host DERs to identify suitable locations for installations
- Integration with a future customer connections portal to update available capacity based on approved (but not yet installed) DER applications
- Increased visibility of system nodes with immediate or near-term capacity constraints to inform system upgrade planning to increase long-term hosting capacity
- Reduction in rule of thumb technical screens with introduction of granular analysis for the entire distribution system with regular updates

D5.3.5 Appendix F – GIS DER Asset Tracking

1. Introduction and Role in Toronto Hydro's Grid Modernization:

A forecasted increase in DER interconnections requests means that current data management practices that Toronto Hydro employs will no longer suffice without generating considerable administrative burdens and compromising data quality. Currently data from DER assets is manually entered, which is time consuming and prone to incomplete/incorrect data transfer. Toronto Hydro recognizes that automation will be a necessary core function at the heart of its data management methodology across difference processes associated with DER interconnection requests. While the customer connections portal initiative is a step towards automation by allowing DER asset data to be automatically recorded once an application is submitted and then approved, it lacks capability to visualize geographical and electrical connections to the distribution system.

Hence, a new tool that has emerged within the industry to bridge this gap is the concept of GIS DER Asset Tracking. The initiative explores the process and tools to streamline and standardize DER asset data in Toronto Hydro's GIS system. It aims to identify key asset information and connectivity data as well as integration requirements within GIS such that Toronto Hydro's record keeping procedure is streamlined and thorough. Apart from data quality and management, another key functionality of DER Asset Tracking which will be touched upon in the Monitoring & Forecasting activity is real-time monitoring and control of DERs. Currently DERMS is connected to Toronto Hydro's SCADA system to read real-time data; however, its System Map and DER one-line diagrams are not connected to GIS data in real-time – meaning that changes in physical location and configurations are updated on a monthly frequency requiring routine updates of the GIS extract file from GIS software onto the DERMS backend. As the number of DER assets continue to increase, a set frequency methodology will no longer fit Toronto Hydro's control toolbox in order to establish future extensions of programs related to demand response, market prices, voltage fluctuations and more.

As Toronto Hydro embarks on its mission to become a utility of the future, integration of DER asset information in GIS systems for monitoring and control purposes will be crucial to encourage and accommodate new DER connections. GIS DER Asset Tracking rounds off the other two *Facilitating DER Connection* initiatives as it links together the seamless flow of data from end-to-end of the connections journey and provides the right kind of data required to refresh a hosting capacity analysis with the least amount of manual intervention needed. The three initiatives work together to give confidence that Toronto Hydro understands on a granular level where current DER assets sit on the system and where future ones can be anticipated and accommodated in a timely manner.

2. Benefits:

Toronto Hydro recognizes that streamlining the data management process associated with DER connections requests comes with a wealth of benefits. Some major benefits of implementing GIS DER Asset Tracking is as follows:

- Robust organization of DER interconnection data from application submission through to installation and commissioning through industry-leading data management practices

- Reduce and/or eliminate poor quality or missing data from manual data entry between different platforms
- Increased efficiency of data transfer through integration of data from systems such as the proposed customer connections portal, GIS, and Energy Centre without the need for manual effort in syncing data across platforms

D5.3.6 Appendix G – Energy Center Enhancements

1. Introduction and Role in Toronto Hydro's Grid Modernization:

Distributed Energy Resource Management System (DERMS) is a powerful software tool which can be used to integrate, aggregate, monitor and control DERs located in front or behind the meter in real-time. As deployment of these assets such as solar panel and battery energy storage systems continues to expand, utilities face the challenge of preparing for a well-coordinated integration of DERs on grids that were historically designed for predictable, one-way energy flows.

From an operational perspective, this includes proper management, control, and operational oversight given the variability in DER output to prevent issues such as high voltages during peak hours, abnormally low voltage during load recovery periods, and intermittent voltage fluctuations. From an ownership and operation perspective, the delineation of who owns and manages DER assets also lends uncertainty in how to achieve optimal grid management; key considerations include the majority of DER growth comes from assets not owned by the utility, immature technology can complicate interoperability, the number and distribution of DER endpoints can challenge the scalability of utility-driven solutions, and dispatch of DER assets may not necessarily align with stakeholder values (e.g. a third-party owned DER may be dispatched to reduce an electric bill which may not be aligned with the utility operator at that point in time).

The introduction of a DERMS serves as a vital step in consolidating the visibility of DERs across the grid, and it lays the groundwork for exploring third-party involvement and partnerships in DER and DERMS ownership and control as the complexity of ownership models and interoperability increases in a maturing technology space.

Most DERM systems have the capability to exchange data and control with other enterprise supervisory control systems such as control systems with the ADMS platform. DERMS also serves as the system of record for all DER related data, and provides operators visibility to the parts of the grid not visible to the ADMS. DERMS comprise of the following core functions:

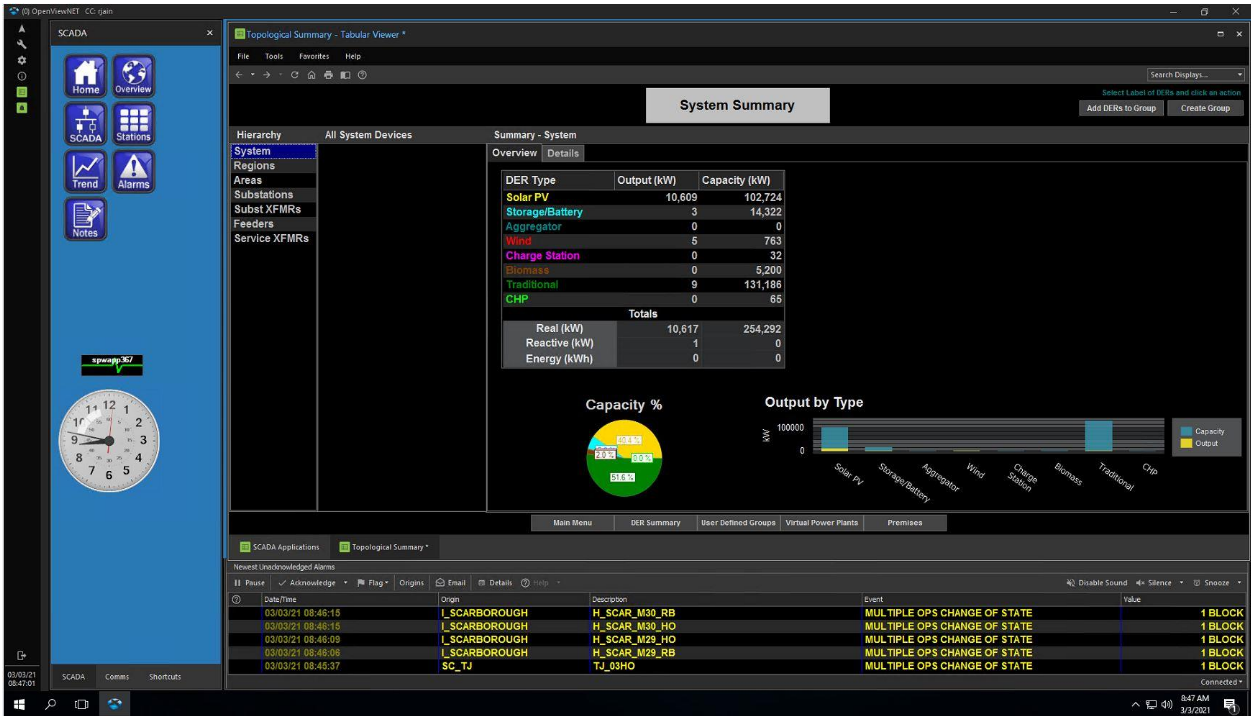
- **Aggregate**: DERMS take the services of multiple DERs and present it as an aggregated smaller group of more manageable virtual resources that are aligned with grid configuration.
- **Translate**: DERMS can extract a variety of data from different DERs that may use various communication protocols and present it to the upstream controller in a streamlined view.

- **Simplify**: DERMS has the capability to provide simplified services that are useful to distribution operations, which are power-system centric as opposed to DER centric.
- **Optimize**: DERMS can provide requested services by coordinating functions depending on location and circumstance.

Toronto Hydro incorporated DERMS in 2019 in the form of its Energy Center. Phase 1 of system implementation focused on real time monitoring of DERs; in its current state, the Energy Center provides visibility to approximately 2,200 DERs connected to the system, including three utility-owned battery energy storage systems. Currently DER control capabilities are unavailable, although utility-owned DER sites can be controlled via SCADA on vendor specific platforms. With almost four years of experience in operating the Energy Center, there is now a need to explore expansions to it.

2. Current Energy Center Modules – Monitoring and Forecasting:

Energy Center facilitates real time monitoring of DERs through visualization of the complete portfolio of DERs to provide up-to-date information on the status, performance, and health of DER assets. This data is used to assist in promptly identifying any operational issues or deviations from expected performance. The data can also be parsed by DER type, as well as a hierarchical outlook across the system, regions, terminal stations, and municipal stations, which is particularly useful to gain perspective of DER distributions across the system by type to assist with grid planning. Individual DER monitoring, as shown in Figure 16, expands on details such as one-line diagrams, alarms, generation/consumption, and charging/discharging, which is useful for operators to identify potential issues such as voltage fluctuation and SOC battery issues. Overall, a consolidated view of DER asset performance makes it easier and quicker for decision-making.



1 **Figure 16: Energy Center Overview Screen**

2 The second function currently available in Energy Center is a forecasting tool that enables Toronto Hydro to create accurate load and renewable generation forecasts for periods ranging from 1 – 35 days. These forecasts use the historical archive of area load, renewable generation and weather data, and a variety of user-selected algorithms/models to generate load demand and renewable generation outlooks for the selected period. These forecasts enable the utility to anticipate fluctuation in generation and consumption patterns of DERs and accordingly plan for contingency actions. In current operations, Toronto Hydro uses load forecasting at two stations to carry out LDR programs by way of battery dispatch scheduling to achieve peak shaving.

3. Building on Monitoring and Forecasting:

As Toronto Hydro continues to evaluate and connect more DER assets, generating insights and value derivation from these assets becomes limited without access to quality, structured data. While the current implementation of the Energy Center allows the utility to see direct information about their DER assets on one platform, understanding how DER operation and coordination will affect the grid down to the feeder level is not yet possible due to lack of visibility. Similarly, asset data related to DERs are not yet streamlined and are updated manually on a set frequency, which means that synchronizing data into the Energy Center for new assets occurs in a piecemeal approach with room for data error.

This is where the integration of technologies mentioned throughout the Grid Modernization strategy will play a role in augmenting the monitoring and forecasting capabilities of the Energy Center. System observability enhancements such as AMI 2.0 and sensor installations will provide more granular customer consumption data and patterns as well as visibility into feeder loading conditions and power flows. This coupled with the roll-out of FLISR enables automated fault management, removing the human element of complex decision-making in real-time. In such an environment, the Energy Center can now play a new role – if the grid is now able to more intelligently identify and minimize feeders off-supply, data integration and communication with the Energy Center now means that utility-managed DER assets are able to play a role in restoring or stabilizing other parts of the grid through fault and post fault events. Greater visibility of the grid at the low-voltage level also opens up the ability to run more granular forecasts in the Energy Center to develop operational plans. This can be used at multiple stations beyond the two currently used for LDR and provide data to support targeted expansion of the program. Furthermore, forecasting scenarios that factor in geospatial distribution of DER assets and their implications on the capacity of the system at target points on the network will become an essential tool in the utility's investment planning process, deferring or avoiding capital expenditure where it makes sense. Finally, the implementation of GIS DER Asset Tracking ensures that the organization has confidence in data available in the Energy Center and has the added ability of running forecasts ahead of time for asset applications that have been accepted but not yet connected to understand implications, if any, before the DER is switched on.

4. Future Modules - Scheduling and Dispatch Module:

Currently, Toronto Hydro is unable to efficiently schedule, aggregate, and optimize a set of utility-owned DER assets. Instead, existing DER assets are manually operated and/or managed through vendor-specific platforms. Specifically, the control and management of utility-owned DERs is complicated due to the increased training, management, and licensing requirements for multiple platforms and the lack of control of all sites from a single, centralized location. There is a clear commitment from Toronto Hydro to increase energy storage capacity through the Non-Wires Solutions program; successful implementation necessitates a centralized dispatching and scheduling platform.

Therefore, Phase 2 involves the implementation of an **Advanced Scheduling and Dispatch** module in the Energy Center which features a consolidated platform for real-time control and management, as well as establishing interoperability between storage management systems and Energy Center. Having a system that provides control capabilities allows the utility to better collaborate on upcoming pilot projects using innovative technologies (e.g. IESO's Grid Innovation Fund), improve use case development for demand response, and simulate and understand risks associated with maturing technologies.

The DER Advanced Scheduling & Dispatch module allows scheduling for objectives such as peak shaving, back feed avoidance, and load flattening. It can create schedules for any level of electrical network hierarchy using any type of controllable DER, including batteries, curtailable wind and solar generators, demand response programs, and backup diesel generators. The time intervals of the schedules can be as little as 5 minutes or as much as 1 hour, and the schedules can be for up to 35 days into the future. As part of implementation into the Energy Centre, the module will support two key functions: (i) Peak Shaving and Control (Dispatch) of DERs; and (ii) Automation of Demand Response. The module is expected to go-live in 2024 following a launch and test of the module on development, quality assurance, and production environment of Energy Center, as well as successful test of schedule and dispatch functionality of at least three utility owned BESS assets.

The module is expected to provide some of the following benefits:

- Enhanced Integration of DERs: optimize and coordinate charging and discharging of utility-managed BESS assets to balance capacity and demand in feeders with current or expected REG assets, which are non-dispatchable;
- Efficient management on a consolidated platform: eliminate reliance on various vendor-managed platforms, eliminating or reduction costs associated with training, maintenance, and licensing as well as quicker and efficient IT upgrades onto one system, reducing downtime; and
- Participate in projects and expanded flexibility service programs: enable Toronto Hydro to participate in upcoming pilot projects related to DERs by facilitating a "plug-and-play" solution for new technologies to be tested, and facilitate studies to quantify value in expansion or new offerings in flexibility services at constrained or soon-to-be constrained areas of the grid.

D5.3.7 Appendix H – Low-Voltage Level Forecasting

1. Introduction and Role in Toronto Hydro's Grid Modernization:

The Future Energy Scenarios (FES) provide an overview of possible future changes to power demand, energy consumption, generation and storage across Toronto, as well as an assessment of their potential impacts on Toronto Hydro's electricity distribution network. FES was contracted through Element Energy, an UK-based energy consulting firm, that has provided similar load forecasting models to various distribution network operators and the electricity system operator in the UK. While the first iteration of FES focused on forecasting load at the bus level, Toronto Hydro is aiming to explore the extension of this modeling exercise to the low voltage network; for example, on the feeder or secondary transformer level. The full FES report can be found in Exhibit 2B Section D Appendix E.

FES is predicated upon a highly granular consumer choice-based analysis of future loading conditions at the desired modelling level (i.e. bus-level, feeder-level), providing a strong evidence base for network planning and the evaluation of future infrastructure investments. To capture the range of uncertainties in a coherent and meaningful way, multiple scenarios are developed (represented as "scenario worlds"), consisting of individual projections for different technology sectors. The scenario worlds represent different energy system pathways, and illustrate the best view of future energy system changes for a given set of economic, social, and policy assumptions.

The projections are created using Element Energy's technology specific bottom-up consumer choice and willingness-to-pay models, which are based on a rigorous understanding of underlying technology costs, consumer behaviour and wider energy market drivers. These projections create uptake scenarios for each of the drivers of demand and generation considered in the FES model. These drivers include, for example, electric vehicles, energy efficiency measures and solar photovoltaic installations.

2. Benefits:

FES establishes a common strategic outlook to support forecasting needs across different Toronto Hydro business functions and various stakeholder engagement and regulatory reporting requirements. FES results give planners insight into the potential geospatial distribution of electrification on the network and allow for detailed analysis into the make-up of that electrification; be it EVs, DERs, or heat-pumps.

The increased granularity that feeder or secondary transformer level modelling provides would give planners even greater levels of detail about the system and further narrow down areas of the network which require investment. For example, feeder or secondary transformer data could be used to confirm the real-time data that is collected as part of the system observability program.

D5.3.8 Appendix I – Innovation Pilot Projects

1. Flexible Connections Pilot

a. Introduction and Role in Toronto Hydro's Grid Modernization:

The rapid integration of Distributed Energy Resources (DERs) assets into the distribution network poses several technical constraints if not proactively managed and coordinated. These include reverse power flow (particularly in low load scenarios), compromised power quality, voltage violations, and elevated fault levels. Consequently, DER customers looking to connect to the network may be faced with financial and time-related burdens associated with network upgrades due to technical and standards constraints. In order to improve customers' ability to access available capacity at an affordable connection cost, alternative solutions could be explored, capitalizing on innovative technological and commercial offerings.

The Flexible Connections Pilot seeks to develop and implement a comprehensive framework that facilitates the efficient and cost-effective integration of DG assets into constrained areas of the distribution network. This would be achieved through development of an advanced DERMS system coupled with intelligent device installation utilized through a communications platform. "Flexible" refers to the network's real-time adaptability in managing network constraints and DG access to network capacity without the need for network upgrades.

b. Description of Pilot:

Flexible DG connections allow DER assets to connect to the network on a constrained basis whereby their operation can be controlled by the network operator within network operational limits. To enable this offering, Toronto Hydro would need to develop both the technical and commercial systems as part of a holistic approach. Firstly, seamless operation of DER assets will require Energy Centre to have the ability to not only monitor, but also control DERs. Real-time awareness of system characteristics will require sensors and smart devices installed on the network – this is currently being achieved as part of Toronto Hydro's Intelligent Grid strategy. The coordination of these devices and the management system will require a robust telecommunications platform to facilitate the necessary information exchange and control capabilities. Finally, extensive customer engagement and the development of novel commercial agreements between the utility and participating DER customers will enable practical implementation. The streamlined approach is geared towards enabling faster, cheaper DER connections while avoiding the need for Toronto Hydro to embark on similarly expensive and time-consuming network infrastructure upgrades.

c. ***Benefits:***

A Flexible Connections pilot allows Toronto Hydro to identify and mitigate any unintended consequences of flexible connections before providing it as a standard offering. Additionally, Toronto Hydro can better understand and manage local DER customer concerns to ensure proposed commercial arrangements are attractive offerings, therefore enabling sufficient trial participation. If implemented, Toronto Hydro would benefit from cost-efficient reinforcement decisions and enabling DER connections with lower electrical losses by locating generation closer to demand. DER customers connecting to the network would benefit from reduced time delays and cost upgrades. Customers could also benefit from earlier participation in future Flexibility Service offerings and increased dynamic control of DG outputs without compromising network safety.

2. EV Commercial Fleets Pilot

a. ***Introduction and Role in Toronto Hydro's Grid Modernization:***

In 2020, fleet energy consumption accounted for 33 percent of CO_2 emissions in the City of Toronto. The successful electrification of commercial fleets is needed to achieve the city's net-zero target by 2040. Specific objectives include having 30 percent of registered vehicles in Toronto be electric and ensuring that 50 percent of the TTC bus fleet is zero-emissions by 2030.

As the demand for system flexibility increases and battery technology costs decrease, the electrification of transportation becomes increasingly important in accelerating the transition to net-zero emissions. However, widespread adoption of commercial fleet electrification may trigger considerable costs to upgrade the distribution system, and may result in significant connection costs due to the higher payloads of commercial vehicles and dissimilarity in load profiles when compared to domestic charging. Therefore, it is essential to investigate and identify the impact of commercial EV fleet charging on the distribution network and develop technical and commercial strategies to facilitate their integration while reducing associated costs for customers.

The unmanaged electrification and charging of fleets could pose a substantial load impact on the distribution system. This project aims to collaborate with fleet owners to assess the impact of commercial EV fleets on the grid, both in terms of quantifying and minimizing load impact. Additionally, the project will explore opportunities to coordinate commercial fleets as a flexible load within the distribution system for both at-home and depot charging scenarios.

b. <u>Description of Pilot:</u>

The Commercial EV Pilot will examine the impact of commercial EV fleet charging at homes and at depots, and optimize charging schemes based on the flexibility requirements/preferences of Toronto Hydro and agreed upon by project partners. These tasks will offer insights into managing charging schemes for the most common charging locations, identifying methods for easy and cost-effective fleet electrification, and optimizing commercial fleet charging while considering flexibility services. Moreover, the project will assess the usefulness and benefits of flexibility services to Toronto Hydro. Additionally, demand forecasting and mitigation planning can be achieved once data is aggregated from the above studies.

The project's scope entails collaboration with major commercial fleet operators to assess the impact of their fleet’s electrification on the distribution system. Various testing methods are employed to gain insight into diverse charging options and develop an effective implementation strategy for fleet operators. The project encompasses quantifying and minimizing the network impact of commercial EVs through trialing different methods, exploring the total cost of ownership of smart solutions for EV fleets operators, and determining the necessary infrastructure to facilitate the EV transition. Technical solutions are tested and implemented by fleet operators and Toronto Hydro, including flexibility services to grid from commercial EV fleets on domestic connections and planning tools for depot energy modeling and optimization with profiled network connections.

c. <u>Benefits:</u>

The project would develop the ability to quantify and minimize the impact of commercial fleet electrification on the distribution network, investigate and quantify the total cost of ownership for intelligent scheduling and charging solutions for EV fleets, and identify the necessary infrastructure, including network, charging, and IT components, to facilitate the transition to EV fleets and enable effective load management.

3. Electric Vehicle Demand Response Pilot

a. <u>Introduction and Role in Toronto Hydro’s Grid Modernization:</u>

The adoption of electric vehicles (EVs) in Toronto is expected to accelerate due to a range of policies, incentives, and grants from all three governments, some of which include: the new Ultra-Low Overnight Electricity Price plan released by the Ontario Energy Board (OEB), a federal proposal for a Zero-Emission Vehicle Mandate (25 percent of all passenger vehicles sales must be electric by 2026, jumping to 60 percent by 2035), and Ontario investment in the construction of two new EV battery plants in St. Thomas. Additionally, Toronto Hydro's own Future Energy Scenarios load forecasting tool (FES) sees 300k BEV cars on Toronto roads by 2030 and 1.8M by 2050 in a Consumer Transformation scenario. This transformative shift poses several network challenges, such as overloading secondary distribution transformers, exerting additional electrical stress on overhead conductors and underground cables, and increasing peak load at various levels. Together, these challenges can lead to distribution system instability; for instance, when a cluster of EV's on the same transformer charge simultaneously. Conversely, beyond low carbon transport, EVs can be leveraged as a DER thanks to the ability to charge and discharge from its battery. In order to maintain system stability and enable EV uptake in Toronto, it is crucial to explore EV demand response strategies in the forefront of change.

The EV Demand Response pilot aims to identify viable technical hardware and control models along with demand response (DR) events to facilitate coordinated charging and potential discharging of EV batteries to support network needs. This would be achieved through development of applications, hardware integration, and mechanisms to identify and trigger EV DR events to support trials and roll-out with Toronto-based market participants.

b. <u>Description of Pilot:</u>

EV demand response programs would allow Toronto Hydro to manage EV charging in real-time based on grid conditions, appropriate to the type of conditions occurring on the network. Currently, phase 1 of an EV Smart Charing pilot is being trialled with Elocity. This explored testing new hardware to convert simple chargers to "smart" by adding a device to connect to the internet and turn on-off as well as inclusion of a customer application and utility portal to trigger DR events. In a subsequent phase, Toronto Hydro intends to explore:

1. A review of available technologies for smart charging;
2. Test technical control options such as the Open Charge Point Protocol (OCPP) with electric vehicle supply equipment (EVSE), leverage other EVSE providers to trigger DR events, and onboard a vehicle telematics control to directly connect with vehicle original equipment manufacturer's (OEM) applications; and
3. Broader corporate tool integration into Energy Center and other metering systems to further real-time situational awareness to deploy EV DR assets to address specific network needs

The pilot would benefit from stakeholder engagement with customers, automakers, EV charge-point manufacturers and operators, industry bodies, and academia to inform and shape a full-scale EV DR program. By developing a strategy that builds on industry-wide learnings, the pilot aims to facilitate the uptake of EVs while helping Toronto Hydro reduce peak demand and defer network upgrades.

c. __Benefits:__

Toronto Hydro is uniquely positioned to evaluate and test relevant mechanisms in the largest city in Canada, where significant EV uptake is expected to occur in the next 10-30 years, and where its urban environment limits the amount of off-street charger installations. If implemented, the pilot is expected to leverage current initiatives and inform future approaches to other Non-Wire Solution programs such as:

- Local Demand Response program – measured meter data from individual chargers can be compared to aggregated transformer meters to verify the impact on the secondary distribution grid
- Hosting Capacity Map – identification of potential capacity constrained areas, providing visibility for medium to long term planning
- Intelligent Grid portfolio – sensors and automation tools being installed under this portfolio can provide real-time visibility and signals for EV demand response trials.

If EV Demand Response is rolled out as a business as usual offering, it could represent a flexible and intelligent solution to managing EV load and maintaining grid stability; one where benefit stacking could be applied in the future as consumer behaviours and markets evolve. Furthermore, EV customers could benefit from increased participation with the utility to better manage electricity use through a wider range of choices on charging times, types, and incentives.

4. Advanced Microgrid Pilot

a. __Introduction and Role in Toronto Hydro's Grid Modernization:__

The increasing frequency of extreme weather events has the potential to cause widespread and extended power outages. This is a particular concern for population segments and services that rely on power for mission-critical needs. An intelligent, whole systems approach is required to create a resilient energy system, ensuring a secure balance between energy supply and demand despite internal/external factors.

The Advanced Microgrid pilot seeks to build upon a white paper completed by Quanta Technologies and perform a desktop study on viable microgrid topologies within Toronto Hydro's network followed by a field demonstration if applicable.

b. <u>Description of Pilot:</u>

Microgrids are electric energy systems that can function while either connected to a main distribution grid or disconnected from it. While disconnected, it is composed of DERs, storage units, and energy loads, and typically uses the same technologies and techniques as a larger utility grid. Microgrids can connect and disconnect from the distribution grid, allowing for the exchange of energy and the supply of ancillary services, and the systems can either be located behind-the-meter (BTM) or front-of-the-meter (FTM).

Currently, the main barrier to widespread implementation of microgrids is financial viability. There continues to be uncertainty and limitations for the various business models proposed for these systems, including revenue structures and pricing schemes. While single-customer microgrids have been tested at research institutes in Toronto and within utilities in the US, there has not yet been a demonstration of multiple-customer or utility microgrids in Toronto as literature review has found that most use cases for microgrids are met in part by existing commercially available technology. These include, but are not limited to, capacity deferrals, improving power quality, providing black start capability, and avoiding DER curtailment. However, gathering data to support microgrid viability in the context of a urban setting requires a demonstration specifically in Toronto Hydro and Ontario's energy system structure in collaboration with project partners such as key accounts, vulnerable customers, and customers with critical loads.

Overall, it is expected the trial will provide clarity on the commercial viability of one or more microgrid models. Key factors include the preferred level of system complexity, level of utility control, public-private investment vs ownership, and evidence supporting regulatory review and reform if required. These factors will help shape the scope and breadth of future microgrid projects that Toronto Hydro would like to see connected to the grid, whether initiated by the utility or its customers. The pilot can also leverage the future DERMS/Energy Centre for dispatch and monitoring of DERs within the microgrid boundary.

c. Benefits:

An advanced grid pilot allows Toronto Hydro to test viable microgrid topologies within the Toronto Hydro network and Ontario energy system structure to determine the commercial viability of grid resiliency and grid services. Additionally, through the course of the pilot, Toronto Hydro would benefit from understanding and managing overall customer and third-party concerns about power safety, quality, and security, which can be used to augment core operations and other NWS programs. If microgrids are provided as a standard offering, either FTM or BTM, Toronto Hydro would benefit from a flexible resource to sustain operations during outages, provide ancillary services to the wider grid, and enable new methods to connect renewable resources. Customers within microgrid boundaries would benefit from a significant reduction in interruptions and outage times as well as participating in new service offerings if applicable.

D6 Facilities Asset Management Strategy

Toronto Hydro manages a broad portfolio of facilities comprised of 185 stations, two control centres, two data centres, and four work centres. These assets house and protect grid equipment, and create the necessary conditions to enable employees to work effectively and efficiently. Investments in the renewal, maintenance, enhancement, and expansion of facilities assets enable the utility deliver its services in a safe, reliable, and sustainable manner.

The primary objectives of the Facilities Asset Management Strategy (the "Strategy") are to maintain the safety, reliability, and functionality of stations and work centres. Meeting these objectives requires the utility to regularly inspect and sustain its facilities assets and the critical building systems in good working order. In addition to these table stakes, the Strategy addresses emerging needs and priorities to expand the distribution grid to serve growing customer demand, enhance facilities assets to decarbonize Toronto Hydro's emissions, and provide greater resilience against physical threats such as vandalism and natural threats such as extreme weather.

The Strategy governs Toronto Hydro's facilities Investment Planning and Forecasting ("IPF") process through the following streams, which are described in more detail below.

1. Asset Management Process
2. Facilities Enhancements Initiatives
3. Long-term Planning Considerations

The scope of investments covered by the Strategy includes the following types of facilities assets and building systems:

- Structural and envelope assets such as walls, façades, beams, and columns;
- Architectural and interior assets such as roofs, doors, finishes, and ceilings;
- Fire and life safety assets and systems such as fire alarms, sprinklers, signage, and emergency lighting;
- Mechanical, electrical, and plumbing assets and systems such as HVAC, lighting, plumbing fixtures, sump pumps, and hot water tanks; and
- Civil and sitework assets such as walkways, driveways, parking spaces, gates, and barriers.

D6.1 Asset Management Process

Toronto Hydro facilities asset management process is aligned and integrated with the utility's overall Asset Management strategy detailed in Exhibit 2B, Section D1.

The condition and lifecycle stage of an asset are the primary considerations in the development of the facilities asset investment plan. Generally, the utility replaces facilities assets that are identified to be in poor condition and past useful life. After an asset is identified as having these characteristics, the utility implements a plan to upgrade or replace the asset to restore and enhance its functionality in accordance with current standards and objectives.

Toronto Hydro considers the following types of inputs in the asset lifecycle management process:

- Building Conditions Assessment ("BCA");
- Asset Registry data maintained through Toronto Hydro's Computerized Maintenance Management Software ("CMMS");
- Industry standard useful life data (i.e. ASHRAE and RS Means Data);
- Assessments and reports by experts (e.g. Asbestos Containing Materials Report, Designated Substances Report, Water Infiltration Report, Roof Condition Assessment, lighting assessment reports, Current Condition and Code Compliance of Vertical Service Ladders, and Security Systems Assessment);
- Lessons learned from past projects; and
- Business impact to Toronto Hydro.

The Building Condition Assessment ("BCA") is central to evaluation and prioritization of asset renewal investments which feed into the utility's overall planning process described in Exhibit 2B, Section D1.

To enable the BCA, the utility collects and analyzes information about the condition of its facilities assets on an ongoing basis, as follows:

- **Daily:** Asset condition observations are captured on a daily basis through the Preventive Maintenance Program ("PMP") and the CMMS system.
- **Monthly:** Toronto Hydro conducts monthly field inspections and safety audits to review asset condition observations captured in the CMMS and perform preventive checks.

- **Annually:** The utility annually reviews asset condition observations captured in the CMMS through the daily and monthly processes, as well as lessons learned from that year's projects, to verify and revise the BCA score for each building as required; and
- **Biennial:** Toronto Hydro resets the BCA cycle and fully re-evaluates buildings biennially.

The BCA follows the Uniformat II categorization, which assigns each building asset and system three scores for each of the following parameters:

Table 1: Building Condition Assessment Uniformat II Categories

Rating	Current Condition	Probability of Failure	Impact of Failure
1	Critical – not serviceable or irreparable	System Failure – Immediate Attention	Critical System
2	Poor – not functioning as intended	Imminent Breakdown - Critical (1-2 Years)	Building Functionality
3	Fair – functioning with noticeable wear/use	Imminent Breakdown – Non-Critical (Rate Plan)	Run-to-Fail
4	Good – functioning with minor wear/use	Improbable Breakdown – (5-10 Years)	Redundancy of Cost-Effective Upgrade
5	Excellent – in new or near-new condition	Highly Improbable – (10+ Years)	Elective Upgrade

The scores are then combined in a weighted formula, along with site priority factors based on building usage, to provide a single ranking known as the Risk Priority Number ("RPN"). The RPN supports Toronto Hydro's decision-making by pinpointing the most critical needs by building system and provides a ranked, quantified evaluation of assets.

D6.1.1 Lifecycle Analysis

Lifecycle economic analysis is an important aspect of cost-effective lifecycle asset management. The objective of this analysis is to minimize the asset's total lifecycle cost while ensuring safe and reliable asset performance. Toronto Hydro achieves this objective by tracking the end of economic life, which is the point where total cost of the asset (including ownership and maintenance costs) is at its lowest over the asset's lifecycle. Along with the BCA and other inputs discussed herein, the lifecycle analysis enables Toronto Hydro to make well-informed asset renewal investment decisions.

D6.1.2 Legislative and Technical Standards

Toronto Hydro's facilities standards are based on legislative requirements and technical, professional, or regulatory standards. The former include the Ontario Building Code, the Ontario Fire Code, and *Accessibility for Ontarians with Disabilities Act, 2005*.

Technical standards vary from project to project and may include: ASHRAE (American Society of Heating, Refrigerating and Air-Conditioning Engineers); ESA (Electrical Safety Authority); TSSA (Technical Standards and Safety Authority); CSA (Canadian Standards Association); EUSR (Electrical Utility Safety Rules); and in the future, ISO55001 (International Organization for Standardization – Asset Management).

D6.2 Facilities Enhancements Initiatives

In prioritizing facilities asset investments, the top drivers are safety (including compliance with legislative requirements), reliability of electrical distribution equipment, and functional availability to ensure business continuity. Once investments have been triggered by one or more of these drivers, Toronto Hydro evaluates whether there is opportunity for the asset's repair or replacement plan to have increased enhancement to achieve additional goals, including greater resilience against natural and physical threats such as extreme weather and vandalism, or deliver reductions in greenhouse gas emissions, including advancing energy efficiency outcomes.

Weather Resilience and Physical Security Enhancements: The natural, physical, social, and geopolitical circumstances affecting Toronto Hydro's distribution system also affect the utility's facilities and drive a key part of facilities enhancements. As discussed in Exhibit 2B, Section D5, the effects of climate change such as rising average annual temperatures, average annual precipitation, and extreme temperature and precipitation patterns require Toronto Hydro to prepare its infrastructure—including its facilities supporting the core distribution infrastructure—to withstand and adapt to these conditions. Separately, but equally importantly, hardening stations and work centres to prevent and mitigate physical security risks such as unauthorized access, vandalism, theft, trespassing, workplace violence, or terrorism is essential to ensuring the security and safety of the utility's personnel and the general public, and the reliability of the distribution system, especially in the face of pervasive cyber security threats emerging against the electric utilities sector. As described in Exhibit 2B, Section E8.2, Toronto Hydro plans to address these needs through targeted investments in renewing stations and work centre assets (such as exterior cladding, windows, and roofs where critical equipment is housed), and improvements to security systems (e.g. the installation of network-based cameras and access card readers).

Energy Efficiency and Decarbonization Enhancements: In 2022, natural gas equipment in Toronto Hydro buildings contributed approximately 25% of the utility's total direct greenhouse gas emissions.[1] As detailed in Exhibit 2B, Section D7, Toronto Hydro's goal is to reach Net Zero emissions by 2040. To achieve this important goal in a gradual and paced manner, the utility intends to incorporate equipment swaps (e.g. natural gas to electric) and upgrade its facilities to improve energy efficiency (e.g. through increasing building envelope insulation and LED retrofits) where possible.

D6.3 Longer-Term Planning Considerations

As part of the IPF process, Toronto Hydro evaluates whether property purchases will be required to accommodate the future expansion needs of the distribution system. For example, this may include the need to construct new transformer stations to increase the grid's peak capacity or the siting of other equipment such as energy storage systems to enable the connection and integration of renewable electricity generation facilities. When facilities investments are required to support grid expansion, the Facilities Asset Management team collaborates with the Capacity Planning team to evaluate and integrate facilities investment options and incorporate them into the business case for particular projects, such the Downsview TS business case in the Stations Expansion program (Section E7.4).

The utility owns a small number of municipal stations properties that are decommissioned and no longer functioning to distribute electricity to customers. To determine if these properties can be designated as surplus to be disposed, Toronto Hydro evaluates whether the property is suitable for future grid expansion. The evaluation includes the costs and benefits of a potential sale versus the ongoing property maintenance and operation costs to ensure that the decision to sell or retain the property is financially sound.

[1] Exhibit 2B, Section D7.

Stations buildings house critical distribution equipment such as power transformers and switchgear. When these assets are planned for expansion or major upgrades, Toronto Hydro must also take the necessary steps to ensure that major building systems are functional and up-to-date prior to installing the new equipment. As an example, such systems include building waterproofing and flood management systems that protect electrical equipment and other important structural infrastructure from leaks. Therefore, Toronto Hydro plans and executes investments to support stations upgrades and expansions ahead of major capital projects at stations to ensure safety, reliability, and business continuity.

Similarly, for work centres, Toronto Hydro looks ahead to evaluate if it can accommodate and functionally support future resourcing requirements. As the utility's workforce expands to deliver capital and operations programs and address new requirements and objectives supporting the energy transition, additional work centre investments may be required to accommodate more staff. Those investments have not yet been built into the 2025-2029 plan as the utility continues to evaluate options for its head office strategy, as discussed below.

D6.3.1 Head Office Strategy

The 14 Carlton head office's location in proximity to Union Station and public transit lines enables Toronto Hydro to attract and retains talent from the Greater Toronto Area ("GTA").

The head office building poses several limitations that make its upkeep challenging, noted below:

- **Safety**: the building has an aged standpipe system with fire hose cabinets and no overhead automatic sprinklers, requiring manual fire suppression with a fire hose.
- **Mechanical**: the current heating and cooling system is an outdated 5-pipe system. Limitations on headroom clearance between floors and a controls system past useful life mean that any upgrade to a modern HVAC system would be very costly and challenging.
- **Electrical**: the building's voltage is not up to date with electrical service standards and the building is at its electrical service capacity. Upgrades would require rewiring the building and installing a new vault to upgrade electrical capacity.
- **Historical Site**: the property is designated under Part IV of the *Ontario Heritage Act*, which requires heritage permitting for building envelope repairs. This limits façade projects and repairs and opportunities for modernization (e.g. the installation of modern external HVAC ducting).

- **Layout**: the office layout has been built around the vintage architectural and structural elements, which pose limitations on efficient layouts for workstations, resulting in a less-dense workspace than what would be possible given the available square footage.
- **Environmental:** due to the building's age, it contains hazardous materials, including asbestos, that must be considered in all projects and that incur increased hazard management costs, longer times for project schedules, and business impacts.
- **Energy Efficiency: t**he building's age and structural limitations render it challenging and costly to achieve energy efficiency and decarbonization goals.

Significant renewal investment is required to remediate the risks and deficiencies of the head office. However, in an effort to manage costs responsibly, the Strategy takes a unique approach to this nearly one-hundred-year-old head office, compared to stations buildings of similar age and heritage protection that house critical grid distribution equipment which serves many customers. Over the 2025-2029, Toronto Hydro intends to evaluate options for the long-term investment strategy of the head office. While this analysis is pending, the utility plans to continue with a method of "managed deterioration" at the head office, engaging in reactive stopgap repairs to address safety, ensure compliance with legislative requirements, and maintain business continuity.

D7 Net Zero 2040 Strategy

To mitigate the impacts of climate change, Toronto Hydro is committed to reducing its direct greenhouse gas ("GHG") emissions (referred to as Scope 1 emissions) in order to reach "net zero" by 2040.[1]

Toronto Hydro's Net Zero by 2040 strategy builds upon the utility's record of climate action and environmental leadership.[2] Environmental leadership actions include implementing energy efficiency measures at stations and work centres, programs to increase waste diverted from landfills, reducing paper use, and facilitating the installation of renewable energy generation resources and battery energy storage systems for customers and as part of the utility's distribution system.

The City of Toronto (Toronto Hydro's sole shareholder) has declared that climate change is an emergency requiring immediate and sustained action, and has initiated an ambitious plan to achieve net zero community-wide emissions by 2040. Additionally, the Government of Canada passed the *Canadian Net-Zero Emissions Accountability Act*,[3] establishing a legally binding requirement for the federal government to establish a GHG emissions reduction plan for achieving net zero emissions in Canada by 2050.[4] Finally, the Province of Ontario has established a target of reducing GHG by 30 percent below 2005 levels by 2030.[5]

The International Panel on Climate Change ("IPCC") concluded that global warming of 1.5°C is hazardous to humans and natural ecosystems, and should be limited as much as possible. The risks of climate change for Toronto Hydro's operations include more frequent and severe storms and extreme heat, and increased flooding and lightning strikes.[6] These risks significantly endanger the utility's operations and are already manifesting. Severe weather in 2021 caused $2.1 billion of insured damage in Canada, compared to an average of $422 million a year between 1983 and 2008.[7]

[1] The utility's direct or "Scope 1" emissions are primarily emitted by its buildings, its vehicle fleet portfolio, and its sulfur hexafluoride-insulated (SF_6) electrical distribution equipment.
[2] Toronto Hydro, Environmental Performance, https://www.torontohydro.com/about-us/environmental-performance
[3] Canadian Net-Zero Emissions Accountability Act, S.C. 2021, c. 22.
[4] Canadian Net-Zero Emissions Accountability Act, S.C. 2021, c. 22, ss. 6-7.
[5] Government of Ontario, Climate Change, https://www.ontario.ca/page/climate-change: Target to reduce GHG emissions to 30% below 2005 levels by 2030.
[6] International Panel on Climate Change, IPCC, AR6 Summary for Policymakers at page 14, https://www.ipcc.ch/report/ar6/wg2/downloads/report/IPCC_AR6_WGII_SummaryForPolicymakers.pdf
[7] Insurance Bureau of Canada, News & Insights, Severe Weather in 2021 Caused $2.1 Billion in Insured Damage, "online", https://www.ibc.ca/news-insights/news/severe-weather-in-2021-caused-2-1-billion-in-insured-damage

Weather events leading to significant outages, such as the wind storm that occurred in May 2022, are anticipated to increase in frequency and severity as the climate continues to change.

Near-term GHG emissions reductions and mitigation actions are critical to reducing the adverse impacts, damages and losses from climate change.[8] To this end, Toronto Hydro is acting to reduce the GHG emissions it produces, with the target of emitting as close to zero emissions by 2040 as possible and purchasing carbon credits or enabling carbon sinks to offset any remaining emissions so that the utility reaches "net zero" direct emissions. Toronto Hydro's primary effort is to reduce its direct GHG emissions and credible offsets will only be used to eliminate remaining GHG emissions if zero direct emissions cannot be attained. The sections below review the three main types of direct emissions that Toronto Hydro produces and the utility's plan to reduce each to net zero by 2040.

With this plan, Toronto Hydro is building on its track record of environmental leadership.[9] Since 2013, the utility reduced its direct GHG emissions by 26 percent by increasing buildings' energy efficiency, minimizing fleet vehicle idling time, and electrifying light-duty fleet vehicles. Toronto Hydro intends to sustain these emissions reductions and implement new initiatives to reduce the remaining emissions to net zero. These investment objectives are part of Toronto Hydro's 2025-2029 investment plan which was put to customers for feedback as part of the Phase 2 Customer Engagement survey.

Toronto Hydro's 2025-2029 custom scorecard includes a measure tracking the utility's progress against a target to reduce 2.6 kilo tonnes of carbon dioxide (CO2) and carbon dioxide equivalents (CO2E) by the end of the rate period. This measure holds the utility accountable to its customers and stakeholders for delivering on the commitment to reach net zero by 2040 to mitigate the impact of climate change.

Toronto Hydro's Vehicle Fleet Emissions

Toronto Hydro's fleet produced 23 percent of its direct emissions in 2022, making this transition strategy a critical component of the utility's net zero by 2040 objective. Toronto Hydro is reducing the emissions produced by its fleet of vehicles by transitioning its procurement standards to prioritize electric and hybrid vehicles whose motors are powered by clean electricity (as per the IESO, over 90

[8] *Supra* Note 6
[9] *Supra* Note 2

percent of Ontario's electricity system is currently emissions-free).[10] Emissions from an electric vehicle are up to 90 percent less than a similarly sized internal combustion engine ("ICE") vehicle.

In addition to decreased emissions, electric and hybrid vehicles are a sound financial investment as they incur lower operational costs due to decreased fuel consumption and vehicle maintenance requirements. The Federal Government has established a price on carbon pollution, which will rise from $65/tonne to carbon dioxide equivalent (tCO2e) in 2023 to $170/tCO2e in 2030.[11] As a result, the price of fuel for ICE vehicles will continue to increase each year. Currently, driving an electric vehicle reduces the annual cost of fuel and maintenance by $1,500 to $2,000 each year. These savings will continue to rise as the price of carbon continues to increase the price of fuel.

Toronto Hydro currently owns and operates 13 electric and 20 hybrid light-duty vehicles. Toronto Hydro plans to continue to purchase fully electric or hybrid light-duty vehicles in a paced manner. Consumer demand and supply chain factors, including manufacturer capability and battery availability, currently pose some limitations on vehicle availability. Toronto Hydro mitigates this risk by using lifecycle assessments to determine when vehicles will need to be replaced and accordingly placing orders for longer lead time purchases of electric vehicles. Toronto Hydro also extends the lifecycle of vehicles to allow time for the procurement of electric or hybrid replacements where the total cost of ownership (including the maintenance costs, replacement costs incurred while the vehicle is unavailable for maintenance, and sunk costs) of extending the vehicle lifecycle does not exceed the estimated total cost of ownership of a new ICE vehicle.

Many vehicle manufacturers are committed to increase the production of electric vehicles and stopping the production of ICE vehicles by 2040.[12] Toronto Hydro's plan to transition to electric and hybrid vehicles protects the utility from manufacturing availability risk and allows the utility to pace its procurement in a fiscally responsible manner that avoids the risk of stranded asset costs.

While manufacturers are committed to increasing electric vehicle production, heavy-duty electric vehicles (such as bucket trucks) remain an emerging technology characterized by a rapidly evolving

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[10] Independent Electricity System Operator ("IESO"), Pathways to Decarbonization Report (15 Dec 22) at page 6, https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization
[11] Government of Canada Federal Benchmark for Carbon Pollution Pricing System, 2023-2030, https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html
[12] Accelerating to Zero Coalition, Signatories, Automotive Manufacturers, https://acceleratingtozero.org/signatories-views/

market. As a result, Toronto Hydro cannot yet conclude whether the heavy-duty electric vehicles that are currently available on the market will meet the utility's functional needs and provide sufficient reliability to service the distribution system in emergency situations. As a result, Toronto Hydro is deferring the large-scale transition to fully electric heavy-duty vehicles to the next decade. The utility intends to stage for success of future large-scale adoption of heavy-duty electric vehicle technologies through trials in the 2025-2029 rate period. These trials can enable Toronto Hydro to better understand how this emerging clean technology can be effectively integrated into its critical operations, and to leverage that experience and understanding to support commercial and industrial customers in their fleet electrification journeys.

While the transition to electric vehicles is ongoing, Toronto Hydro will continue to operate and maintain ICE vehicles such as pick-up trucks, cube vans and bucket trucks. Toronto Hydro is using idling reduction technology and biofuels to reduce its fleet emissions in the near term while the utility's fleet still includes combustion engines. Employee communications on electric vehicle use and idling reduction are also used to encourage employees to role model emissions reduction behaviours.

Fleet electrification is discussed in further detail in the Fleet and Equipment capital program (Exhibit 2B, Section E8.3) and the Fleet and Equipment Services OM&A program (Exhibit 4, Tab 2, Schedule 11).

Toronto Hydro's Facilities Emissions

In 2022, the utility's consumption of natural gas at its occupied buildings produced 26 percent of its direct GHG emissions. Toronto Hydro has a paced plan to gradually reduce its buildings emissions by decreasing its natural gas consumption using a combination of energy conservation measures and fuel switching projects. Energy conservation measures include the installation of air curtains and light-emitting diode ("LED") lights to increase the energy efficiency of the utility's buildings. Fuel switching projects include replacing natural gas fueled heaters with electric heating systems. The energy input requirements for an air source heat pump are less than a similarly-sized natural gas system since heat pumps are more efficient.[13] As a result, fuel switching to heat pumps also contributes to the utility's energy efficiency goals in addition to its decarbonization goals.

To smooth and constrain investment profiles, Toronto Hydro intends to take a paced approach to this work, increasing energy efficiency at its buildings to reduce natural gas consumption before fully transitioning from natural gas to electricity. This approach reduces the overall volume of electrical heating and cooling assets that the utility would have to install and provides energy savings through efficiency. Finally, a paced approach enables Toronto Hydro to minimize interruptions to its business operations by effectively scheduling building upgrades and equipment replacements to coordinate with the times the work centres are occupied by employees, rather than conducting the work reactively and interrupting normal business operations. This work must commence in the 2025-2029 rate period in order to execute a paced approach and realize the associated benefits of smoothing the investment costs and minimizing operational disruptions.

Toronto Hydro's plan to reduce natural gas emissions by electrifying buildings' heating and cooling systems puts Toronto Hydro in a position of proactive alignment with current and future government policy developments that restrict or ban natural gas heating. In its Transform TO Net Zero Strategy, the City of Toronto indicated the need to "accelerate a rapid and significant reduction in natural gas use" stating that "catalyzing the electrification of building heating systems, as a preferred alternative to the use of fossil-fuel heating systems, will be key."[14][15] The City further stated in that document that the use of natural gas in buildings must be phased out by 2040 to achieve its net zero targets.[16] Similar policy proclamations could be made by other levels of government if the urgency of climate change action intensifies, and if they are made, Toronto Hydro would be in a position of proactive alignment.

One of the factors Toronto Hydro considered in establishing the plan to reduce emissions from its buildings is the optimal lifecycle of its assets.[17] The optimal lifecycle considers the operational costs of maintaining and operating existing equipment against the cost of capital investments in

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[13] Natural Resources Canada, Publications, Heating and Cooling with a Heat Pump, https://natural-resources.canada.ca/energy-efficiency/energy-star-canada/about/energy-star-announcements/publications/heating-and-cooling-heat-pump/6817#b5

[14] City of Toronto, Transform TO Net Zero Strategy, November 2021, Attachment B, p. 8, https://www.toronto.ca/legdocs/mmis/2021/ie/bgrd/backgroundfile-173758.pdf

[15] Ibid.

[16] Ibid, p. 6.

[17] See Facilities Asset Management Strategy, Exhibit 2B, Section D6.

replacement assets on an ongoing basis. Changing maintenance and replacement costs influence the optimal lifecycle cost model. To this end, the rising price on carbon pollution impacts the cost of Toronto Hydro's natural gas consumption. Toronto Hydro's emissions reduction plan can avoid up to $330,000 in carbon tax costs associated with natural gas by 2030, assuming the carbon tax continues to increase annually by $15 per tonne.[18]

The investments required to reduce emissions from buildings are discussed in further detail in the Facilities Management and Security capital program (Exhibit 2B, Section E8.2) and the Facilities Management OM&A program (Exhibit 4, Tab 2, Schedule 12).

Toronto Hydro's Sulfur Hexafluoride (SF6) Emissions

Emissions from Toronto Hydro's SF6-insulated equipment represented 51 percent of its total direct emissions in 2021. Toronto Hydro intends to limit SF6 emissions, and the associated GHG emissions, through the elimination of SF6 leaks from existing distribution equipment and reducing the installation of new SF6-containing equipment where feasible. This plan is intended to minimize the release of potent emissions and prepare for anticipated legislation. SF6 is a potent GHG with a with a global warming potential 22,800 times greater than carbon dioxide. SF6 has been used in electrical transmission and distribution equipment in the electricity industry since the 1950s due to its excellent insulating properties and stability.[19] Toronto Hydro has used sealed SF6 equipment since the 1950s and in some instances, in place of air-vented equipment to mitigate the risk of failure due to ingress of dirt, road contaminants, and flooding. Reliability, safety, and environmental implications are critical considerations in determining the optimal method of eliminating SF6 emissions.

The energy sector is under increased pressure to reduce reliance on SF6 because it is a potent GHG. Legislation is expected to limit the use of SF6 in the future. Such legislation has already been implemented in other jurisdictions, including California.[20] Proactively minimizing the use of SF6 reduces Toronto Hydro's operational risks, as replacement costs would be material if Toronto Hydro were required to comply with new legislation on short notice, increasing the risk of stranded assets and operational replacement costs.

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[18] *Supra*, Note 11.
[19] United States Environmental Protection Agency, Sulfur Hexafluoride (SF6) Basics, "online", https://www.epa.gov/eps-partnership/sulfur-hexafluoride-sf6-basics
[20] California Air Resources Board, Regulation for Reducing Greenhouse Gas Emissions from Gas-Insulated Equipment, Title 17, "online", https://ww2.arb.ca.gov/sites/default/files/2022-05/gie21-final-regulation-unofficial.pdf

Toronto Hydro plans to install assets that use alternatives to SF6, such as solid dielectric transformers, in order to meet its Net Zero 2040 target and prepare for any anticipated legislation. The utility's approach addresses challenges associated with eliminating SF6 emissions, including leak detection difficulties and a lack of operationally suitable alternatives. Toronto Hydro identified alternatives, such as solid dielectric equipment, for approximately 75 percent of existing SF6 applications. However, the balance of approximately 25 percent cannot be replaced at this time as the currently available alternative equipment does not have sufficient rating for the required electrical current. As a result, Toronto Hydro must take a two-pronged approach to mitigating SF6 emissions:

1. Eliminate SF6 use where operationally feasible; and
2. Improve leak prediction and detection capabilities to address SF6 emissions proactively.

This approach is embodied in Toronto Hydro's Underground System Renewal – Horseshoe capital program, discussed in Exhibit 2B, Section E6.2. This program details the investments that Toronto Hydro intends to make in solid dielectric switchgear to try it as an alternative option to SF6-insulated switchgear.[21]

Toronto Hydro is committed to eliminating SF6 by installing alternatives in all new construction projects where doing so is operationally feasible and where physical space, cost, design standards, and equipment availability allow Toronto Hydro to trial viable alternatives to SF6 insulated equipment. The utility is also exploring other insulation alternatives to SF6 gases; however, these gases are not currently widely deployed by other utilities and remain at the pilot stage.

Toronto Hydro also continues to improve leak prediction and detection capabilities to address SF6 emissions proactively.[22] The utility investigates the cause of failures in SF6 equipment to identify trends and enhance the inspection process to allow greater focus on common failure points. The investigation data also allows Toronto Hydro to identify the equipment types and manufacturers that are experiencing quality issues and select vendors that supply more reliable equipment. The utility communicates the common failure points identified through investigations to manufacturers to improve the manufacturing process. For example, when the investigation process identified multiple leaks from bushings related to welding issues, Toronto Hydro worked with the relevant manufacturer

[21] Underground System Renewal – Horseshoe, Exhibit 2B, Section E6.2, p. 31.
[22] Preventative and Predictive Maintenance – Underground, Exhibit 4, Tab 2, Schedule 2, Page 2 & 24; Preventative and Predictive Maintenance – Stations, Exhibit 4, Tab 2, Schedule 3, Page 3

to improve the welding inspection process prior to equipment delivery. Additionally, the utility installed SF6 leak detection alarms for some equipment. These alarms provide early notification when a leak condition exists and enable rapid mitigation of impacts to the environment.

Conclusion

The 2025-2029 investment plan supports Toronto Hydro’s Net Zero 2040 by strategy through investments in the electrification of Toronto Hydro’s fleet and buildings, enhancements to building envelope efficiency, and elimination of SF6 emissions from equipment. These investments mitigate business continuity risk and manage long-term costs associated with decarbonization policies, such as the federal tax on carbon emissions. Deferring these investments to future periods would entail greater disruption to business operations, thereby increasing expenses and hampering productivity. Paced decarbonization investments also protect Toronto Hydro and its ratepayers against the risk of sudden legislative changes governing the use of SF6 gas and phase-outs of ICE vehicles which could require corporations like Toronto Hydro to decarbonize their emissions in an accelerated manner.

D8 Information Technology Investment Strategy

Informational technology ("IT") is a critical enabler for utility operations. Toronto Hydro relies on IT assets and systems to satisfy its obligations as a distributor, deliver its capital plans and operational programs, and pursue efficiencies and innovation.

The primary objective of Toronto Hydro's IT Asset Management and Investment Planning Strategy (the "Strategy") is to derive sustainable value from IT assets for the utility and customers. IT systems provide optimal value when they deliver expected levels of service in a sustainable manner and effectively mitigate ongoing risks (e.g. impacts of failure, cyber security) at optimal costs. This schedule describes the IT asset management principles and IT investment planning methodology that enables Toronto Hydro to achieve this key objective.

IT asset management includes the purchase, operation, maintenance, renewal, replacement and disposition of IT data, hardware, and software assets. IT asset management is defined by IT standards, and includes:

- Requirements for data, hardware, and software assets (e.g. physical, performance, compatibility, security, etc.);
- IT architecture establishes expected service levels (e.g. performance measurement, reliability requirements, incident / problem management for the assets); and
- Lifecycle management schedules for each type of asset.

Sustainment is necessary for maintaining the functionality and currency of existing IT systems. Enhancement involves improving existing systems and facilitating their organic growth requirements, such as meeting the needs of increasing numbers of staff or customers. Transformation refers to implementation of new systems or modules that add new business capabilities, provide higher protection levels for digital assets and safeguard customer and employee privacy.

To enable the Strategy, Toronto Hydro uses well-defined IT standards and up-to-date IT asset information. To that end, the utility uses an internal framework which provides high-level criteria to consider in the IT investment decision-making process. The process leads to the development of a five-year roadmap of prioritized investments, including a detailed plan for the first year.

D8.1 IT Asset Management

Toronto Hydro developed IT standards to streamline and optimize the lifecycle of IT assets, define system architecture, and gain operational efficiencies through the standardization of IT assets and components. The utility defines its IT standards based on information provided by equipment vendors (e.g. statistics on mean time to failure), internal historical data regarding asset failures, and industry best practices, and reviews its IT standards regularly to ensure that they remain current and relevant for the utility.

Toronto Hydro adopted distinct yet mutually reinforcing IT standards and architecture for data, hardware, software, security, assets and standards for processes (e.g. testing, monitoring and alerting), as described in greater detail below. For example, having aligned hardware and software standards enables the utility to implement virtualized hardware platforms—a collection of hardware resources which are required to complete desired computing operations that exceed the requirements of a single hardware machine.

The virtualization of the infrastructure provides the following benefits:

- Better management of IT assets, incidents, problems, changes, configurations, security, capacity, and availability of IT assets;
- Enhanced reliability of IT systems;
- Streamlined procurement processes and reduced operating costs;
- Operational efficiencies;
- Simplified monitoring of IT assets;
- Enhanced security; and
- Easier migration to new hardware and technology, including cloud solutions where required.

D8.2 IT Hardware Standards

IT hardware standards define the management of the physical IT components from acquisition through disposal. Common IT hardware asset management practices include resource forecasting, procurement management, life cycle management, redeployment, and disposal management. Toronto Hydro applies these practices to the categories of hardware assets described in Figure 1 below.

Core Backend Infrastructure Assets

- Responsible for the computation, storage and communication necessary to support IT systems:
- **Computing**: servers and security appliances;
- **Storage**: disk arrays, flash arrays, backup systems; and
- **Communication**: network and telephony assets.

Endpoint Assets

- Enable end-users to execute, process, complete and review business tasks and operations:
- **Computing:** desktops, laptops and tablets;
- **Printing**: printers and plotters; and
- **Communication:** desk phones, mobile phones.

Figure 1: IT Hardware Asset Categories

IT hardware and architecture standards specify which types of hardware assets Toronto Hydro requires to ensure a highly reliable, scalable and manageable platform for business applications, and document the capacity and lifecycle of these different assets.

The utility must periodically refresh IT Hardware assets to guarantee expected service levels of the systems and minimize the risk of asset failure and impact to the business or customer services (e.g. from the failure of assets supporting customer-facing applications such as the self-service portal or outage map). Through its IT hardware standards, Toronto Hydro seeks to define the optimal timing of asset replacement such that the utility operates hardware assets with the lowest acceptable failure rate at optimal costs. As illustrated in Figure 2 below, the lifecycle of IT assets generally follows a “bath tub curve” that breaks out into three distinct regions:

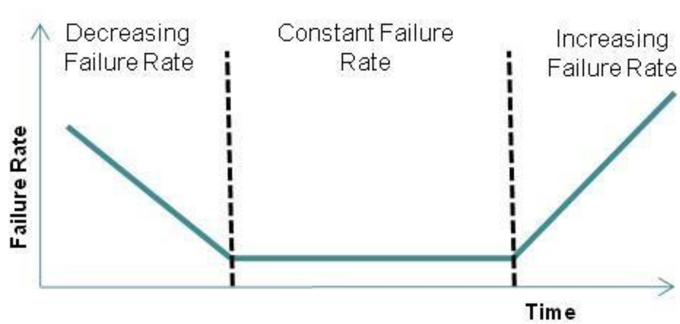

Figure 2: IT Hardware Asset Lifecycle Failure Rate over Time

- **Decreasing Failure Rate:** This is the region of the curve associated with a reduced failure rate over time. This is typical in the release of a new product, where once upfront implementation issues and defects are addressed, failure rates tend to drop.
- **Constant Failure Rate:** As a failure rate decreases to a certain low point, it stabilizes and remains virtually constant. The cost of ownership in this area of the bathtub curve is steady and financially optimal.
- **Increasing Failure Rate**: As the product ages beyond useful life, its failure rate starts to increase again due to general operational wear and tear. As a result, system failures and associated maintenance costs start to rise steeply in this portion of the bathtub curve.

Based on the criticality of the infrastructure, industry best practices, and vendor specifications, IT hardware standards define the optimal time for asset replacements before reaching the "Increasing Failure Rate" portion of the lifecycle. This approach minimizes the risk of interruption to the core processes and technology that Toronto Hydro relies on to execute its capital plans and operational programs. This approach also helps the utility incur IT-related operational and capital expenditures prudently and at reasonable levels, while also increasing the flexibility to adapt IT infrastructure in accordance with customers' evolving needs and preferences and changing business circumstances.

D8.3 IT Software Standards

Toronto Hydro categorizes its software applications as Tier 1, Tier 2 and cloud-based solutions. The criteria used to classify these applications include the level of impact on critical business functions, system complexity, maintenance costs, and the number of application users.

- **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. As a result, Tier 1 applications generally have higher maintenance costs and a larger user base than Tier 2 applications. Examples of Tier 1 applications include the Enterprise Resource Planning System, Network Management System, and Geospatial Informational System.

- **Tier 2** applications enable divisional and departmental processes. These applications have less complex integration with other enterprise applications, and are typically supported by infrastructure with a lower complexity and lower target for overall availability. Tier 2 applications generally have lower maintenance costs, and cater to a smaller user base than Tier 1 applications. For example, several of Toronto Hydro's operational divisions use ProjectWise as a document management system. Another example of a Tier 2 system is Power Monitoring Expert, used by the utility's engineers to provide insights into electrical system health and energy efficiency.

- **Cloud-based** applications enable both company-wide and specific business processes. The unique feature of a cloud-based solution is that it resides on vendor infrastructure and is accessed through the internet. Toronto Hydro establishes system service level agreements with each cloud service provider to set service conditions, e.g. relating to business continuity and cyber security. An example of a cloud-based application is Intelex which Toronto Hydro uses to manage health and safety inspections and incident reporting processes. Another example is Oracle Field Services Cloud (OFSC), a mobile workforce management system that allows dispatchers and field crews to collaboratively manage major events, assemble crews, manage priorities, and communicate across different groups to respond to major events in a timely and effective manner.

Toronto Hydro enhances system functionality, reduces the risk of system failures and cyber security breaches, and aligns its software assets with vendor support cycles through regular software upgrades. Continuing to run and rely on software applications beyond the end of vendor support increases the risk to system reliability and of greater exposure to cyber security threats. Similar to IT hardware assets, if an application is not upgraded before the vendor support cycle expires, Toronto Hydro may need to procure specialized technical resources to maintain and support the application. Timely software upgrades also help reduce unforeseen IT-related operational and capital expenditures by minimizing the risk of asset failure.

Through its IT software standards, Toronto Hydro seeks to maintain the compatibility of software applications with the underlying components (e.g. servers and operating systems) to ensure uninterrupted IT system operations and deliver the desired end user experience and functionality. Since many IT systems and their underlying components are often on different end-of-life and vendor support cycles, maintaining compatibility among various software applications can be a complex task. Nonetheless, it is a key consideration in mitigating security and reliability risks to IT systems from the underlying components.

Toronto Hydro's IT software standards consider average vendor release cycles, as well as the need to minimize incompatibility risks with underlying components. Through the application of the Strategy, the utility implements software asset upgrades depending upon need and risk factors, including where the asset reaches its maximum age or is more than one version behind the latest vendor-released version, or based on specific compatibility drivers and considerations (e.g. hardware upgrades).

D8.4 IT Cyber Security Standards

With the emergence of advanced persistent threats and nation-state actors, advanced cyber security attacks against critical infrastructure are becoming more widespread. The proliferation of a large number of potentially exploitable internet of things (IoT) devices (e.g. for home automation) enables attackers to form "botnets" to perform large-scale distributed denial of service (DDoS) attacks against enterprises.[1] Furthermore, the advent of cryptocurrencies has led to the emergence of ransomware attacks that extort organizations by encrypting critical data and demanding for ransom payments in untraceable cryptocurrencies.

The primary role of Toronto Hydro's cyber security practice is to maintain a strong cyber security posture through a combination of sustaining existing systems and enhancement initiatives, commensurate to the perceived threat level and the organization's risk tolerance.

The utility sustains existing systems with the maintenance and organic and strategic growth of existing information security capabilities. From the threat, risk and compliance 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 and malware protection software. The identity access management aspect of the program ensures that the organization maintains secure, role-based access to resources, and proper logging for audit and forensic analysis purposes.

Toronto Hydro's enhancement initiatives expand baseline cyber security capabilities through the adoption of advanced threat protection technologies and user education processes aimed at curbing

[1] The internet of things (IoT) refers to the interconnected network of physical devices, vehicles, home appliances, and other items embedded with electronics, software, sensors, and connectivity which enables these objects to collect and exchange data. The IoT allows these devices to communicate with each other and with a centralized system, enabling them to perform a wide range of tasks and functions without human intervention

the exposure to social engineering attacks. The utility explores pioneering technologies and cyber defence mechanisms to ensure the security of its digital assets and safeguard the privacy of customer and employee personal information and gain stakeholder confidence.

Pursuant to the Strategy, Toronto Hydro requires all systems delivered through sustainment, enhancement, and transformation initiatives beyond cyber security-specific initiatives, to meet stringent standards that are aligned with the Ontario Energy Board Cyber Security Framework and stipulated within the utility's application security, network security, cloud security, data security and endpoint security standards. This ensures a strong cyber security posture for every system deployed within or for Toronto Hydro.

D8.5 IT Investment Planning Process

IT investment planning is the process of developing, prioritizing, and managing a continuous five-year roadmap of investments, including a detailed project plan for the first year. As part of the Strategy, Toronto Hydro developed an 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. The capital and cloud (OM&A) expenditures detailed in Exhibit 2B, Section E8.4 and Exhibit 4, Tab 2, Schedule 17, reflect the roadmap for the next rate period.

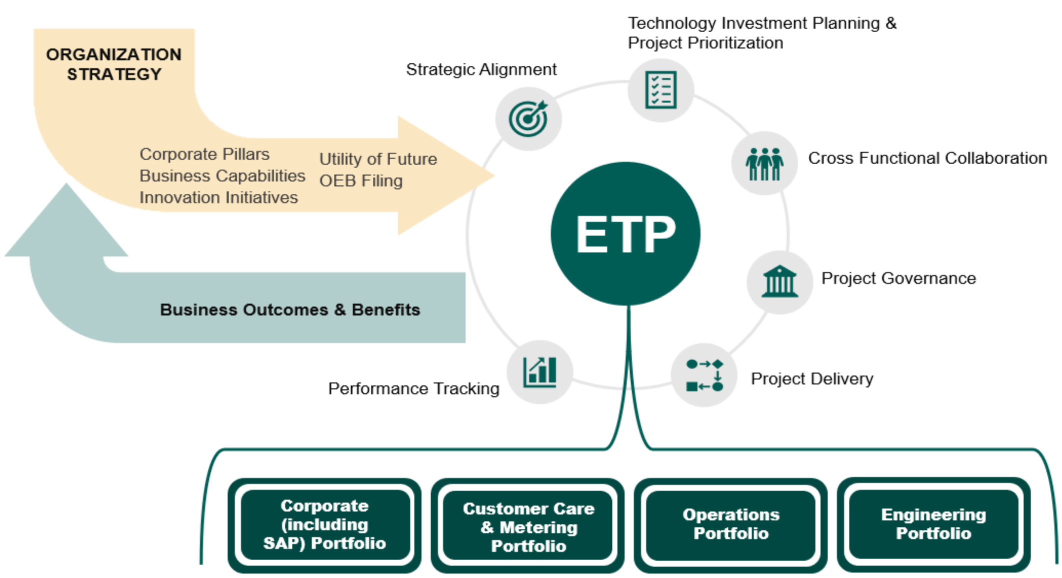

Figure 3: Enterprise Technology Portfolio Framework

D8.5.1 Enterprise Technology Portfolio (ETP) Framework

Through the ETP framework, the utility centralizes the intake of all technology requests from across the organization, plans IT investments and prioritizes initiatives and projects in accordance with the Strategy. In prioritizing initiatives and projects, the utility considers:

- Operational factors such as IT asset lifecycle, business impacts, change management, resource availability, and internal and external project dependencies.
- Financial factors such as costs versus benefits and approved budgets
- External factors such as IT industry best practices and trends, utility industry trends, vendors' information, and trends of evolving regulatory and compliance requirements are also taken into consideration as needed.
- Strategic alignment with key investment priorities and objectives established through the utily's integrated planning process detailed in Section E2.

Based on these inputs, ETP roadmaps are designed with the following objectives:

(i) Enabling technology investments that advance business and customer outcomes;
(ii) Ensuring optimal levels of IT system reliability and availability; and
(iii) Compliance with the utility's IT standards.

Each roadmap includes a detailed plan for the first year and provides a higher-level plan for the remaining period. This agile approach provides necessary certainty and precision for the implementation of near-term initiatives, and high-level parameters for longer-term initiatives, giving the utility the ability to respond effectively to changes in external drivers and risks, such as:

(i) Fluctuations in software and hardware costs;
(ii) Changes in the release dates of certain applications;
(iii) New technology products disrupting the marketplace and industry;
(iv) New threats, vulnerabilities, or modes of cyber security attacks;
(v) New or evolving requirements from regulatory bodies such as the Ontario Energy Board, Measurement Canada and the Independent Electricity System Operator (IESO); and
(vi) Changes in industry best practices such as the adoption of cloud solutions.

Toronto Hydro maintains a flexible and agile approach by continually balancing its roadmap against the strategic objectives of the organization for the planning period. For example, to support grid modernization during the 2025-2029 rate term, Toronto Hydro intends to prioritize projects that enable monitoring and operational capabilities of its distribution system. Examples of such efforts will include installing enhanced communication infrastructure, introducing advanced grid configurations, enabling enhanced monitoring, automation and remote control, and providing greater insight into the grid operations through analytics into grid performance and grid reliability. For more information on these types of investments, please refer to the Grid Modernization Strategy at Exhibit 2B, Section D5 and the Advanced Distribution Management System Business Case in Exhibit 2B, Section E8.4, Appendix A.

D8.5.2 Project Governance Framework

Beyond the ETP framework, the utility relies on a formal business case for the governance and approval for projects within the one-year window. Stakeholders from various functions in the organization collaborate in the creation, review, and approval of each business case. This process includes business units, IT functional and technical teams, IT security teams and change management professionals. Stakeholders' inputs determine the scope, business requirements, current state business processes, future state business processes, options analyses, the preferred approach and the associated costs and benefits. Once the business case is approved, the project proceeds to execution. Toronto Hydro uses a robust project management framework to manage and oversee the progress of the project against key parameters such as the approved budget, scheduled, scope, identified risks and target benefits.

D8.5.3 Evaluation of Options

With the emergence and increasing availability of cloud-based solutions, Toronto Hydro deploys the Strategy to evaluate multiple options to meet business needs, including cloud-based solutions such as software-as-a-service, platform-as-a-service, and infrastructure-as-a-service. For each project, the utility grounds its investment decisions on a rigorous and consistent comparison and evaluation of on-premise and cloud-based solutions, with reference to various criteria such as: transformation potential, rollout velocity, the size of the solution, the business criticality of the underlying functions, data and cyber security considerations, the flexibility of adopting new features, the window of available vendor maintenance, and the total cost of ownership.

For example, when considering projects implemented in 2020-2024 for critical grid management systems, such as Network Management Systems, Toronto Hydro completed a detailed analysis and determined that the on-premise solution in these cases provided the optimal outcomes. This decision was based on the business criticality of these systems in managing the grid and the high degree of sensitivity to cyber security risks. Another key factor that informed the utility's decision was the need for flexibility in maintenance windows to avoid operational interruptions due to unplanned events such as storms.

In a different example, Toronto Hydro implemented a cloud-based solution to support its enterprise health and safety business processes. The utility selected this solution over any available on-premise alternatives because unlike on-premise alternative, the selected cloud-based solution required limited integration to other Toronto Hydro systems and offered the ability to adopt new industry best practices in a shorter period of time. From a cyber security standpoint, the selected solution does not house sensitive health and safety information, which limits the risk exposure to an acceptable level. From a financial standpoint, the utility determined that the total cost of ownership for the cloud solution would be lower than the implementation of a comparable on-premise solution. Cumulatively, these considerations led Toronto Hydro to select a cloud-based solution to support its enterprise health and safety processes.

Toronto Hydro Enterprise IT Cost Benchmark & Functional Maturity Assessment

Final Report

June 5, 2023

Engagement Number: 330079917

Gartner®

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Summary of Findings

Gartner®

TH's 2022 IT spend as a % of Revenue has increased since 2017, however is very similar to the peer group average; higher spend levels are due to inflation, investments in digital transformation and maturing IT's capabilities

- Toronto Hydro was compared to a peer group of eight utility organizations with similar revenue and operating expenses, with a major focus of electricity distribution in major urban centers
- Toronto Hydro's 2022 IT Spending as a % of Revenue was 3.2% compared to an average of 3.0% for the peer group, and 3.3% of OpEx compared to 3.9% for the peer group. The $28 million IT spending increase in 2022 over 2017 was due to inflation (~$10 million), increasing Operational Expenses (i.e. ERP support, cloud services, cyber security) and investments in the Customer Information System.
- Increase in IT Spending over 2017 is similar to industry peers
- In 2022, Toronto Hydro allocated 11% of IT Spending to "transform", almost three times more than in 2017. This is the result of investments in digital transformation.
- Toronto Hydro's IT staffing levels are materially lower than the peer group average (5.8% IT FTEs as a % of total Employees** versus 8.2%). IT Staffing levels as a % of total Employees** has decreased slightly from 6.2% in 2017.

Metric	Toronto Hydro (2022)		Toronto Hydro (2017*)		Peer Group Average (2022)	ITKMD Utility Industry (2022)
	% Spend	$ Spend (millions)	% Spend	$ Spend (millions)	% Spend	% Spend
IT Spend as a % of Revenue						
- Operational	1.5%	$55.2	1.0%	$39.2	1.8%	2.0%
- Capital	1.7%	$59.6	1.2%	$47.9	1.2%	1.0%
- Total	3.2%	$114.8	2.2%	$87.1	3.0%	3.0%
IT Spend as a % of OpEx						
- Operational	1.6%	$55.2	1.1%	$39.2	2.3%	2.4%
- Capital	1.7%	$59.6	1.3%	$47.9	1.6%	1.3%
- Total	3.3%	$114.8	2.4%	$87.1	3.9%	3.7%
Run, Grow, Transform*** (% of total IT Spend)						
- Run %	71%	$81.1	71%	$61.8	65%	70%
- Grow %	18%	$21.2	25%	$21.8	20%	18%
- Transform %	11%	$12.4	4%	$3.5	15%	12%
- Total	100%	$114.8	100%	$87.1	100%	100%
IT FTEs as a % of Employees**	5.8%		6.2%		8.2%	6.8%

* Toronto Hydro's 2017 data has not been adjusted for inflation (2017 inflation adjusted spend @ 2.1%[1] year over year would = $97 M)
** This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors
*** See page 31 for "Run, Grow, Transform" definitions
[1] Average Canadian Consumer Price Index increase 2017-2022
Note: Totals may not equal due to rounding

Gartner

TH's focus on digital transformation has meant a higher allocation to applications spending; IT spending by cost category is balanced and in line with peer organizations

- Overall allocation to Applications spending is more than the peer group (51.2% of IT spend versus 41.9%). This is normal during a period of growth and transformation. Applications spending is the largest contributor to the overall increase in IT spending when compared with 2017, up $18 million. This can be largely attributed to Customer Information System upgrades.

- The allocation to IT Management & Administration (which includes Governance & Service Management, IT Security, IT Operations Management and Service Continuity / Disaster Recovery) was 14.8%, compared to 10.8% for the peer group. Increased investment in Cyber Security services and capabilities is the main reasons for this variance.

- Allocation to both hardware (14.1% of IT spending in 2022) and software (31.1% of IT spending in 2022) is virtually the same as the peer group.

- Toronto Hydro relies less on Outsourcing (21.3% of IT spend in 2022) than the peer group (26.6%). This is balanced by a higher allocation to Personnel (33.4% of IT spend in 2022) as compared with the peer group (26.6%).

Metric	Toronto Hydro (2022)		Toronto Hydro (2017*)		Peer Group Average (2022)	ITKMD Utility Industry (2022)
	% Spend	$ Spend (millions)	% Spend	$ Spend (millions)	% Spend	% Spend
IT Spend Distribution by Area						
- Enterprise Computing	14.7%	$16.9	25.0%	$21.8	14.6%	15%
- Voice & Data Network	9.5%	$10.9	9.5%	$8.3	19.8%	12%
- Workplace Services	6.9%	$7.9	6.1%	$5.3	9.2%	7%
- IT Service Desk	3.0%	$3.4	2.3%	$2.0	3.8%	3%
- Application Development	24.7%	$28.4	46.9%[2]	$40.8	18.9%	25%
- Application Support	26.5%	$30.4			23.0%	21%
- Governance & Ser. Mgmt.	5.9%	$6.7	10.3%[3]	$9.0	4.6%	8%
- IT Security	5.7%	$6.5			2.4%	4%
- IT Ops. Mgmt.	2.8%	$3.2			3.2%	3%
- Ser. Con't / DR	0.4%	$0.5			0.6%	1%
- Total	100%	$114.8	100%	$87.1	100%	100%
IT Spend per Cost Category						
- Outsourcing	21.3%	$24.4	19.9%	$17.3	26.6%	26.0%
- Personnel	33.4%	$38.4	39.8%	$34.7	26.6%	31.0%
- Software	31.1%	$35.7	27.6%	$24.0	31.9%	30.0%
- Hardware	14.1%	$16.2	12.7%	$11.1	14.9%	13.0%
- Total	100%	$114.8	100%	$87.1	100%	100%

* Toronto Hydro's 2017 data has not been adjusted for inflation (2017 inflation adjusted spend @ 2.1%[1] year over year would = $97 M)

[1] Average Canadian Consumer Price Index increase 2017-2022

[2] 2017 Application Development includes Application Support

[3] 2017 Governance & Service Mgmt. includes IT Security, IT Ops Mgmt. and Service Continuity / Disaster Recovery

Note: Totals may not equal due to rounding

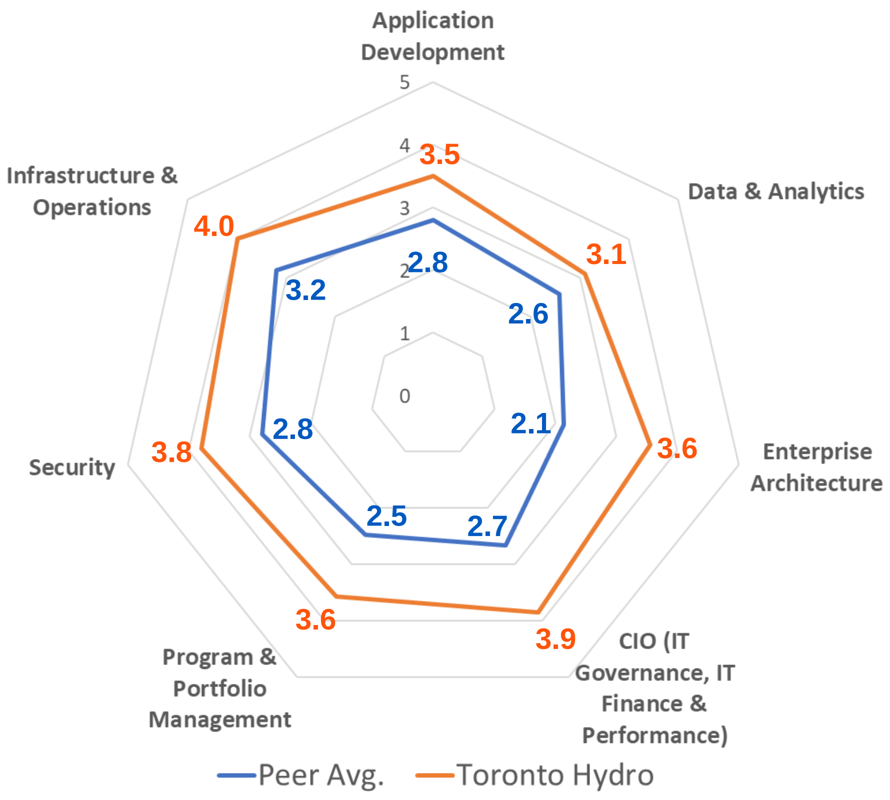
The IT capability assessment showed that Toronto Hydro's maturity across all domains is slightly higher than peers

- Toronto Hydro was compared to a peer group of 9 to 14 organizations (depending on data available for each IT domain) from the energy and utility industry with revenues between $1 billion and $3 billion USD
- 64 functional activities across 7 IT domains were assessed by comparing Toronto Hydro's current state (as defined by IT domain leadership) to Gartner's best practices.
- Toronto Hydro's overall IT maturity was 3.6 compared to 2.7 for the peer group. Higher levels of maturity were seen across all domains included in the scope of the assessment. This reflects Toronto Hydro's focus and investment in maturing IT capabilities.
- Within Toronto Hydro, Infrastructure & Operations (I&O) was the most mature domain at 4.0 and Data & Analytics (D&A) was the least mature at 3.1. I&O is a well-established domain whereas D&A is relatively new, hence these results are not surprising.
- Steady efforts have been made to improve capabilities within the Program & Portfolio Management, Enterprise Architecture and IT Security domains.
- Assessing maturity results relative to peers is interesting, however, comparing current maturity levels with how important the capability is for the organization to achieve its overall objectives is more important (see next page).

IT Domain Maturity Levels

Toronto Hydro's Overall IT Maturity Level: 3.6

Peer Maturity Level: 2.7



Maturity scores are assessed on a scale from 1-5, with the score of 5 representing Gartner's best practices for the IT domain

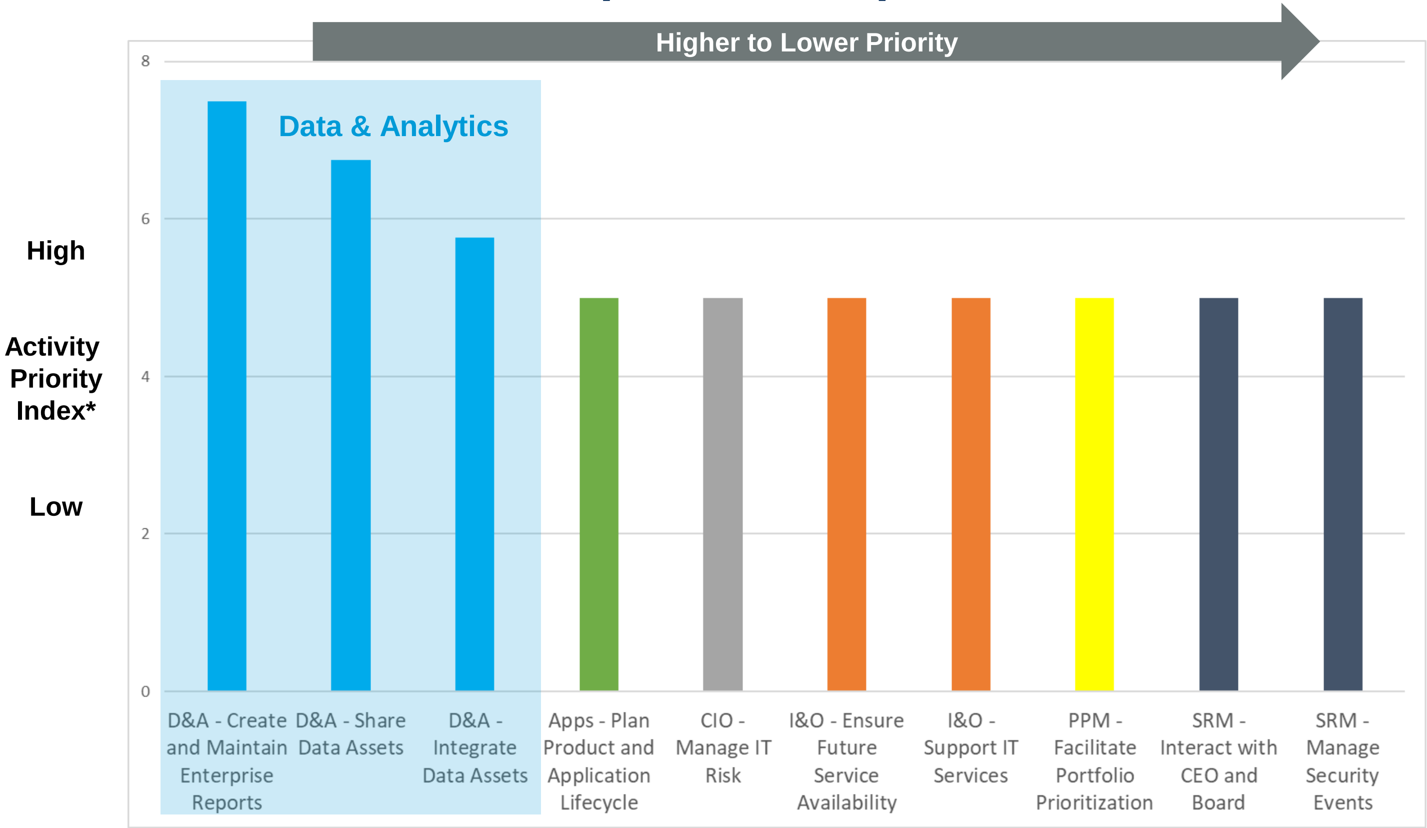
Gartner

Based on maturity assessment results, opportunities for improvement exist in each domain, however improving Data & Analytics capabilities would add the most value to Toronto Hydro

- 38 of 64 functional activities had a positive Activity Priority Index meaning there is value to Toronto Hydro in improving the capability
- Each in-scope domain had a number functional activities identified for improvement:
  - Chief Information Officer (CIO)[1] = 7
  - Applications = 3
  - Data & Analytics = 5
  - Enterprise Architecture = 5
  - Infrastructure & Operations = 5
  - Program & Portfolio Management = 7
  - IT Security = 6
- When relative importance is considered, improvements to the maturity of the Data & Analytics domain would add the most value to Toronto Hydro

[1] includes Managing IT Governance, Managing IT Finance and Managing Performance

Top 10 Areas for Improvement



***Activity Priority Index: Activity Priority Index (API) for an activity is computed as importance minus maturity multiplied by its importance. A higher API score indicates a greater priority for improvement to the organization.**

02 Objectives and Approach

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Gartner understanding of business context and objectives

Context

- Toronto Hydro wanted an independent and objective expert assessment of process maturity of its IT functional areas and to establish a reliable baseline of its overall IT spend and staffing position relative to comparable peer organizations.
- In the short-term, these maturity and cost baseline assessments would provide a fact-based action plan for the organization's regulatory filing and catalyze a roadmap of initiatives that Toronto Hydro's IT Leaders will drive to advance maturity and efficiency levels consistent with Toronto Hydro's Business and IT strategic objectives.
- Longer term, these maturity and cost baseline assessments would form the basis for a transformational strategy as a result of the current state baseline and recommendations of this annual effort.
- Gartner's insights and recommendations will highlight IT capabilities needed for Toronto Hydro to align to existing organizational strategies, increase the pace of value being brought to the business, and enable the promise for future transformational aspirations.

Engagement Objectives

Gartner combined several unique and proprietary Gartner assets and capabilities that give Toronto Hydro a fact-based, objective starting point for its ongoing strategic direction. These capabilities include:

- Gartner Research maturity models aligned to key capability areas that integrate Gartner Research insights and industry leading frameworks to support maturation objectives.
- Gartner's world-leading IT Benchmark database to support a fact-based comparison, using a custom-built peer group to Toronto Hydro's environment, to anchor the current state in key IT enterprise-level cost and staffing measures.

Outcomes of the engagement will include:

- A current state summary of Toronto Hydro's maturity across the organization
- A current state summary of Toronto Hydro's IT spend and staffing levels relative to peers with a comparable environment that will identify optimization opportunities to focus future strategic efforts.
- A set of prioritized recommendations based on the comparative analysis that will advance Toronto Hydro in areas directly impactful to the to IT and business objectives.
- Guidance on appropriate re-measurement periods and the foundation to measure progress objectively.

Gartner

Gartner conducted an IT assessment that included a review of process maturity of key IT functions and an enterprise-level benchmark of IT spend and staffing relative to peers

PROCESS MATURITY

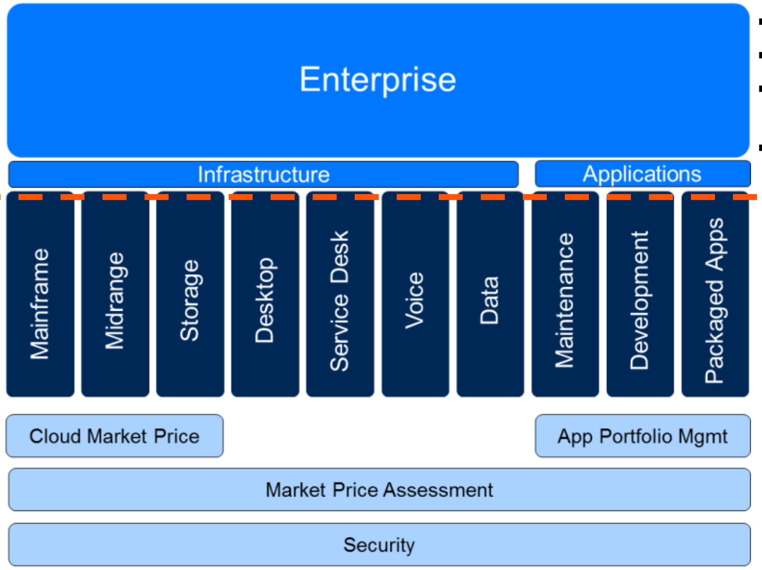
Current State Assessment of IT Process Areas:

- CIOs (IT Governance, IT Finance, Performance Mgmt.)
- Applications
- Data & Analytics
- Enterprise Architecture & Technology Innovation
- Infrastructure & Operations
- Program & Portfolio Management
- Security & Risk Management

+

Scope of Assessment

SPEND AND STAFFING



- IT$ / Rev
- IT$ / Opex
- IT FTEs / FTE
- Run/Grown / Transform

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03
Enterprise IT Spending & Staffing Analysis

3.1
IT Spending & Staffing Benchmark – Methodology Overview

Toronto Hydro's IT Assessment focuses on process maturity and spending and staffing as compared to peer organizations

Section 3.0 Focus

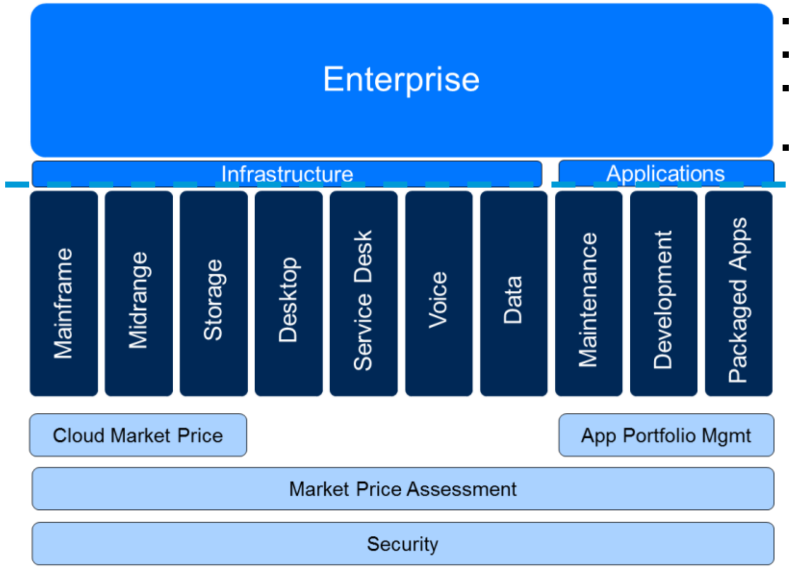
PROCESS MATURITY

Current State Assessment of IT Functional Areas:

- CIOs (IT Governance, IT Finance, Performance Mgmt.)
- Applications
- Data & Analytics
- Enterprise Architecture & Technology Innovation
- Infrastructure & Operations
- Program & Portfolio Management
- Security & Risk Management

+

SPENDING AND STAFFING



- IT$ / Rev
- IT$ / Opex
- IT FTEs / FTE
- Run/Grow / Transform

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Spending & Staffing Benchmark Methodology Overview

Gartner used its industry-leading benchmarking consensus models to evaluate total IT Spending and Staffing relative to a hand selected group of industry peers and IT Key Metrics Data for the Utilities industry.

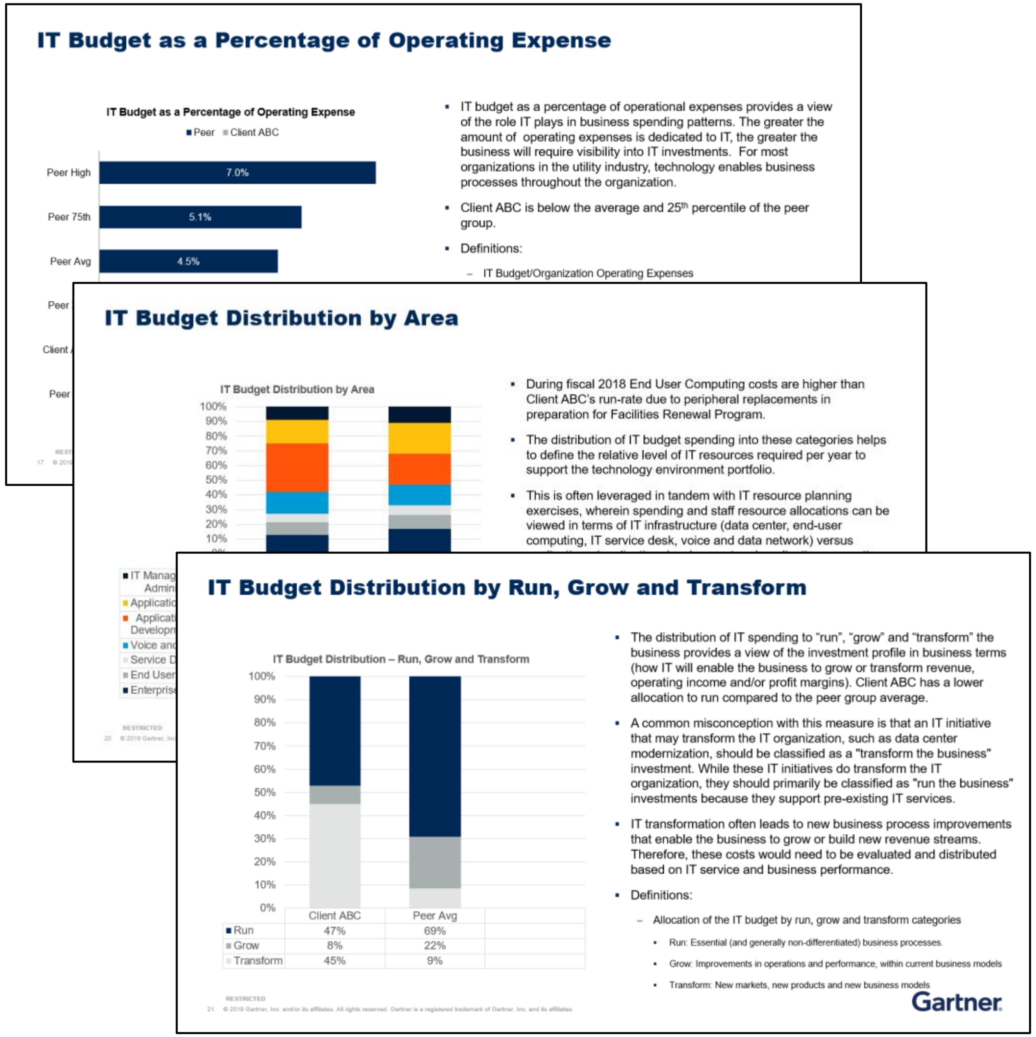
The Enterprise View: IT Spending and Staffing Assessment analysis will provide and compare the following metrics:

Spending Measures

- IT Spending as a % of Revenue
- IT Spending as a % of Operating Expense
- IT Spending Per Employee
- Capital vs. Operational Spending
- Run vs. Grow vs. Transform Spending
- Distribution of IT Spend—Hardware, Software, Personnel, Outsourcing, Other
- Distribution of IT Spend—by IT Function

Staffing Measures

- IT Staff as a % of Company Employees
- Distribution of IT Support—by IT Function



3.2
Enterprise IT Spending & Staffing Benchmark Results

Analysis Notes

- Toronto Hydro's data submission for this benchmarking engagement includes:
  - 2022 actuals for Revenue, Operating Expenses and Total Employees
  - 2022 actuals (January to December) for IT Spending & Staffing

- 2017 Toronto Hydro & Peer IT Spending & Staffing data was taken from Gartner's "IT Budget Assessment Final Report" dated March 16, 2018

- Peer Group data is from 2020-2022

- Gartner's IT Key Metrics Data (ITKMD)* is from 2021

* ITKMD is a Gartner Benchmark Analytics solution that delivers indicative IT metrics in a published format as directional insight for IT organizations. This solution represents a subset of the metrics and prescriptive capabilities that is available through Gartner Benchmark Analytics.

Peer Group Profiles

Selection Criteria	
Primary Criteria	Utilities Industry
Secondary Criteria	Nature of Business (electricity focused, includes distribution within major centers), Total Revenue, Total Operating Expenses, # of Employees and Geography

Custom Peer Group Profile		
Number of Organizations	8	
Geographical Location	Canada, USA, Europe, South America, Australia, New Zealand	
	Toronto Hydro*	**Peer Group Average**
Total Revenue	**$3.60 Billion**	**$3.63 Billion**
Total Operating Expense	**$3.48 Billion**	**$3.08 Billion**
Total Employees	**1,245**	**2,890**

2021 IT Key Metrics Data (ITKMD) Utilities
123
Utilities
Global
2021 ITKMD

* Toronto Hydro data is for fiscal year ending December 31, 2022
** All analysis is in Canadian dollars, using the exchange rate of 1 USD = 1.277 CAD

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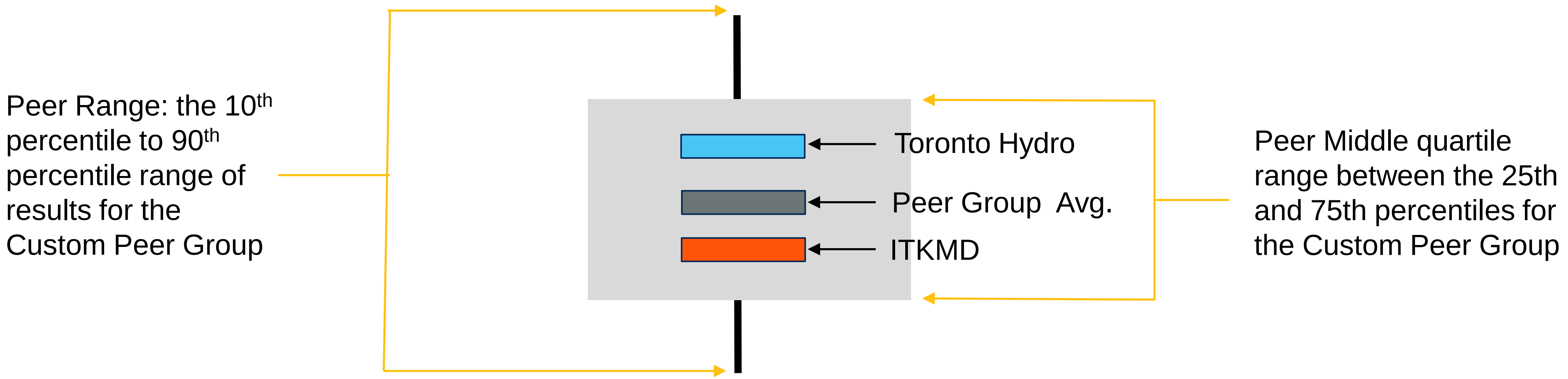
Benchmark Analysis Methodology
Peer Comparisons

Toronto Hydro's results are displayed in comparison with the following reference points:

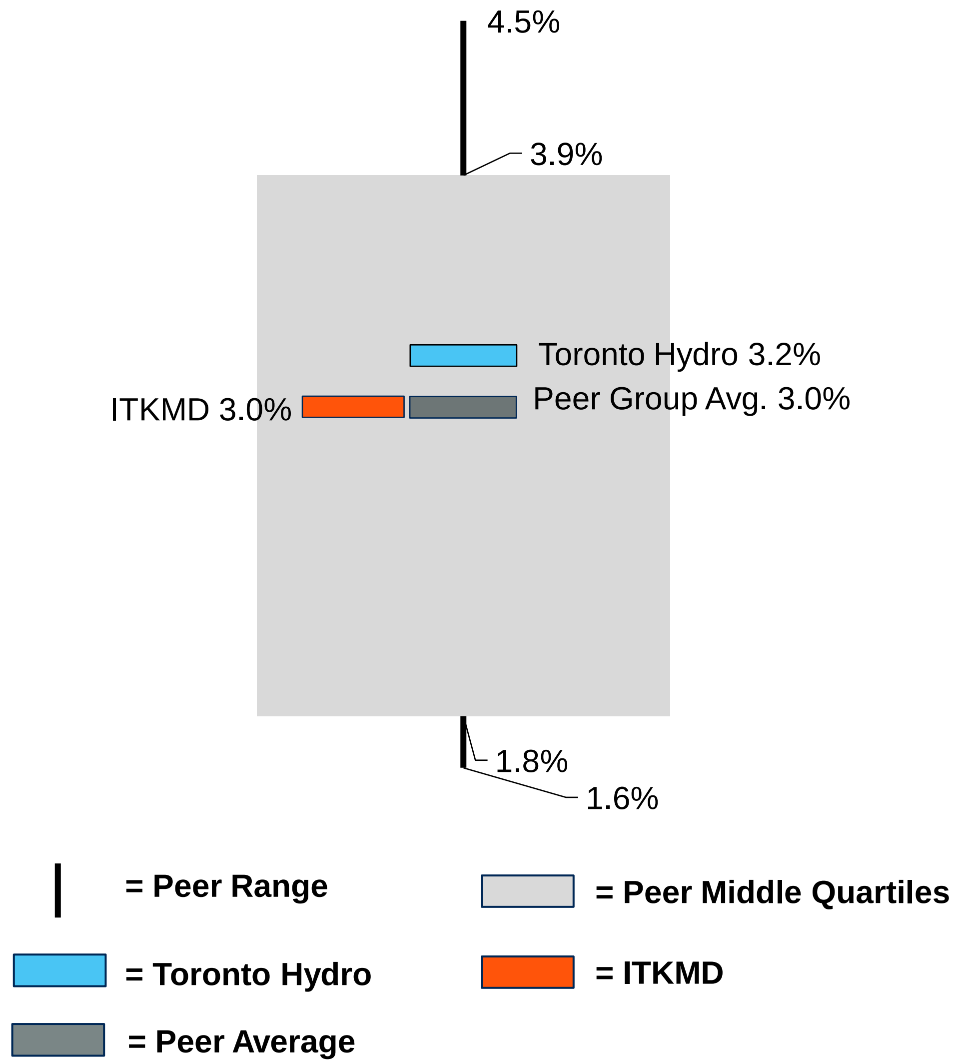


There are not necessarily "good" or "bad" results for any individual metric.

Differences in spending and staffing metrics derived from this analysis provide insight into current strategic IT investment levels versus your competitive landscape.

These measures should also be considered within the context of your future state organizational objectives.

IT Spend as a Percentage of Revenue



Observations

- TH's 2022 IT Spending is a % of Revenue was 3.2% compared to an average of 3.0% for the peer group. This represents a spend level that is very similar to the peer group and ITKMD for Utilities organizations.

Description	• IT spending as a percentage of revenue provides a view of the role IT plays in the spending patterns of the organization. The greater the amount of the operational expenses that is dedicated to IT, typically the greater need for visibility into the IT investments the organization will require.	
Definition	IT Spending includes capital and operations spending for technology during the study period, including labour, software, hardware, telecommunications expenses; includes project spending	
Calculation	IT Spend / Revenue	**Toronto Hydro: $114,759,546 / $3,601,700,000**

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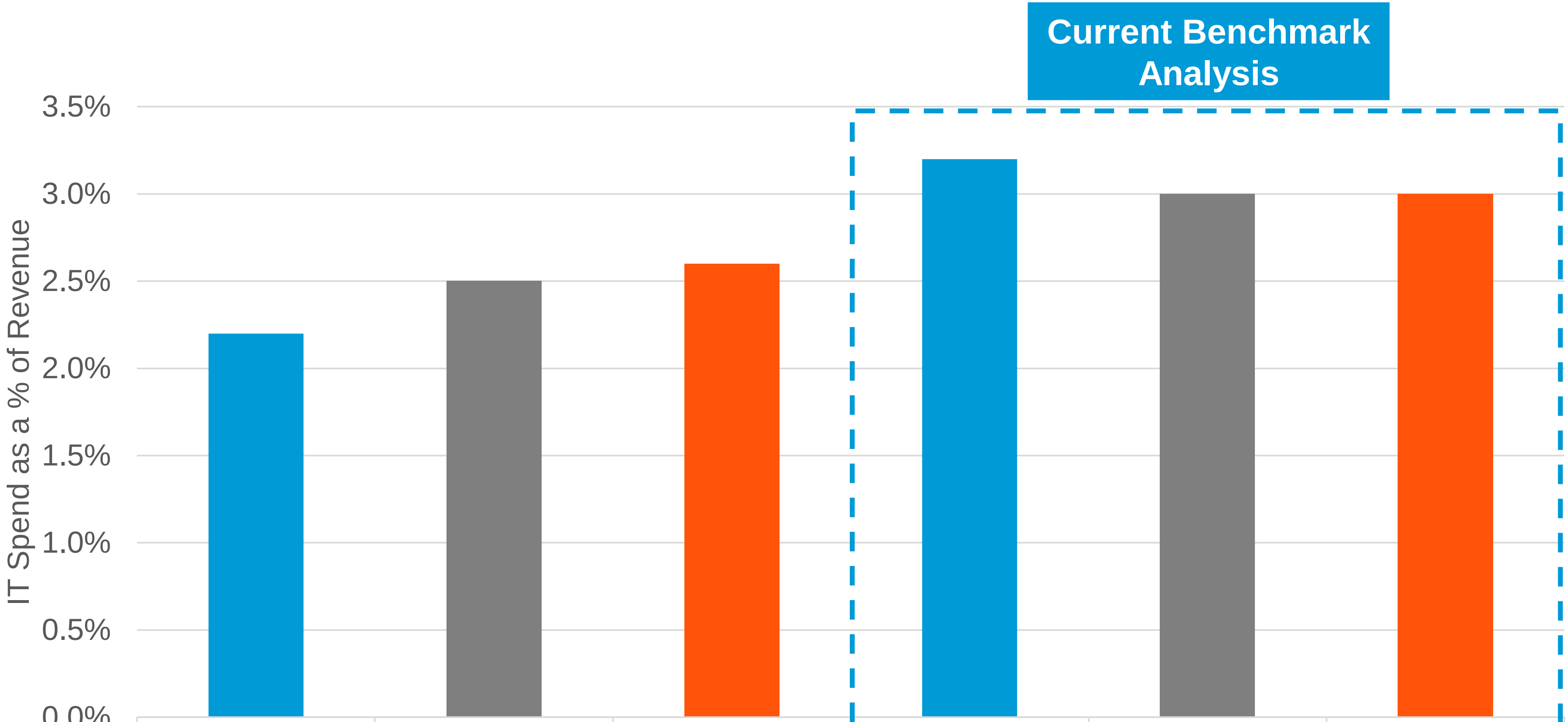
IT Spend as a Percentage of Revenue – Multi Year View



TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
2.2%	2.5%	2.6%	3.2%	3.0%	3.0%

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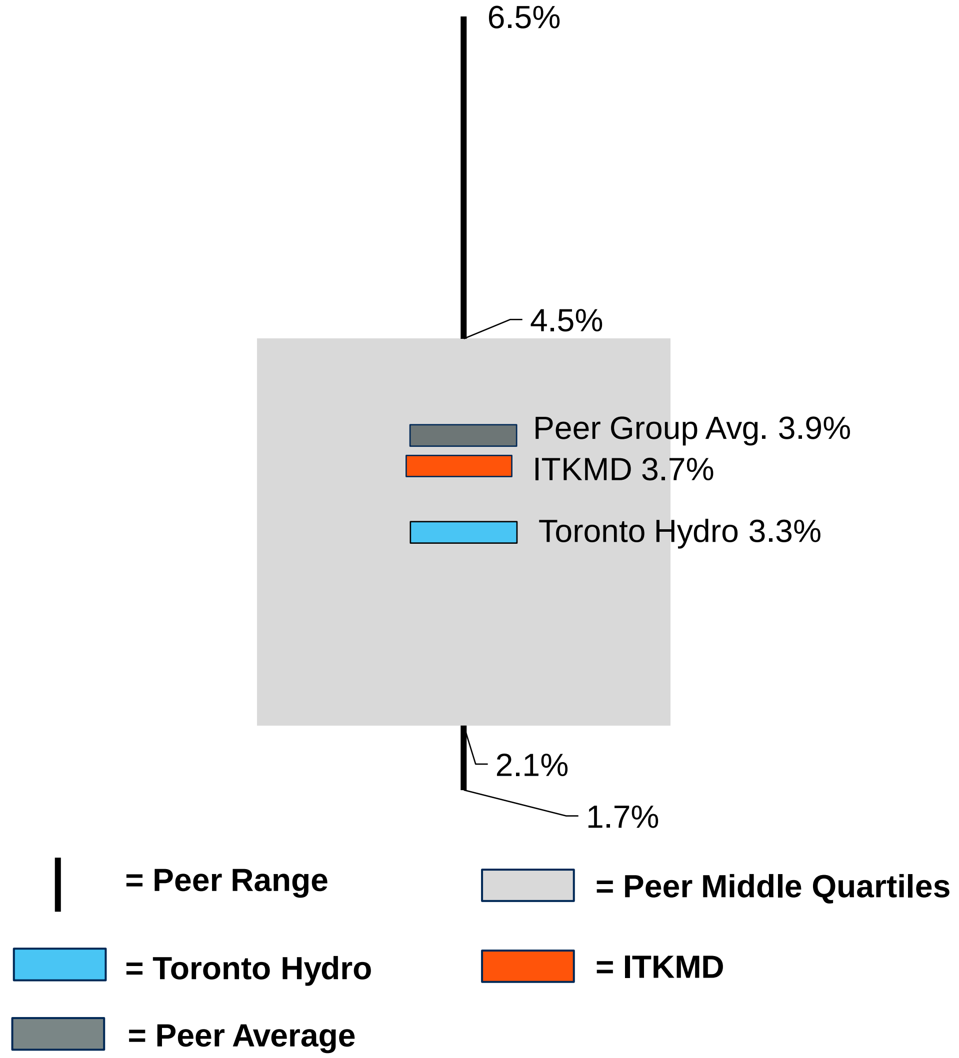
IT Spend as a Percentage of Operational Expense

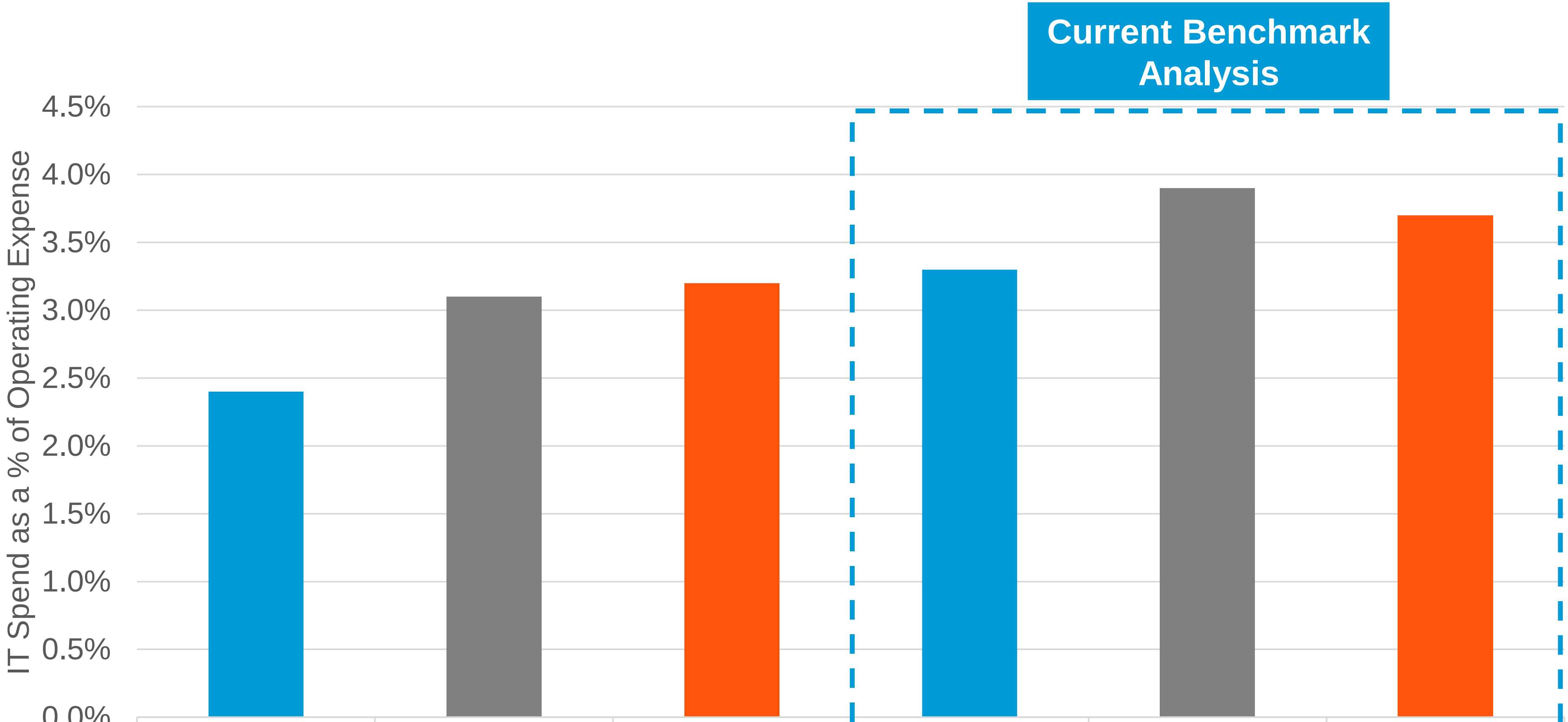


Observations

- TH's 2022 IT Spending as a % of Operating Expense was 3.3% compared to an average of 3.9% for the peer group. This represents a spend level that is very similar to the peer group (15% less) and ITKMD for Utilities organizations (11% less).

Description	• IT spending as a percentage of operational expenses provides a view of the role IT plays in the spending patterns of the organization. The greater the amount of the operational expenses that is dedicated to IT, typically the greater need for visibility into the IT investments the organization will require.	
Definition	IT Spending includes capital and operations spending for technology during the study period, including labour, software, hardware, telecommunications expenses; includes project spending	
Calculation	IT Spend / Operational Expense	**Toronto Hydro: $114,759,546 / $3,348,600,000**

IT Spend as a Percentage of Operating Expense – Multi Year View



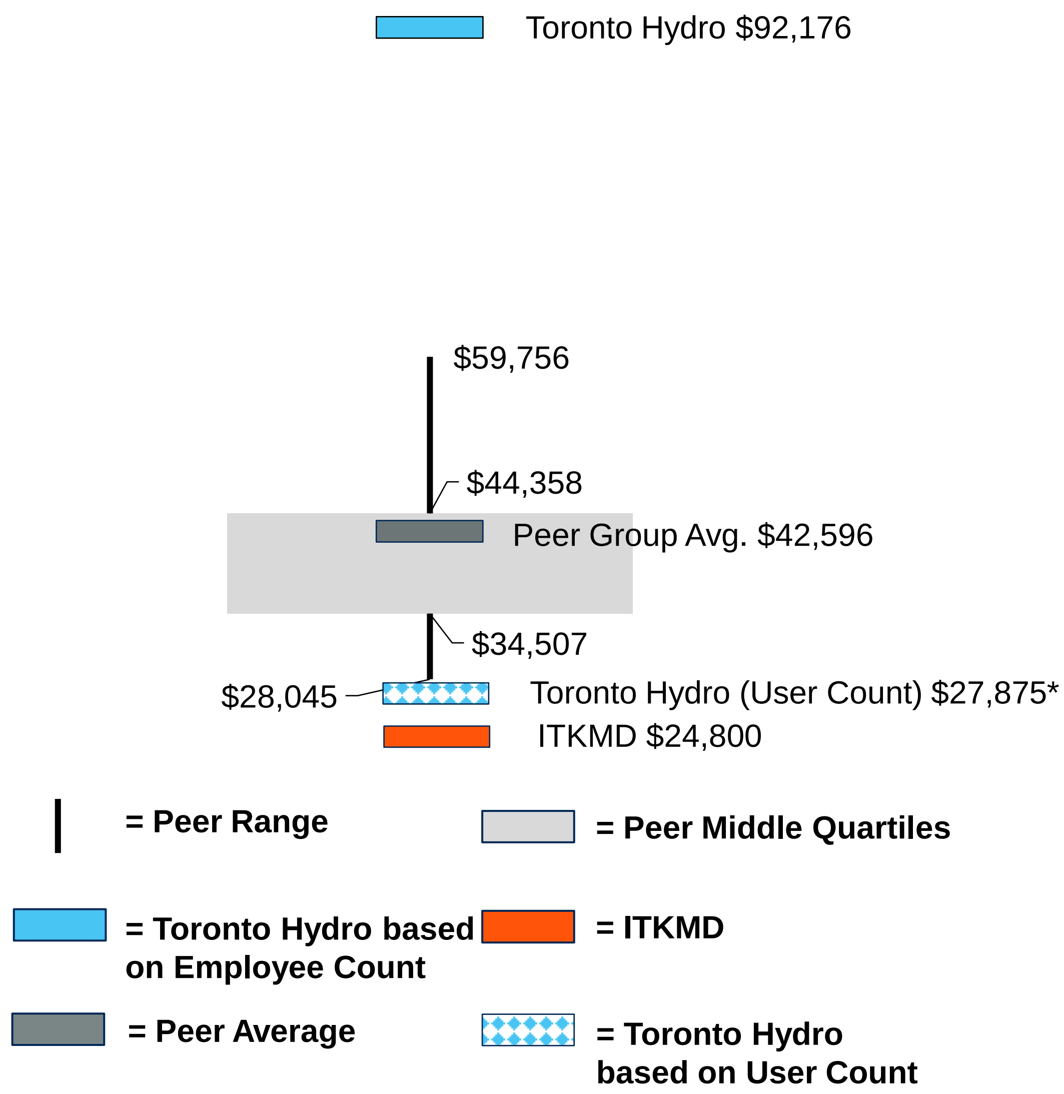
TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
2.4%	3.1%	3.2%	3.3%	3.9%	3.7%

Gartner

Employees versus Users at Toronto Hydro

- Gartner typically collects the number of employees for an IT Enterprise Benchmark and bases two standard metrics on employee count: IT Spending per Employee and IT FTEs as a Percentage of Employees.
  - Many of the IT departments Gartner works with, and has in our peer benchmark database, typically do not know the number of contractor labour or level of outsourcing in the lines of business, and Gartner does not normally collect a number of users.
- As with other measures comparing IT spending to business measures, these two metrics can be influenced by both the numerator and denominator.
- For TH, these two metrics appear to be skewed compared to the peer group when based on the employee count.
- As a test of this assumption, Gartner focused the analysis using TH number of Users rather than Employees and compared results.
- While metrics based on Employees are 116% to 133% more than the peer group, the results based on Users are between 29% and 35% less than the peer group.
  - The metrics based on Users are in line with the other metrics (IT Spending as a Percentage of Revenue and Operational Expense), supporting the assumption that it is TH employee count, not IT spending or staffing that drives the results on slides 24 and 26.

IT Spend per Employee



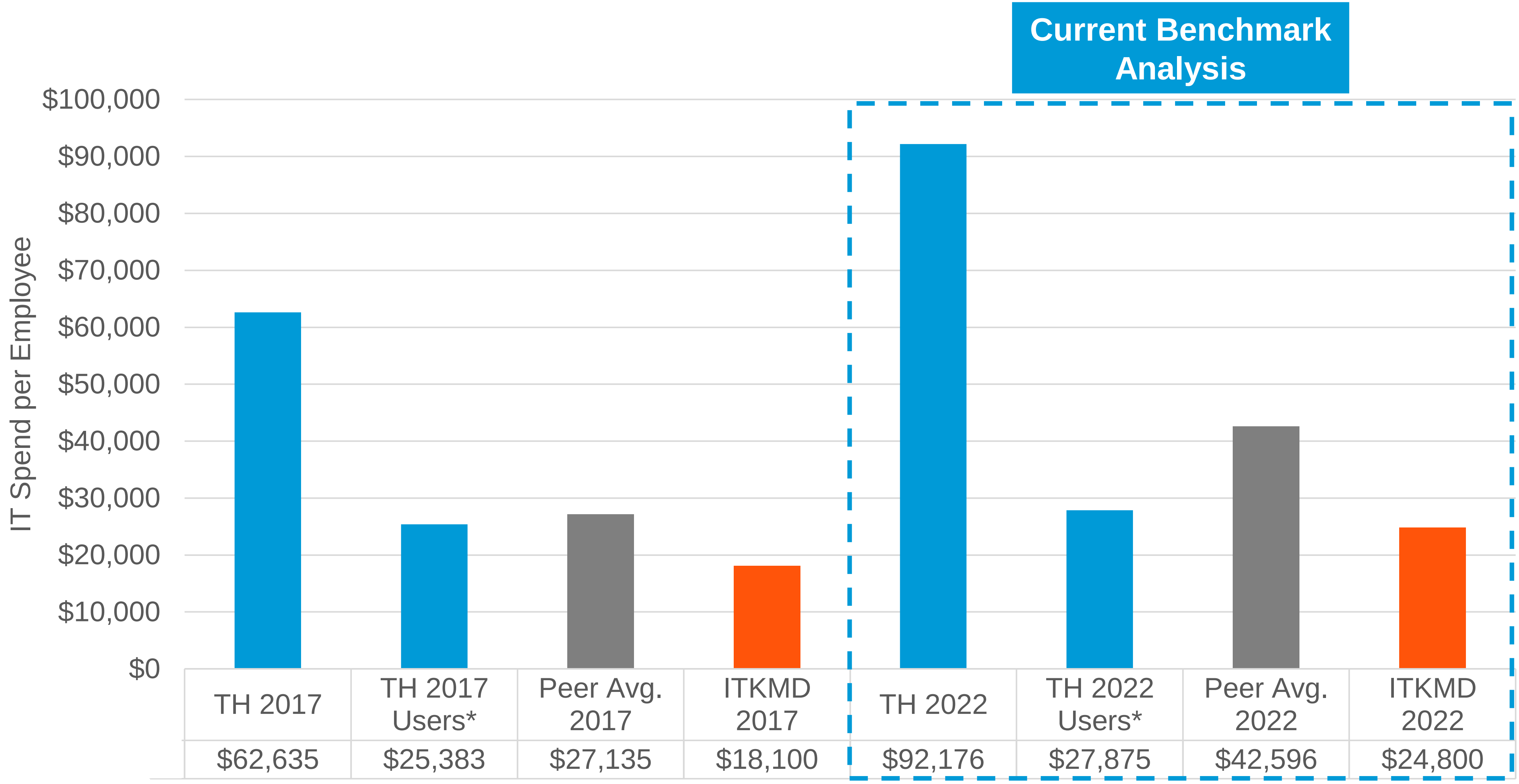
Observations

- IT Spend per User for TH is 35% less than the peer group average of $42,596, and similar with the ITKMD average for the utilities industry
- Given TH's usage of contract employees, Gartner has used the IT spend per User metric rather than IT spend per Employee

Description	• IT spending per employee provides insight into the amount of technology support an organization's workforce receives. • High spending can imply higher levels of automation and/or higher investment in IT in general. Low spending levels can be related to higher overall staffing levels and or lower IT investment than peers. • Large variations within industry groups can represent different business models for service or product delivery.	
Definition	IT Spending includes capital and operations spending for technology during the study period, including labour, software, hardware, telecommunications expenses and includes project spending. Organization Employees includes staff, exclusive of Contractors.	
Calculation	IT Spending / Organization Employees	**Toronto Hydro: $114,759,546 / 1,245**

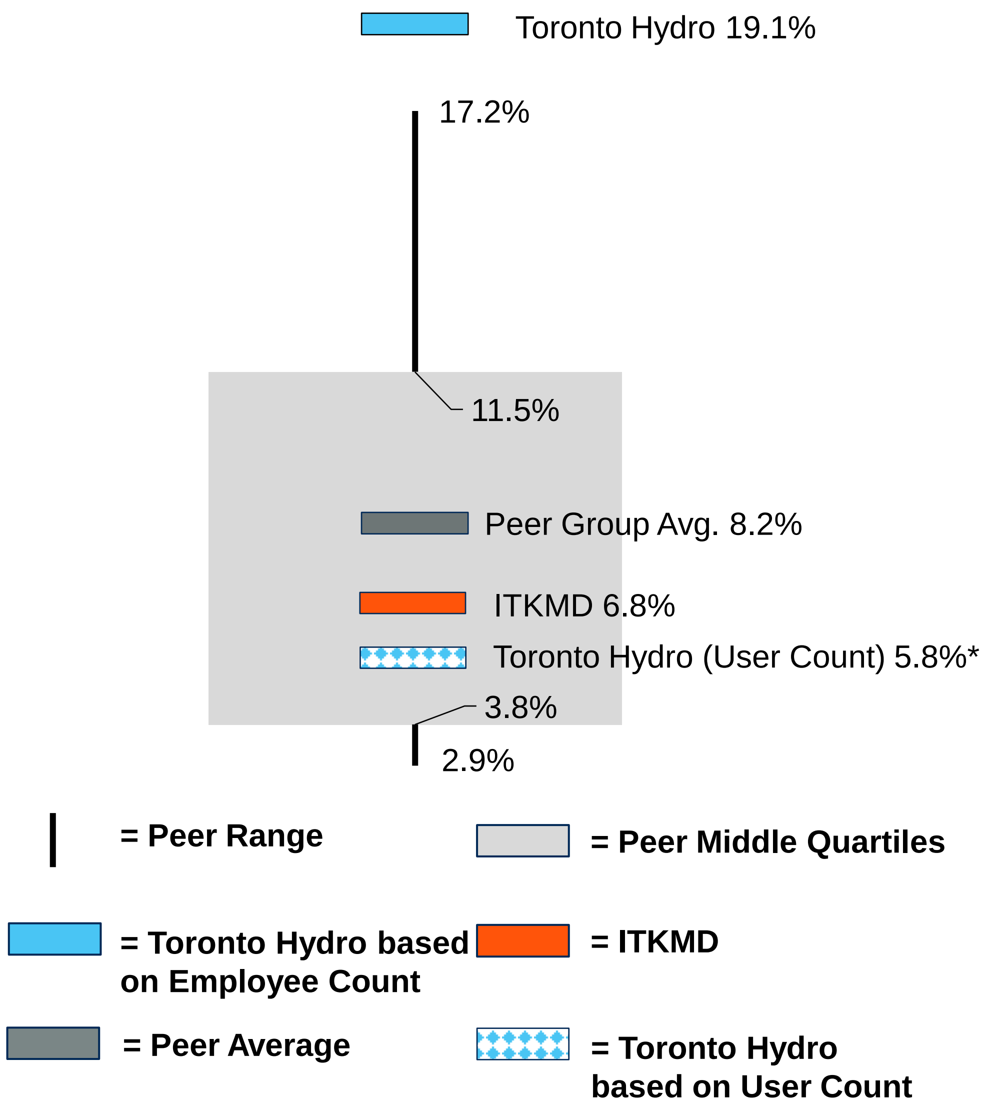
* Gartner's benchmarking definition for "employees" does not include contractors. This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors.

IT Spend per Employee – Multi Year View



* Gartner's benchmarking definition for "employees" does not include contractors. This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors.

IT FTEs as a Percentage of Total Employees



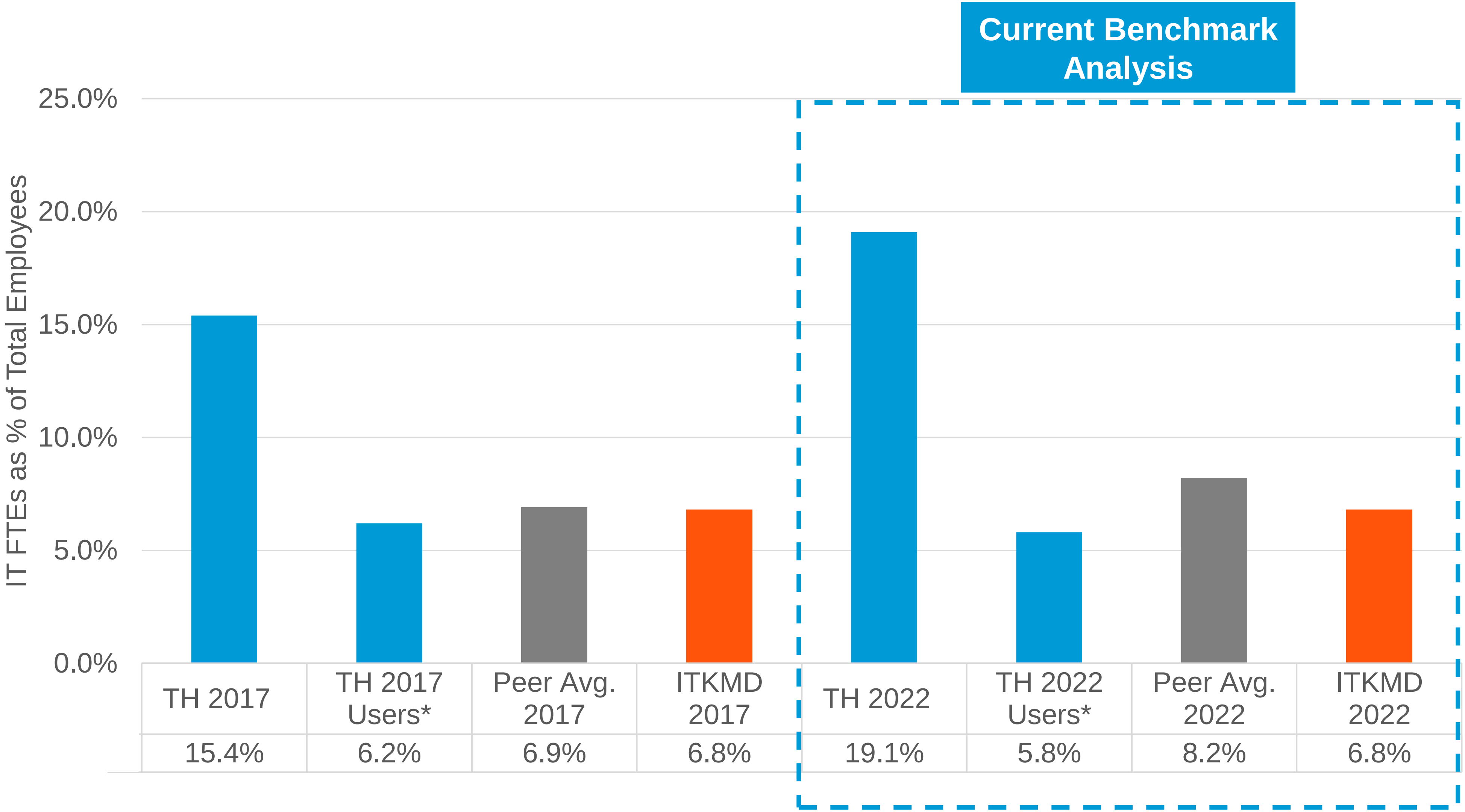
Observations

- IT FTEs as a % of Total Users is 29% below the peer group average and 15% below the ITKMD average for the utilities industry
- Given TH's usage of contract employees, Gartner has used the IT FTEs as a % of Users metric rather than IT FTEs as a % of Employees*

Description	• The percentage of IT FTEs in the organization compared to the total number of employees is a key measure of how critical IT support is to the business. This measure can be heavily influenced, however, by the level of outsourcing an organization may have. • Organizations with high levels of manageability and automation should require fewer operations staff. Manual processes and lack of standards will increase the number of IT FTEs needed.	
Definition	IT FTEs includes in-house and contractor FTEs, does not include managed services adjusted FTEs. Organization Employees includes employees, exclusive on Contractors.	
Calculation	IT FTEs / Organization Employees	**Toronto Hydro: 238 / 1,245**

* Gartner's benchmarking definition for "employees" does not include contractors. This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors.

IT FTEs as Percentage of Total Employees – Multi Year View

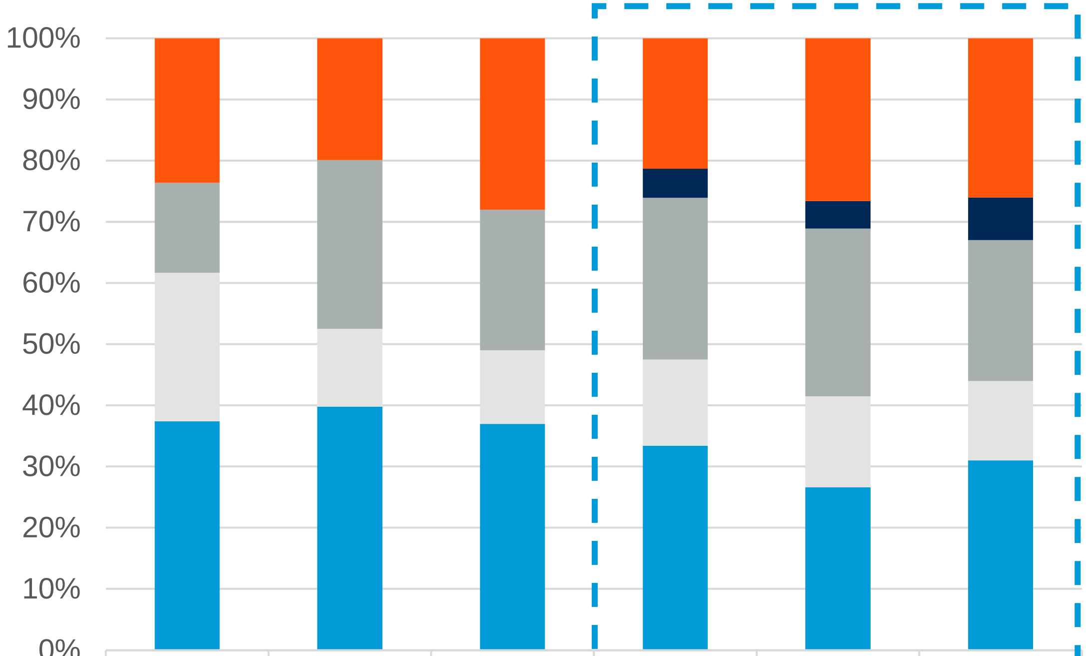


TH 2017	TH 2017 Users*	Peer Avg. 2017	ITKMD 2017	TH 2022	TH 2022 Users*	Peer Avg. 2022	ITKMD 2022
15.4%	6.2%	6.9%	6.8%	19.1%	5.8%	8.2%	6.8%

* Gartner's benchmarking definition for "employees" does not include contractors. This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors.

IT Spend Distribution by Cost Category

Current Benchmark Analysis



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
External Services	23.6%	19.9%	28.0%	21.3%	26.6%	26.0%
Software (SaaS)				4.8%	4.5%	7.0%
Software (On-Prem)*	14.7%	27.6%	23.0%	26.4%	27.4%	23.0%
Hardware	24.3%	12.7%	12.0%	14.1%	14.9%	13.0%
Personnel	37.4%	39.8%	37.0%	33.4%	26.6%	31.0%

Observations

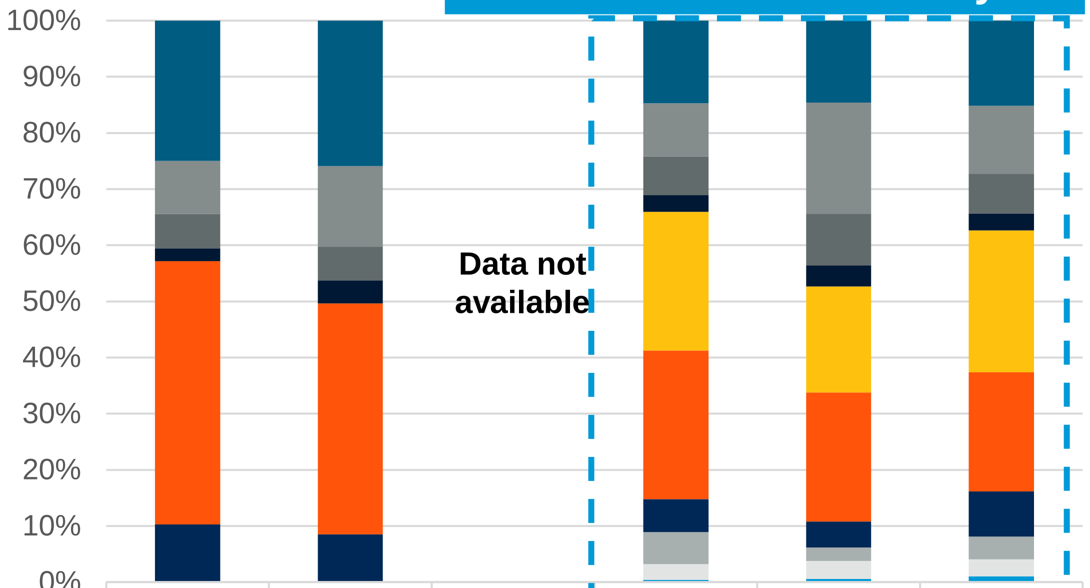
- Toronto Hydro relies less on Outsourcing (21.3% of IT spend in 2022) than the peer group (26.6%). This is balanced by a higher allocation to Personnel (33.4% of IT spend in 2022) as compared with the peer group (26.6%).
- Allocation to both hardware (14.1% of IT spending in 2022) and software (31.2% of IT spending in 2022) is virtually the same as the peer group.

Description	• This measure can be helpful in adding context to the IT investment strategy from a sourcing perspective, in terms of accounting-based resources that may be insourced versus services delivered by a third party. • As an organization increases or decreases the level of outsourced services, it may find an inverse effect in its associated personnel, hardware and/or software expenditures, depending on the scope of services retained and on requirements.
Definition	Allocated IT Spending among the different cost categories

* In 2017 Gartner benchmarking did not separate Software as a Service (SaaS) from On-Premises Software. 2017 “Software (On-Prem)” includes all software spending.

IT Spend Distribution by IT Functional Area

Current Benchmark Analysis



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
Enterprise Computing	25.0%	25.9%		14.7%	14.6%	15%
Network	9.5%	14.4%		9.5%	19.8%	12%
Workplace Services	6.1%	6.0%		6.9%	9.2%	7%
IT Service Desk	2.3%	4.1%		3.0%	3.8%	3%
Application Development				24.7%	18.9%	25%
Application Support*	46.9%	41.2%		26.5%	23.0%	21%
Governance & Service Management**	10.3%	8.5%		5.9%	4.6%	8%
IT Security				5.7%	2.4%	4%
IT Ops. Mgmt				2.8%	3.2%	3%
Ser. Con't / DR				0.4%	0.6%	1%

Observations

- Overall allocation to Applications spending is more than the peer group (51.2% of IT spend versus 41.9%). This is normal during a period of transformation. Applications spending is the largest contributor to the overall increase in IT spending when compared with 2017, up $18 million.
- The allocation to IT Management & Administration (which includes Governance & Service Management, IT Security, IT Operations Management and Service Continuity / Disaster Recovery) was 14.8%, as compared to 10.8% for the peer group. Increased investment in Cyber Security services and capabilities is the main reasons for this variance.

Description	• This information is often leveraged in tandem with IT resource planning exercises, wherein resource allocations can be viewed in terms of IT infrastructure versus applications versus IT overhead. • While this measure is helpful in identifying relative volumes of IT resource consumption by IT functional area, as compared to Peers, it does not aid in identifying whether resources are being leveraged in a cost-effective or productive manner.
Definition	Allocated IT Spending among the different functional areas

* In 2017 application development and application support were not separated
** In 2017 Governance & Service Management included IT Security, IT Operations Management and Service Continuity / Disaster Recovery

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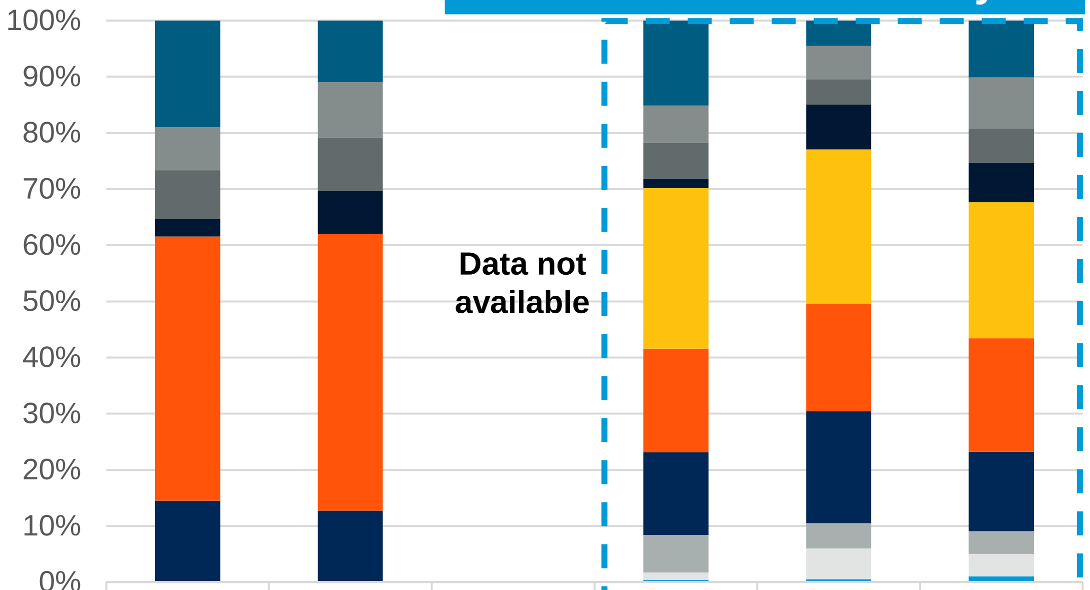
IT FTEs Distribution by IT Functional Area

Current Benchmark Analysis



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
Enterprise Computing	19.0%	10.9%		15.1%	4.5%	10%
Network	7.7%	9.9%		6.7%	6.0%	9%
Workplace Services	8.7%	9.5%		6.3%	4.4%	6%
IT Service Desk	3.1%	7.6%		1.7%	8.0%	7%
Application Development				28.6%	27.5%	24%
Application Support*	47.2%	49.2%		18.5%	19.1%	20%
Governance & Service Management**	14.5%	12.7%		14.7%	19.9%	14%
IT Security				6.7%	4.5%	4%
IT Ops. Mgmt				1.3%	5.5%	4%
Ser. Con't / DR				0.4%	0.5%	1%

Observations

- IT FTE distribution for TH is similar to the peer group with the exception of Enterprise Computing (235% more), ITSD (78% less) and IT Operations Management (76% less)
- TH leverages on-site data centers supported by IT FTEs, no cloud infrastructure is used

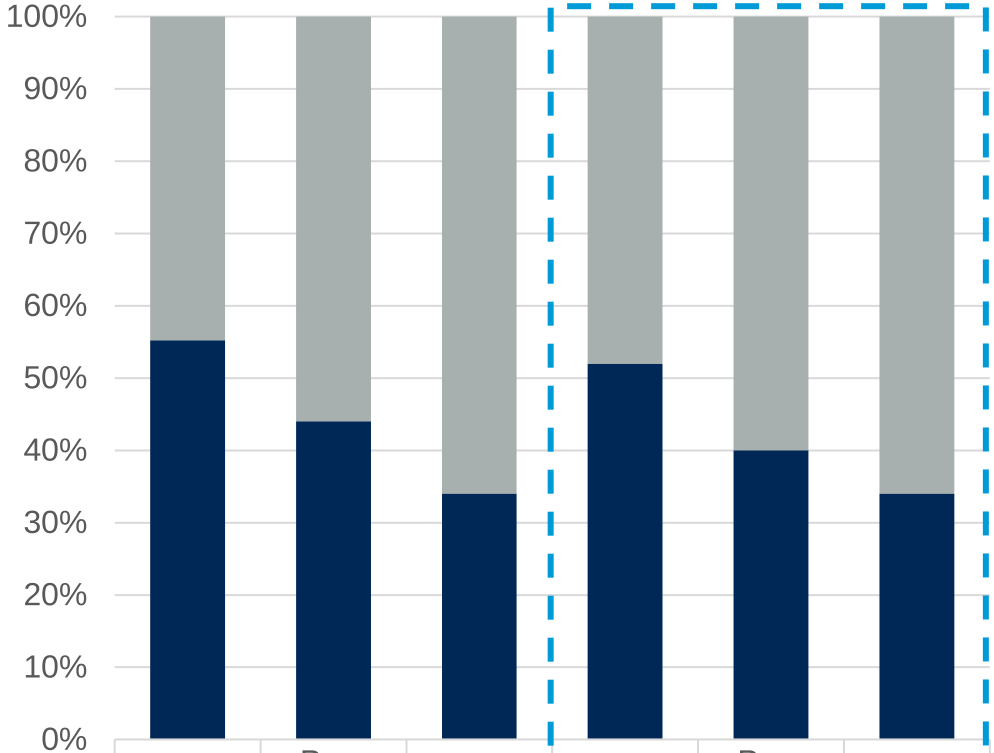
Description	• By viewing human resources (IT FTEs) within the context of the total portfolio, organizations are able to identify which environment is the most labour- intensive as a % of the IT labour pool. Typically, application activities (development and support) demand the most resources from both cost and staffing perspectives. The degree to which an organization outsources should be considered alongside such staffing metrics.
Definition	Distributes In House and Contractor IT FTEs among the different functional areas

* In 2017 application development and application support were not separated

** In 2017 Governance & Service Management included IT Security, IT Operations Management and Service Continuity / Disaster Recovery

IT Spend Distribution – Operations vs. Capital

Current Benchmark Analysis



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
Operational	45%	56%	66%	48%	60%	66%
Capital	55%	44%	34%	52%	40%	34%

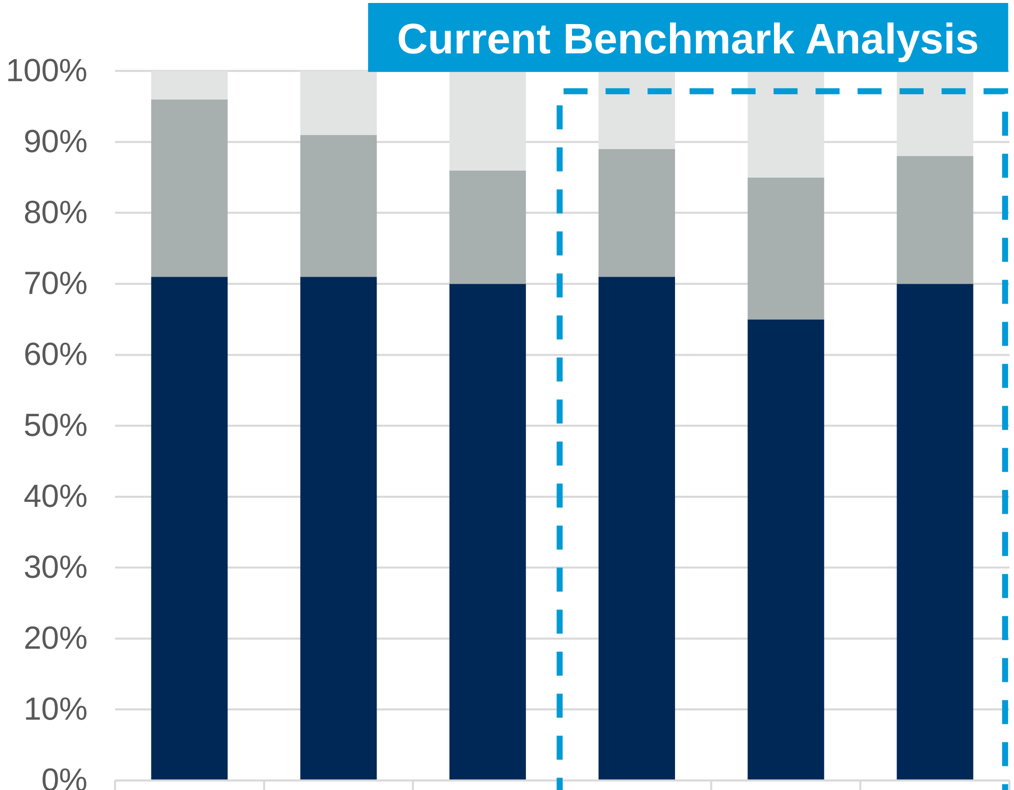
Observations

- TH allocated more of its IT spending to capital (52%) than the peer group average of 40%
- Applications and Infrastructure are increasingly cloud-based, creating an escalating shift away from more traditional capital-based models to operational funding.
- There can be unanticipated or overlooked operating budget increases as a result of Software as a Service (SaaS) and Infrastructure as a Service (IaaS) contracts. The resultant shift from capital expenditure (CapEx) to operating expenditure (OpEx) can cause budgetary and cost management pressures.

Description	• IT capital expenses vs. operational expenses helps to portray the investment profile for an organization in a given year.
	• Organizations with a higher capital spending may…
	  ○ Be investing heavily in strategic IT infrastructure
	  ○ Have reached a planned point of investment in their infrastructure lifecycle
	  ○ Not have been managing asset investments well (i.e., “catching up”)
	  ○ Simply have a more aggressive capitalization policy
	• The break out of Run, Grow, Transform spending that follows may provide more insight

Definition	Distribution of IT Operational spending versus Capital spending

IT Spend Distribution by Run, Grow and Transform



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
Transform	4%	9%	14%	11%	15%	12%
Grow	25%	20%	16%	18%	20%	18%
Run	71%	71%	70%	71%	65%	70%

Observations

- In 2022, Toronto Hydro allocated 29% of IT Spending to "change the business" activities (18% Grow and 11% Transform), similar to the peer group average of 35% and the 2017 level of 29%
- However, TH allocated more to the "Transform" category in 2022 (11%) compared with 2017 (4%). This is the result of digital transformation investments.

Description	• The distribution of IT spending provides a view of the investment profile in business terms (how IT will enable the business to grow or transform revenue, operating income and/or profit margins)
Definition	Allocation of IT Spending by Run, Grow and Transform, where: • 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

04
IT Maturity Assessment Analysis

Toronto Hydro’s IT Assessment is focused on process maturity and spending & staffing as compared to peer organizations

Section 4.0 Focus

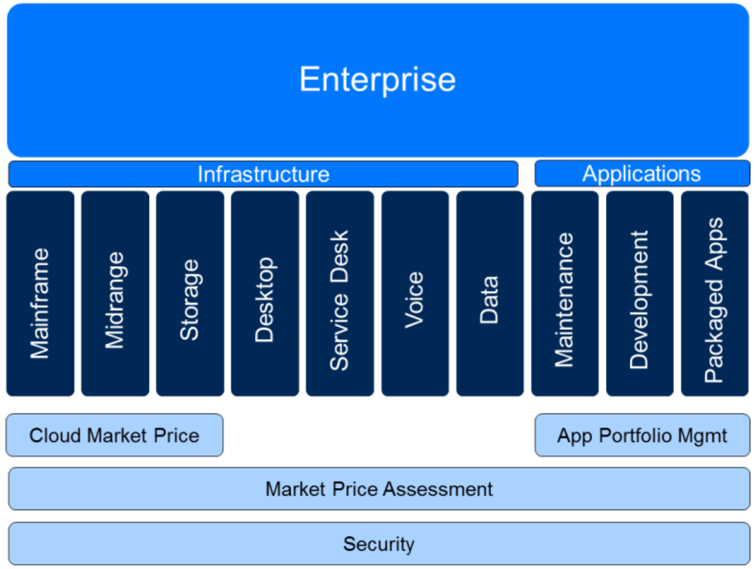
PROCESS MATURITY

Current State Assessment of IT Functional Areas:

- CIOs (IT Governance, IT Finance, Performance Mgmt.)
- Applications
- Data & Analytics
- Enterprise Architecture & Technology Innovation
- Infrastructure & Operations
- Program & Portfolio Management
- Security & Risk Management

+

SPENDING AND STAFFING



- IT$ / Rev
- IT$ / Opex
- IT FTEs / FTE
- Run/Grow / Transform

Gartner

IT Maturity Assessment Methodology Overview

Gartner used its industry-leading IT maturity models (IT Score) to evaluate Toronto Hydro's IT capabilities across the in-scope domains relative to peers. IT Score provides insights on maturity and importance to gain perspective on the highest priority activities to improve.

Maturity

- Measured on a scale ranging from 1 (low) to 5 (high), maturity measures how advanced an activity is relative to Gartner's best-practice research.

Importance

- Measured on a scale ranging from 1 (unimportant) to 5 (critical) based on participants' inputs, importance measures how important each activity is to the overall effectiveness in meeting objectives.

Prioritization

- Activity priority index (API) identifies the activities that should be prioritized for improving maturity. It is defined as the average gap between importance and maturity and is computed for each activity and weighted by its average importance.

Gartner

Analysis Notes

- Toronto Hydro completed Gartner’s IT Score surveys to baseline current maturity and importance levels
- Results were reviewed and calibrated across IT domains in working sessions with Gartner and the Toronto Hydro project team

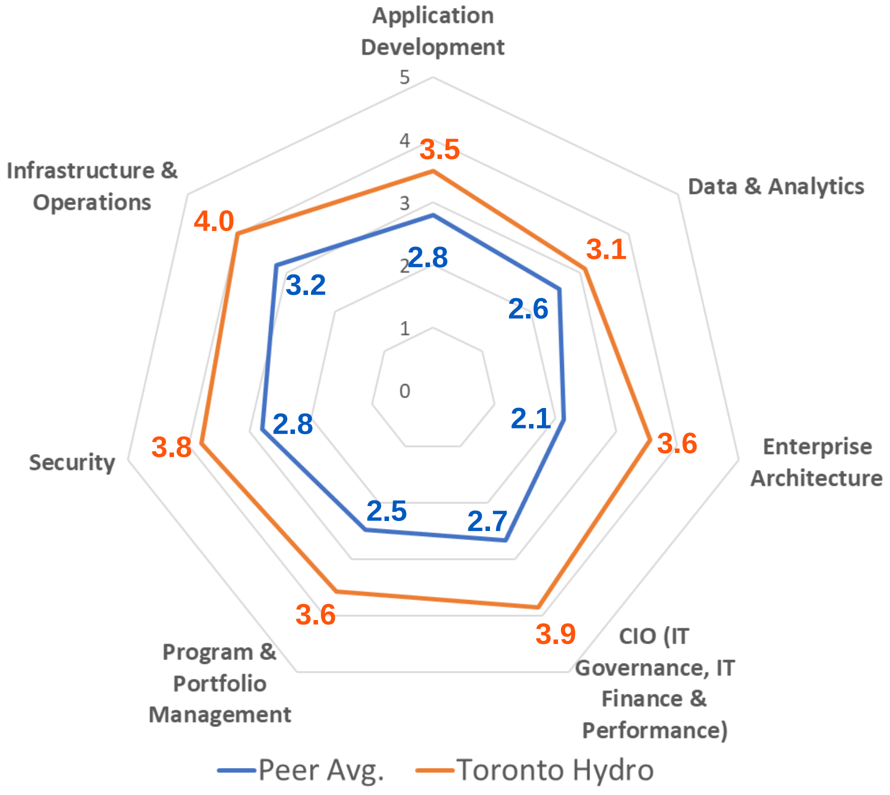
The IT capability assessment showed that Toronto Hydro's maturity across all domains is slightly higher than peers

- Toronto Hydro was compared to a peer group of 9 to 14 organizations (depending on data available for each IT domain) from the energy and utility industry with revenues between $1 billion and $3 billion USD
- 64 functional activities across 7 IT domains were assessed by comparing Toronto Hydro's current state (as defined by IT domain leadership) to Gartner's best practices.
- Toronto Hydro's overall IT maturity was 3.6 compared to 2.7 for the peer group. Higher levels of maturity were seen across all domains included in the scope of the assessment. This reflects Toronto Hydro's focus and investment in maturing IT capabilities.
- Within Toronto Hydro, Infrastructure & Operations (I&O) was the most mature domain at 4.0 and Data & Analytics (D&A) was the least mature at 3.1. I&O is a well-established domain whereas D&A is relatively new, hence these results are not surprising.
- Steady efforts have been made to improve capabilities within the Program & Portfolio Management, Enterprise Architecture and IT Security domains.
- Assessing maturity results relative to peers is interesting, however, comparing current maturity levels with how important the capability is for the organization to achieve its overall objectives is more important (see next page).

IT Domain Maturity Levels

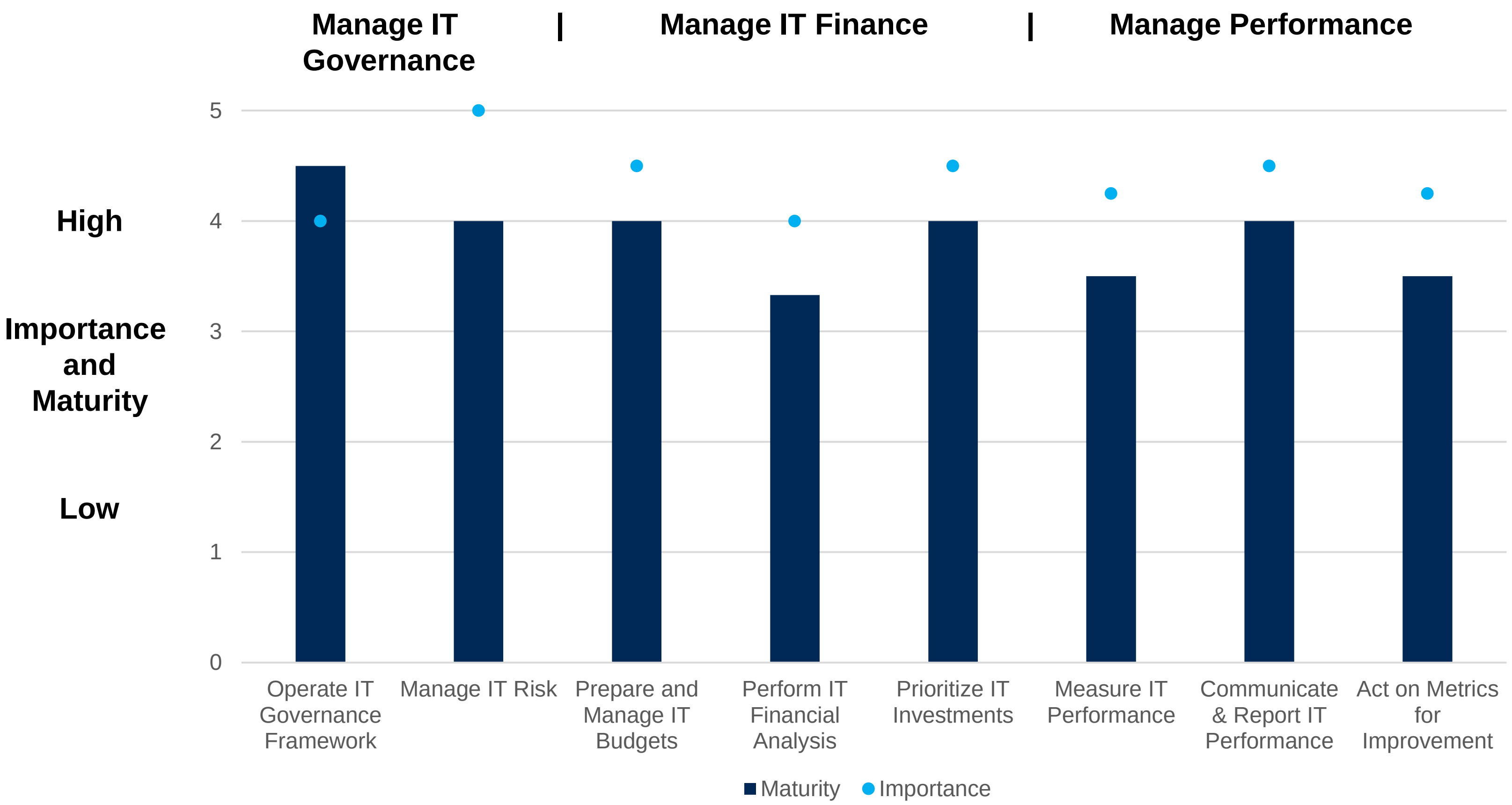
Toronto Hydro's Overall IT Maturity Level: 3.6

Peer Maturity Level: 2.7



Maturity scores are assessed on a scale from 1-5, with the score of 5 representing Gartner's best practices for the IT domain

Chief Information Officer (CIO)
How Do Maturity and Importance Compare?



Lowest Maturity
- Perform IT Financial Analysis
- Measure IT Performance
- Act on Metrics for Improvement

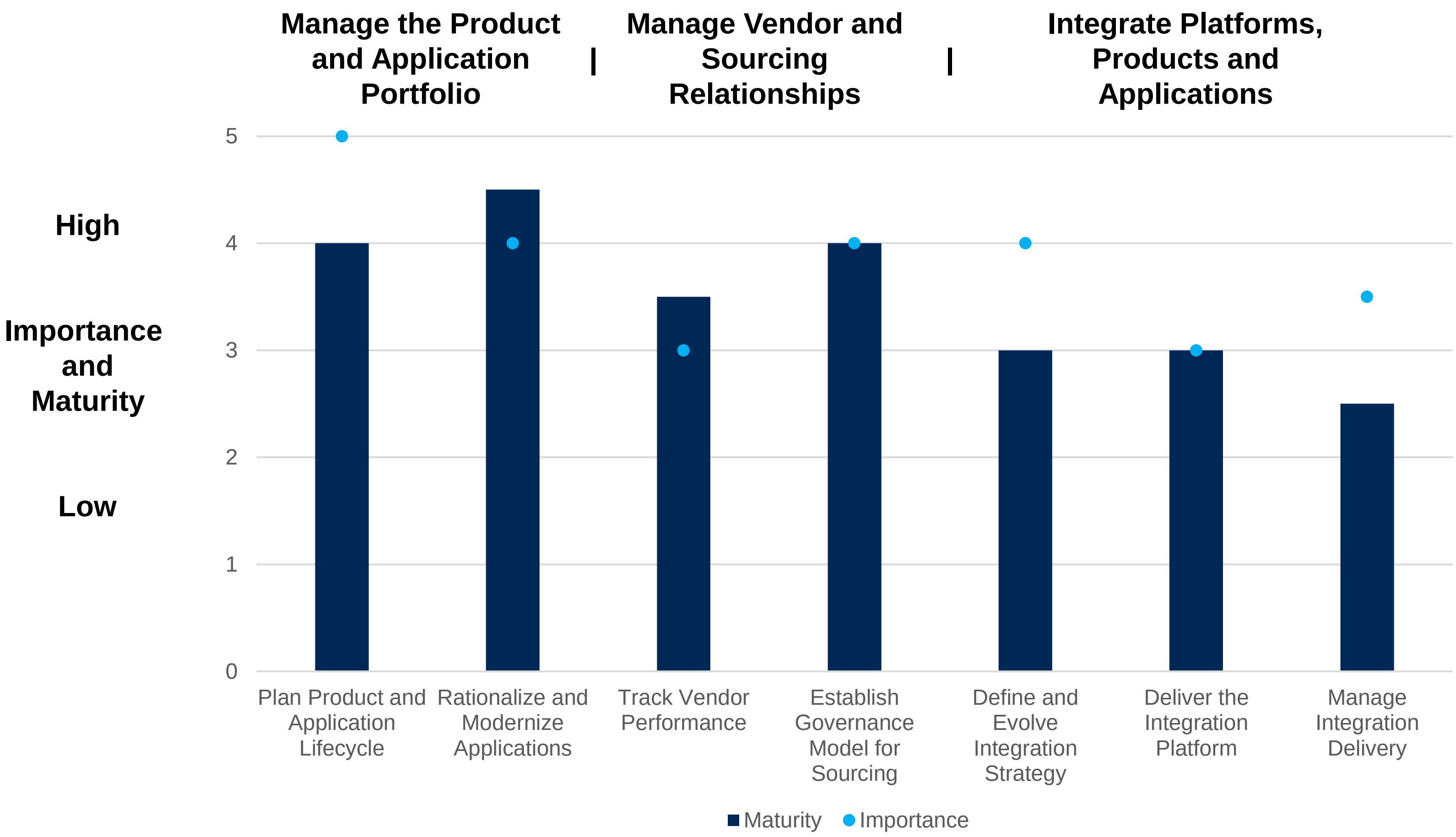
Highest Importance
- Manage IT Risk
- Prepare and Manage IT Budgets
- Prioritize IT Investments

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Chief Information Officer (CIO) Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Manage IT Governance	Operate IT Governance Framework	4.5	4: the IT governance framework is adaptive and enables the agility of I&T decision making across the enterprise 5: the IT governance framework enabled autonomous I&T decision making across the ecosystem, digital platform and enterprise
	Manage IT Risk	4.0	4: an IT risk discipline considers both risk and reward on I&T decision making from a business and perspective. The business carried formal accountability for IT risk as part of its enterprise risk management.
Manage IT Finance	Prepare & Manage IT Budgets	4.0	4: I&T budgets are aggregated across the enterprise and support products. Budgets are compared with actual performance and revised at least quarterly to accommodate changing business priorities
	Perform IT Financial Analysis	3.3	3: IT performs cost analysis on all I&T across the enterprise as part of the formal monthly or quarterly IT management process. I&T spending by service is well understood by business unit and includes measurement and reporting against business-based SLAs. Spending optimization initiatives include joint business and IT savings 4: IT streamlines and automates financial analysis, which emphasizes growth and competitive differentiation. IT performs financial analysis at the I&T product level in terms that the business understands. IT and business leaders follow an adaptive, iterative, organization-wide value-optimization process
	Prioritize IT Investments	4.0	4: the CIO and senior enterprise executives prioritize all investments at the enterprise level at least quarterly to achieve innovation and differentiation. Business cases for I&T requests contain business outcomes and use specific value and risk methods.
Manage Performance	Measure IT Performance	3.5	3: IT performance is measured through business-value-based SLAs that correlate to business outcomes and employee experience. 4: IT and business performance is fused and jointly measured through strategic business benefits realization and external customer / citizen satisfaction.
	Communicate & Report IT Performance	4.0	4: IT proactively communicates to senior business executives how I&T across the enterprise is leveraged for business capabilities and competitive differentiation, which influences strategy and innovation investments
	Act on Metrics for Improvement	3.5	3: The IT organization has defined a process-to-service map that identified IT processes' relationship to IT service outcomes, and remediation efforts result in improvements in end-to-end service quality. 4: Empowered, multidisciplinary business/IT product teams prioritize their own continuous improvement objectives for products, business processes, business outcome and external customer / citizen experience

Applications
How Do Maturity and Importance Compare?



Lowest Maturity
- Manage Integration Delivery
- Deliver the Integration Platform
- Define and Evolve Integration Strategy

Highest Importance
- Plan Product and Application Lifecycle
- Rationalize and Modernize Applications
- Establish Governance Model for Sourcing
- Define and Evolve Integration Strategy

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Applications
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Manage the Product & Application Portfolio	Plan Product & Application Lifecycle	4.0	4: the product and application roadmaps include opportunities of emerging technology for the next 2-5 years
	Rationalize & Modernize Applications	4.5	4: rationalization and modernization initiatives are integral part of business transformations 5: rationalization and modernization of products and applications is continuous and a separate discipline with dedicated resourced and ongoing funding
Manage Vendor & Sourcing Relationships	Track Vendor Performance	3.5	3: a role of vendor manager is established to track groups of vendors and associated records. Formal spreadsheets (scorecards) are put in place to ensure consistency of tracking across vendors 4: performance of all vendors is institutionalized, and organization uses it to derive insight to assist with vendor selection. Internal customers are polled to obtain full measure of overall customer satisfaction for each vendor
	Establish Governance Model for Sourcing	4.0	4: vendor relationships are managed by a team that has representation from all business sectors to ensure cross-organization representation
Integrate Platforms, Products & Applications	Define and Evolve Integration Strategy	3.0	3: an integration strategy team is established to provide integration delivery services to the applications teams. A formal centrally managed sourcing strategy is available
	Deliver the Integration Platform	3.0	3: one or more strategic integration tool has been selected, recommended and centrally supported. Integration solutions are implemented on the strategic tools by consistently adopting centrally defined common patterns and guidelines
	Manage Integration Delivery	2.5	2: application delivery teams autonomously address integration issues, optionally using a set of approved products that are supported by an integration platform team 3: an integration strategy team is in charge of delivering, on demand, integration solutions and/or strategic tools to support the applications delivery teams

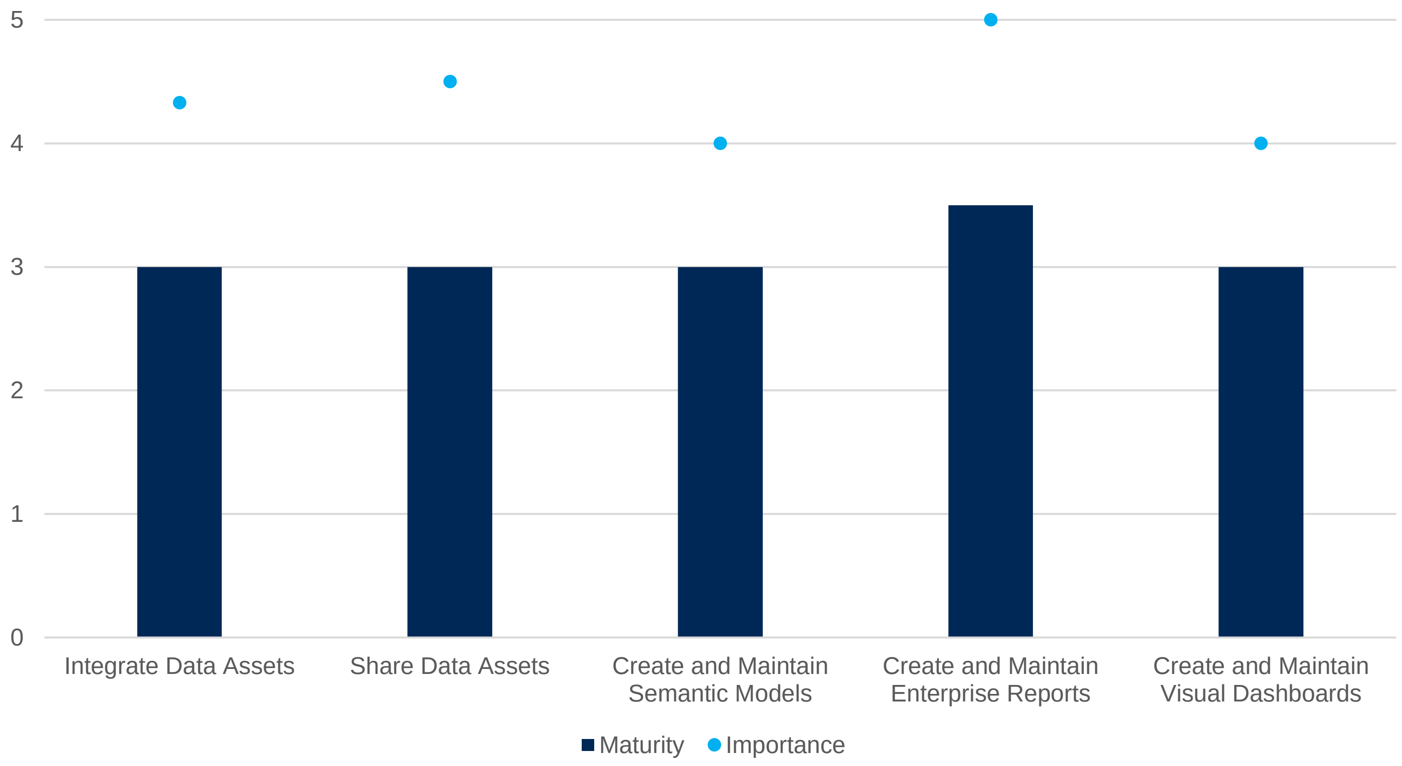
Data & Analytics
How Do Maturity and Importance Compare?

Integrate and Manage Data | **Create and Maintain Analytics Content**

High

Importance and Maturity

Low



Lowest Maturity

- Integrate Data Assets
- Share Data Assets
- Create and Maintain Enterprise Reports
- Create and Maintain Visual Dashoards

Highest Importance

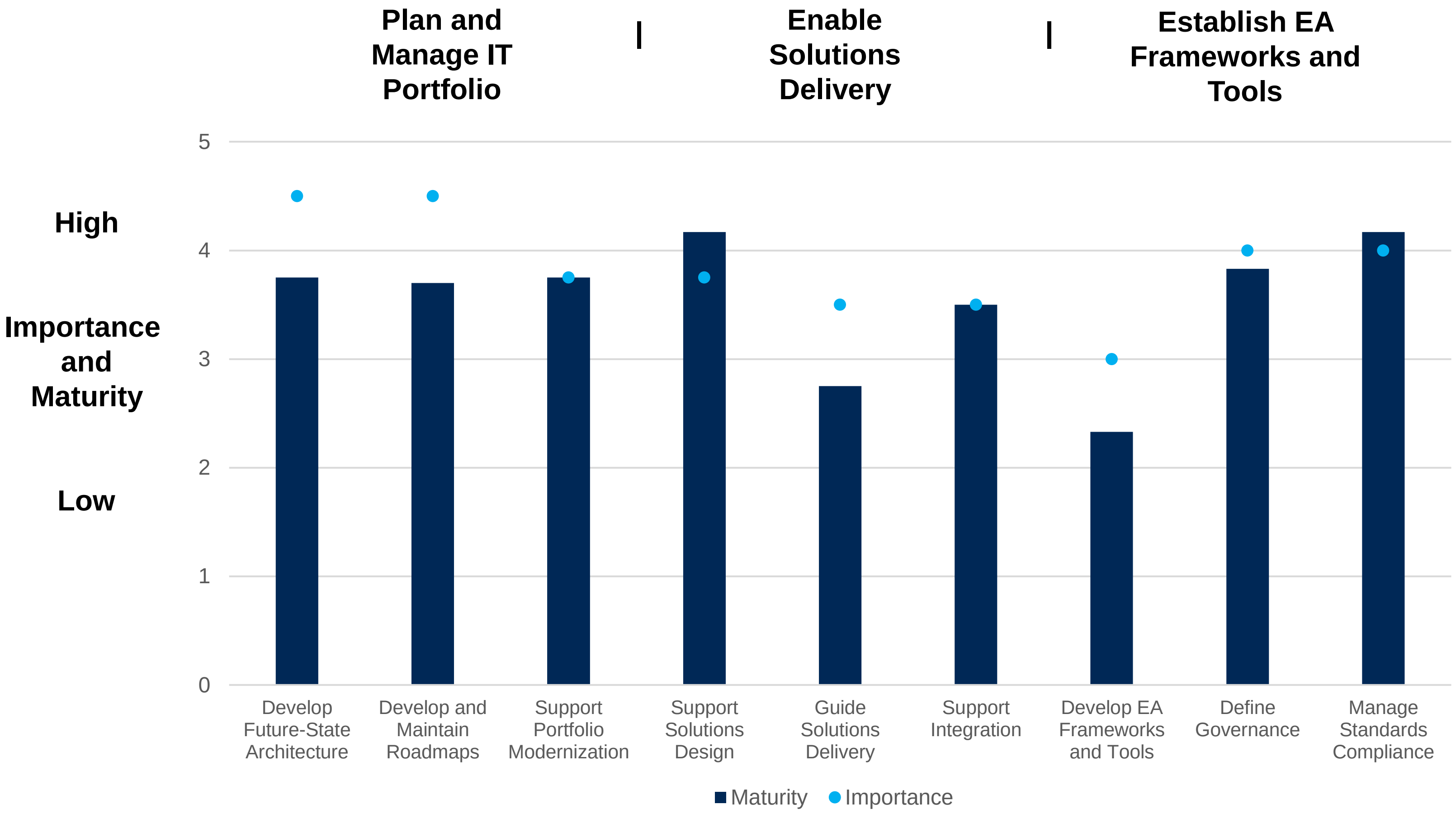
- Create & Maintain Enterprise Reports
- Share Data Assets
- Integrate Data Assets

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Data & Analytics Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Integrate & Manage Data	Integrate Data Assets	3.0	3: data integration practices combine multiple styles of integration to adapt to changing demands within a single use case
	Share Data Assets	3.0	3: data semantics can be shared regionally and mapped over various sources and applications
Create & Maintain Analytics Content	Create & Maintain Semantic Models	3.0	3: semantic models are created by IT and business to facilitate reporting and analysis by clearly defining dimensional attributes and measures
	Create & Maintain Enterprise Reports	3.5	3: there is a consistent process to develop interactive reports. Reports can also be distributed via e-mail 4: consumers of reports access reports using search as opposed to more complicated hierarchical folders. Moreover, reports can be delivered to mobile devices.
	Create & Maintain Visual Dashboards	3.0	3: departments and business units are enables to build their own dashboards. Also, dashboards include geospatial and location intelligence capabilities

Enterprise Architecture & Technology Assessment
How Do Maturity and Importance Compare?



Lowest Maturity
- Develop EA Frameworks and Tools
- Guide Solutions Delivery

Highest Importance
- Develop Future State Architecture
- Develop and Maintain Roadmaps

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Enterprise Architecture & Technology Assessment (1 of 2)
Current Maturity Levels

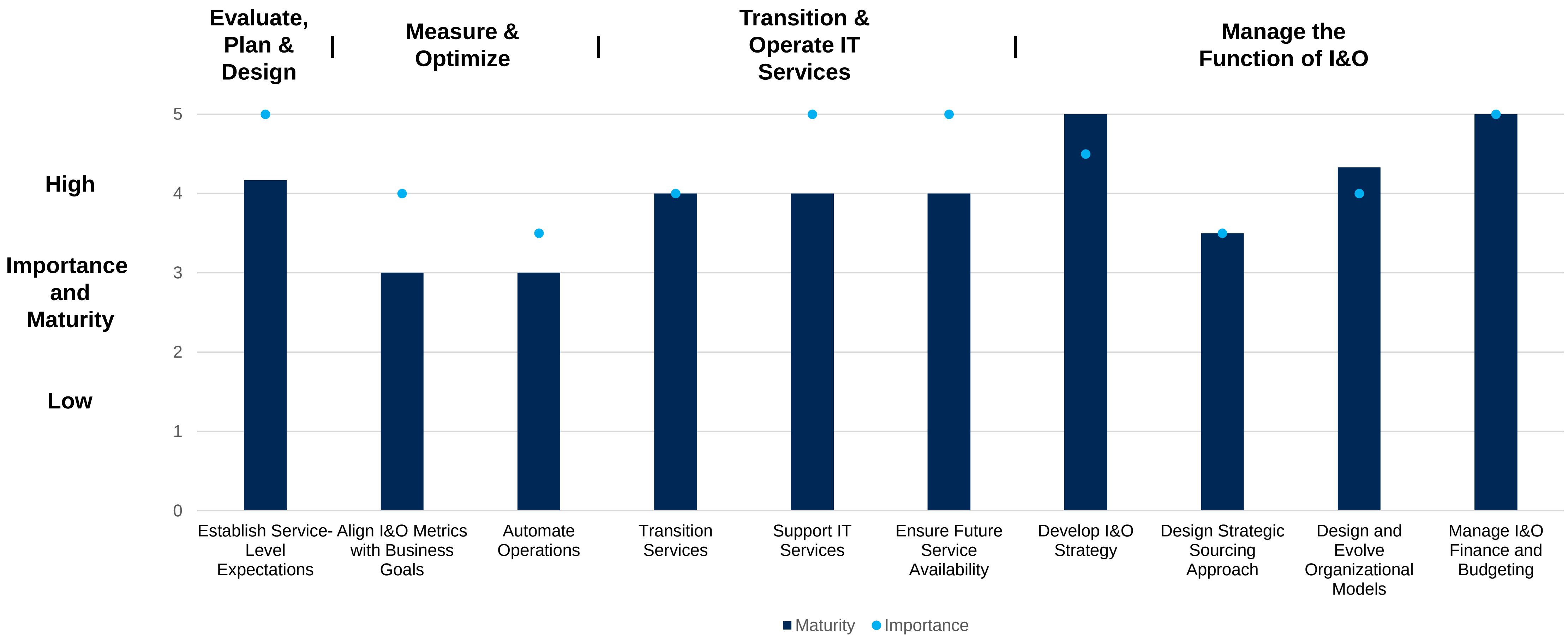
Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Plan & Manage IT Portfolio	Develop Future-State Architecture	3.8	3: EA coordinates with stakeholders to create an enterprise future-state plan across technology domains and/or business areas 4: EA regularly recalibrates the future-state plan based on criticality of business capabilities and technical debt
	Develop & Maintain Roadmaps	3.8	3: EA applies a formal process to roadmap how IT initiatives support business capabilities, while tracking project ro product costs, benefits, risks and interdependencies 4: EA continuously reviews and refreshes roadmaps that reflect multiple time horizons and business scenarios designed to improve or maintain capability health
	Support Portfolio Modernization	3.8	3: EA has a comprehensive view across the technology stack and advises IT delivery teams on sunset or update decisions based on an analysis of costs and benefits and business needs 4: EA tracks how existing technologies support business capabilities and targeted outcomes and makes recommendations based on opportunity cost and impact on speed to value
Enable Solutions Delivery	Support Solutions Design	4.2	4: EA helps development teams apply a customer-centric lens to solutions design and supporting architectural decisions for improved usability
	Guide Solutions Delivery	2.8	2: EA engages with development teams across the delivery life cycle through a stage-gated process to review compliance with internal standards 3: EA provides packaged guidance to keep solutions development on track with targeted business outcomes and manage risk to business processes and operations
	Support Integration	3.5	3: EA manages reusable services (APIs) and defines standards to support ease of integration 4: EA regularly assesses integration standards for relevance and defines and curates reusable services that accelerate integration

Enterprise Architecture & Technology Assessment (2 of 2) Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Establish EA Frameworks & Tools	Develop EA Frameworks & Tools	2.3	2: EA develops use cases to demonstrate the value of tools and frameworks and to justify investment. Usage is prescriptive and in support of projects or products, focusing on gathering artifacts, documentation and modeling 3: ES assess tool and framework utility holistically to best support future and current-state architecture
	Define Governance	3.8	3: EA aligns the governance framework with IT strategy and includes business context and cross-functional perspectives in strategic review of technology standards 4: EA connects governance with enterprise digital strategy by means of a forum like a strategy review board and analyyzes exceptions to review and update standards
	Manage Standards Compliance	4.2	4: EA promotes guardrails by offering self-service tools, highlighting business benefits such as speed and innovation and accelerating remediation for granted exceptions

Gartner

Infrastructure & Operations
How Do Maturity and Importance Compare?



Lowest Maturity
- Align I&O metrics with Business Goals
- Automate Operations
- Design Strategic Sourcing Approach

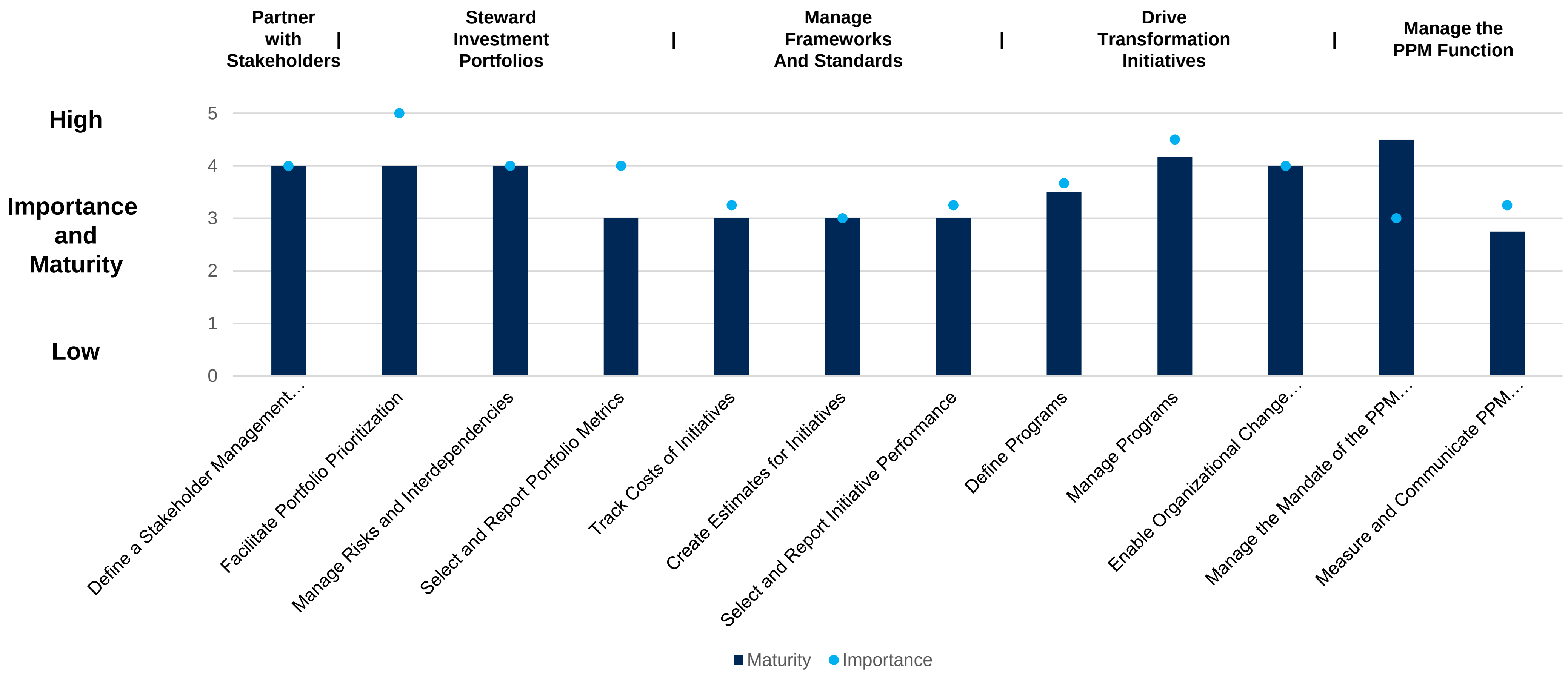
Highest Importance
- Establish Service-Level Expectations
- Support IT Services
- Ensure Future Service Availability
- Manage I&O Finance and Budgeting

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Infrastructure & Operations Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Evaluate, Plan & Design	Establish Service-Level Expectations	4.2	4: service levels that support critical business processes are defined and monitored in terms of their impact on user experience and critical workflows
Measure & Optimize	Align I&O Metrics with Business Goals	3.0	3: I&O is informed of business goals associated with applications and projects and generates periodic status and performance reports to the business in standard formats
	Automate Operations	3.0	3: automation is used to perform frequently repeated tasks, and staff has access to training on automation tools
Transition & Operate IT Services	Transition Services	4.0	4: a clear and robust service design process is in place, incorporating complete requirements. DevOps automation delivers business value quickly and effectively
	Support IT Services	4.0	4: I&O uses a service-based approach, with integrated ITSM and operational management tools. Key process owner, service owner and product owner roles are in place
	Ensure Future Service Availability	4.0	4: asset relationships are developed and stored in a CMDB; the estate is monitored at the service level; and measures are in place to manage the estate and deliver higher availability and stability
Manage the Function of I&O	Develop I&O Strategy	5.0	5: build strategies in collaboration with business partners, and follow agile methodology to respond quickly and adapt iteratively to enable changes in business priorities and strategies
	Design Strategic Sourcing Approach	3.5	3: base sourcing decisions on enterprise needs, cost optimization and categorized vendors. Determine solutions in collaboration with other IT teams 4: base sourcing decisions on fit-for-purpose analysis and identify solutions in collaboration with IT partners and input from business
	Design & Evolve Organizational Models	4.3	4: map out critical handoffs between teams and organize team members around service delivery 5: support cross-functional teams)such as DevOps teams or automation centers of excellence) and organize around IT products and/or business goals
	Manage I&O Finance & Budgeting	5.0	5: explain to business leaders how financial decisions positively affect business objectives and ensure transparency by engaging stakeholders to drive informed IT consumption behaviour

Program & Portfolio Management
How Do Maturity and Importance Compare?



Lowest Maturity
- Measure and Communicate PPM Performance

Highest Importance
- Facilitate Portfolio Prioritization
- Manage Programs

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Program & Portfolio Management (1 of 2)
Current Maturity Levels

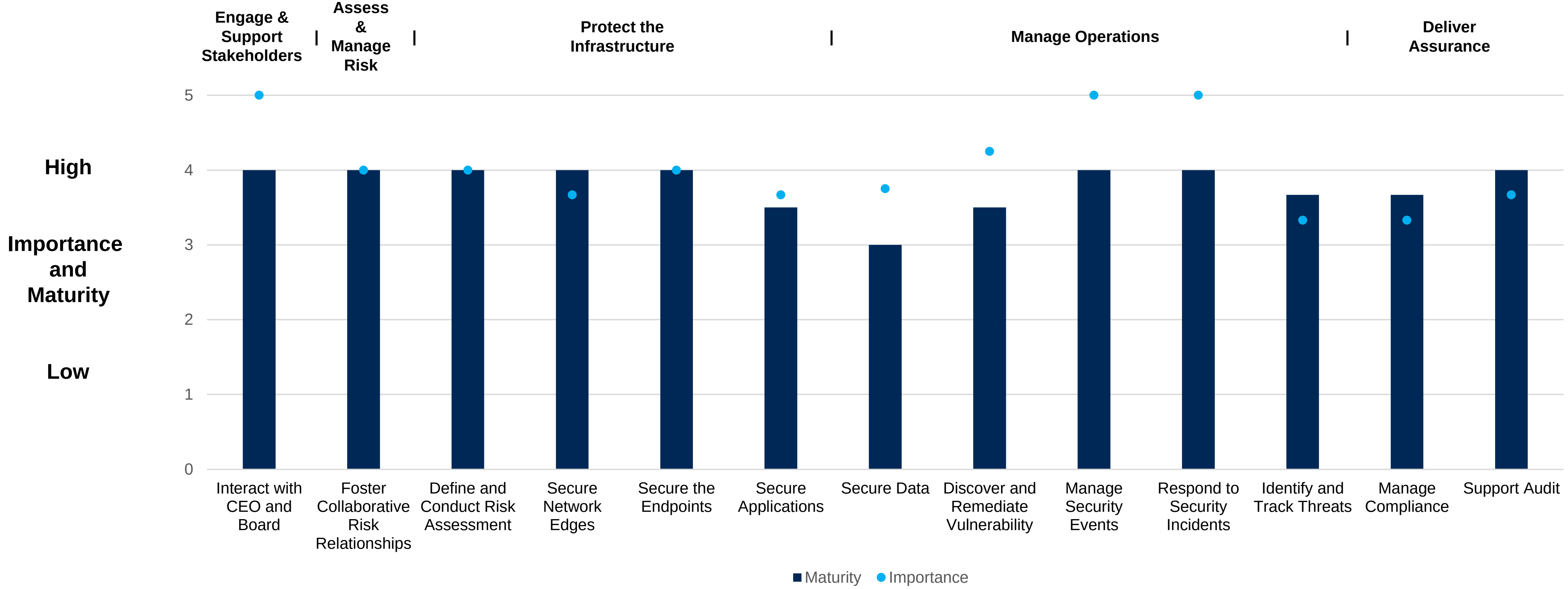
Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Partner With Stakeholders	Define a Stakeholder Management Approach	4.0	4: the PPM function helps product, project or program managers classify their stakeholders based on their communication styles and challenge stakeholder assumptions when necessary
Steward Investment Portfolios	Facilitate Portfolio Prioritization	4.0	4: the PPM function’s support enables portfolio decision makers to align roadmaps with organization objectives, define a target portfolio structure based on the relative importance of business capabilities and reprioritize as the investment roadmap changes
	Manage Risks & Interdependencies	4.0	4: the PPM function frequently seeks input on risk to achieving business outcomes from a diverse det of stakeholders and established risk-escalation rules
	Select & Report Portfolio Metrics	3.0	3: the PPM function aggregates, tracks and reports a mix of standard operational and benefit metrics
Manage Framework & Standards	Track Costs of Initiatives	3.0	3: the PPM function defines standard frameworks to track the overall costs of initiatives
	Create Estimates for Initiatives	3.0	3: the PPM function tailors the approach to estimation and level of support depending on the characteristics of the initiative and uses input from experienced estimators to improve the accuracy of estimates.
	Select & Report Initiative Performance	3.0	3: the PPM function uses standard metrics, tailors its reporting approach to fir context and need, and enables self-service tools for stakeholders

Gartner

Program & Portfolio Management (2 of 2) Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Drive Transformation Initiatives	Define Programs	3.5	3: programs are proactively defined to manage technical, or resource dependencies related to a common business objective 4: programs are defined top-down to support business capabilities and are assessed on measurable business outcomes
	Manage Programs	4.2	4: the PPM function takes a program-centric view of resource allocation, budge reprioritization and design of the program manager role
	Enable Organizational Change Management	4.0	4: the PPM function sequences change initiatives and adjusts change management approached to drive adoption
Manage the PPM Function	Manage the Mandate of the PPM Function	4.5	4: the PPM function defines its activities as a set of services to meet t he varied needs of stakeholders 5: the PPM function reshapes its mandate or temporarily fixes the way it engages with key stakeholder to align with the evolving priorities of the digital business
	Measure & Communicate PPM Performance	2.8	2: the PPM function reports basic initiative-level metrics to stakeholders at regular intervals 3: the PPM function tracks the function’s performance against operational and strategic objectives and provides customized reports to stakeholders

Security & Risk Management
How Do Maturity and Importance Compare?



Lowest Maturity
- Secure Data
- Secure Applications
- Discover and Remediate Vulnerabilities

Highest Importance
- Interact with CEO and Board
- Manage Security Events
- Respond to Security Incidents

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Security & Risk Management (1 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Engage & Support Stakeholders	Interact with CEO & Board	4.0	4: SRM develops and communicates standardized reports in business-friendly language, aligned to business objectives that are made available to the board and CEO on a regular basis
	Foster Collaborative Risk Relationships	4.0	4: SRM works with other stakeholders on future challenges and encourages staff across functions to minimize activity duplications and maximize collaboration
Assess & Manage Risk	Define & Conduct Risk Assessments	4.0	4: SRM has defined a risk assessment process that periodically reassesses risk and aggregates findings against a defined taxonomy
Protect the Infrastructure	Secure Network Edges	4.0	4: SRM ensures network access and network traffic within networks are controlled and monitored
	Secure the Endpoints	4.0	4: endpoint security controls are expanded to include detection and response
	Secure Applications	3.5	3: SRM implements automated discovery and security assessment for applications 4: SRM collaborates with application development to implement application security policies and implements monitoring automation
	Secure Data	3.0	3: SRM identifies threats and compliance issues to implement protection and monitoring controls

Gartner

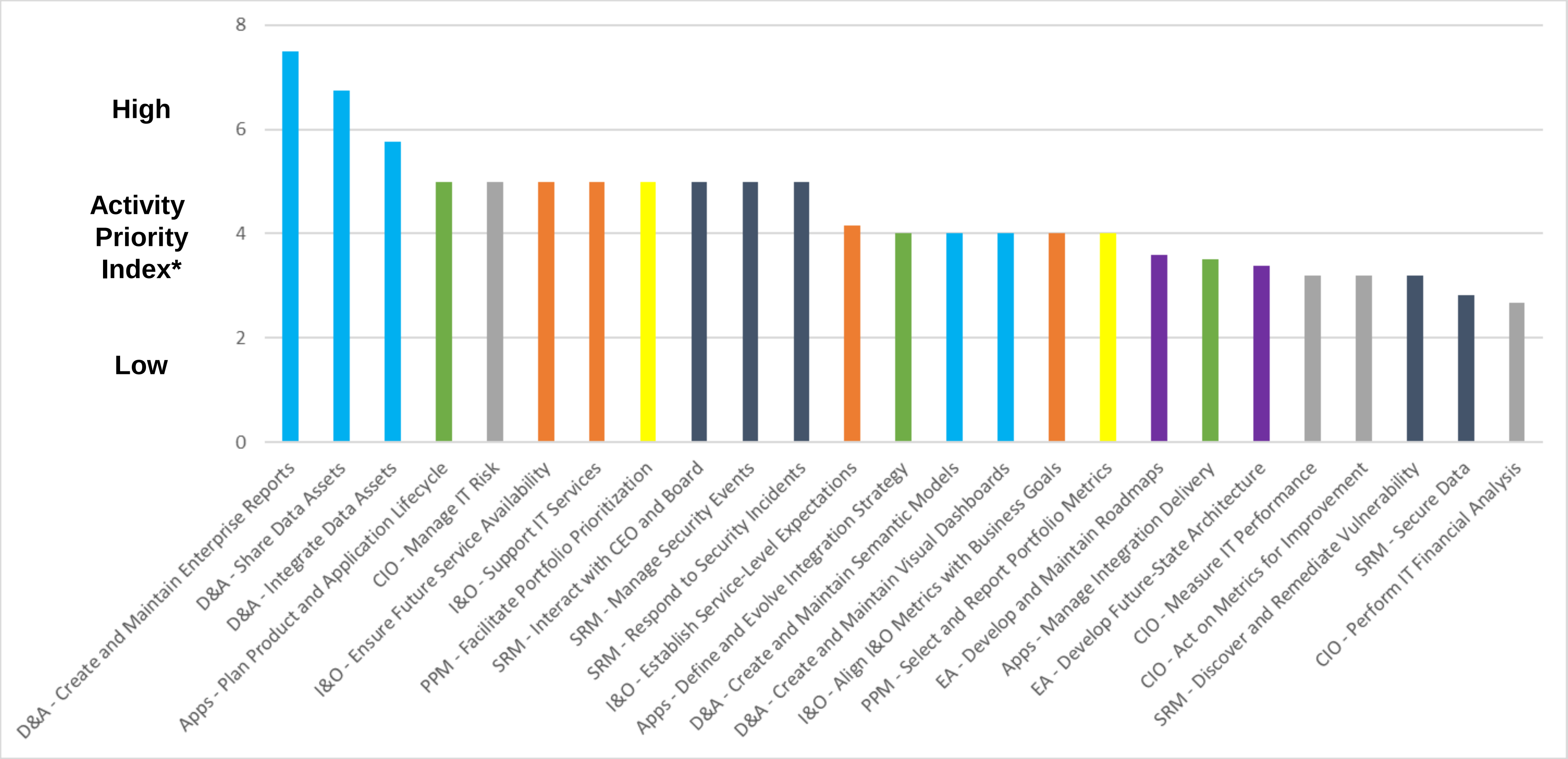
Security & Risk Management (2 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Manage Operations	Discover & Remediate Vulnerabilities	3.5	3: SRM prioritizes vulnerabilities based on business context and monitors patching effectiveness 4: SRM uses threat intelligence to further prioritize vulnerabilities
	Manage Security Events	4.0	4: SRM regularly assesses monitoring effectiveness to increase alert accuracy and uses event and incident data to improve detection accuracy
	Respond to Security Incidents	4.0	4: SRM works with other functions to formalize all aspects of crisis response plans, maintains detailed response playbooks for a variety of incidents and conducts tabletop test on plans
	Identify & Track Threats	3.7	3: SRM uses analytics to identify patterns of threats, reverse-engineers attached to identify indicators of compromises and considers scenarios of future attacks to tailor detection efforts 4: SRM combines internal and external data to develop hypotheses of future attacks, applies attribution techniques across multiple platforms and timelines, and compiles common attacker profiles to tailor monitoring of future attacks
Deliver Assurance	Manage Compliance	3.7	3: SRM typically tracks current regulations and works closely with internal experts to ensure compliance 4: SRM centrally tracks current regulations and works closely with internal and external experts to ensure compliance
	Support Audit	4.0	4: support of audit activities is based on prioritized audit objectives. Partial data collection is based on time and effort analysis to meet audit support requirements

Top 25 Improvement Opportunities: Activity Priority Index (API)

The Activity Priority Index (API) represents an order of priority for the IT functions, based on which below are least mature and of greatest importance for Toronto Hydro

Highest to Lowest Priority Areas for Improvement



*Activity Priority Index: Activity Priority Index (API) for an activity is computed as importance minus maturity multiplied by its importance. A higher API score indicates a greater priority for improvement to the organization.

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